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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON SAFETY, RELIABILITY, AND SERVICE QUALITY FOR 2023; AND PETITION FOR APPROVAL OF ELECTRIC RELIABILITY STANDARDS FOR 2024	DOCKET NO. E002/M-24-27 **ANNUAL REPORT AND PETITION**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the attached Annual Report on our safety, reliability, and service quality performance for 2023. We make this filing pursuant to Minn. R. 7826.0400, 7826.0500, and 7826.1300. This filing also includes our Petition for approval of the Company's proposed reliability standards for the year 2024, as required under Minn. R. 7826.0600. In addition, the Annual Report contains several compliance items from various dockets.

We respectfully request that the Commission accept our annual report for 2023, approve our proposed reliability standards for 2024.

I. DESCRIPTION AND PURPOSE OF FILING

A. Background

Legislation passed in 2001 required that the Commission establish safety, reliability, and service quality standards for electric distribution utilities. After a rulemaking process, the Commission adopted rules that became effective on January 28, 2003. These rules contain both performance standards and reporting requirements. Additionally, the rules require individual utilities to propose electric reliability standards each year for approval by the Commission. Over time, the Commission added additional compliance obligations through various Order Points.

Consistent with last year, we have separated the Annual Report, as laid out in Minnesota Rules, Chapter 7826, Electric Utility Standards, into two parts: Part I contains Service Quality and Reporting standards; Part II contains the Safety and Reliability metrics.

In this Petition, we request the Commission take two actions on the two items listed below:

- Accept the Company's Annual Report for 2023, and
- Approve our proposed reliability standards for 2024.

Each of these are discussed in more detail below.

A. Accept the Company's Annual Report for 2023

Attached to this Petition is the Company's Annual Report, detailing the Company's safety, reliability and service quality performance for 2023. The Company's Annual Report, and its attachments, is consistent with the Minnesota service quality reporting rules found in Minn. R. Ch. 7826, as well as the various Commission Order Points adopted over the years. In addition to responding to the new compliance obligations ordered from the 2017 through 2023 Annual Reports, the Company has included a compliance matrix to assist our stakeholders to find the information they are looking for within the Annual Report. We respectfully request the Commission accept the Company's Annual Report for 2023.

B. Approve Proposed Reliability Standards for 2024

Minn. R. 7826.0600, subp. 1, requires the Company to propose 2024 standards for SAIFI, SAIDI, and CAIDI. The Company proposed setting the 2024 standards based on the 2024 IEEE benchmarking results as follows:

- Statewide reliability: IEEE second quartile for large utilities;
- Metro East and Metro West work centers: IEEE second quartile for large utilities; and
- Southeast and Northwest work centers: IEEE second quartile for medium utilities.

Our proposal is consistent with the 2023 standards established in the Commission's November 9, 2022 Order in Docket No. E002/M-22-162, Order Point 4. Because the IEEE benchmarking data for the previous year is not available until third quarter of the following year, the 2023 benchmarking data will not be available until the summer of 2024. The Company proposes filing to supplement to its 2023 Annual Report providing the 2023 benchmarking information compared to our 2023 results along with an explanation and action plan for any standards not met for 2023.

V. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

Approval of our Annual Report and the reliability performance standards proposed in this Petition will not result in any changes to Xcel Energy's revenue.

CONCLUSION

Xcel Energy is committed to providing our customers with safe, reliable and quality customer service. We appreciate this opportunity to report our performance to the Commission, and respectfully request that the Commission accept our Annual Report on safety, reliability, and service quality. We also request that the Commission approve our proposed reliability standards for 2024 as detailed in this Petition.

Dated: April 1, 2024

Northern States Power Company

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON SAFETY, RELIABILITY, AND SERVICE QUALITY FOR 2022; AND PETITION FOR APPROVAL OF ELECTRIC RELIABILITY STANDARDS FOR 2023

DOCKET NO. E002/M-23-73

ANNUAL REPORT AND PETITION

SUMMARY OF FILING

Please take notice that on March 31, 2023 Northern States Power Company doing business as Xcel Energy filed with the Minnesota Public Utilities Commission a Petition requesting approval of its 2022 Electric Annual Service Quality Performance Report and Petition of Northern States Power Company, requesting the Commission accept our 2022 report and approve our proposed reliability standards for 2023.

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Xcel Energy's
Service Quality Annual Report
Part II

Reliability Standards and
Request for Approval of Electric Reliability Standards for 2024

April 1, 2024
Docket No. E002/M-24-27

IV. RELIABILITY PERFORMANCE REPORT FOR 2023

Minn. R. 7826.0500 requires the Company to provide an Annual Reliability Performance Report on or before April 1 of each year reflective of our previous calendar year. The Annual Reliability Performance Report has eleven elements required by Minnesota Rules and, over time, the Commission has required the Company to report additional elements related to the Company's reliability performance. The Company's 2023 Reliability Performance Report is provided below, including the SAIDI, SAIFI and CAIDI reliability metrics as well as information about other reliability metrics the Commission has asked us to report on: MAIFI, CEMI, and CELI.

A. 2023 Reliability Performance Summary and Plans

> *The Commission's November 9, 2022 Order, Order Point 8 in Docket No. E002/M-22-162 requires the Company to provide a public facing summary and display, either directly or via a link to a PDF file, the utility's public facing summary, on the utility's website, available after a single click away from the home page.*

Consistent with Order Point 8, depicted in the Infographic provided as Attachment H and available on our website,[1] Xcel Energy served approximately 1.34 million electric customers in 2023, and our Minnesota customers had power 99.98 percent of time utilizing the Average Service Availability Index (ASAI). Excluding major event day's (MEDs), our Minnesota customers were without power for an average of 86 minutes in 2023 and experienced less than one outage. Including MEDs, less than one percent of our Minnesota customers experienced six or more power outages, with less than five percent experiencing an outage lasting twelve hours or more in 2023.

In addition, Order Point 3 in the Commission's December 12, 2014 Order in Docket No. E002/M-14-131 required the Company:

> *to augment its next filing to include a description of the policies, procedures and actions that it has implemented, and plans to implement, to assure reliability, including information on how it is demonstrating pro-active management of the system as a whole, increased reliability, and active contingency planning.*

[1] Infographic can be found on Xcel Energy's website under Outage & Safety > How We Restore Power.

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its transmission and distribution assets. We identify and implement these programs based on some of the leading causes of outages, to assure reliability, to enable proactive management of the system as a whole, and to effectively respond when outages occur. In Attachment J, the Company describes its reliability management program development consistent with Order Point 3.

Finally, in the Commission's July 17, 2023 Order in Docket No E002/GR-21-630 related to our 2022 Electric Rate Case, Order point 27(a) further required:

> *Prior to seeking future cost recovery for any incremental FLISR investments, Xcel must propose a mechanism by which to base cost recovery for FLISR investments on reliability improvements:*
>
> > *a. Xcel must track and report, beginning in its next Service Quality, Safety, and Reliability report due April 2024, on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department, indicating in the Company's safety, reliability, and service quality filings which circuits have been equipped with FLISR. Allow Xcel to modify the requirements on circuit level performance reporting in its annual Service Quality, Safety, and Reliability reports to align with the Department's recommendation.*

Fault Location, Isolation, and Service Restoration (FLISR) is a form of distribution automation that involves deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to un-faulted sections. Specifically, if there is a fault on a feeder that is automated with FLISR, we will be able reduce the number of customers who experience a sustained outage by two-thirds and will shorten the duration of certain sustained outages that affect a substantial portion of our customers. The Company provides tracking and reporting information related to its reliability performance for circuits equipped with FLISR investments in Attachment J. information requested by both Orders can be found in Attachment J.

B. Reliability Metrics Contemplated by the Commission's Rules

1. SAIDI, SAIFI and CAIDI Metrics

a. Overview of Company's SAIDI, SAIFI and CAIDI Performance

A number of state rules and Commission Orders govern our reporting on these metrics. Pursuant to Minn. R 7826.0500, Subpart 1. A-D, each utility's reliability report should include:

A. *The utility's SAIDI for the calendar year, by work center and for its assigned service area as a whole.*
B. *The utility's SAIFI for the calendar year, by work center and for its assigned service area as a whole.*
C. *The utility's CAIDI for the calendar year, by work center and for its assigned service area as a whole.*
D. *An explanation of how the utility normalizes its reliability data to account for major storms.*

In addition, as required by Minn. R. 7826.0600, on April 1, 2023, we proposed reliability standards for 2023 for each of our four Minnesota work centers based on IEEE benchmarking data.[2]

As a result, Order Point 4 in the Commission's December 5, 2023 Order in Docket No. E002/M-23-73 concluded:

> *The Commission sets Xcel Energy's 2023 statewide reliability standard at the IEEE benchmarking second quartile for large utilities; sets Xcel's Southeast and Northwest work center reliability standards at the IEEE benchmarking second quartile for medium utilities; and sets Xcel's Metro East and Metro West work center reliability center standards at the IEEE benchmarking second quartile for large utilities.*
>
> *Xcel must file a supplemental filing to its 2023 safety, service quality, and reliability report 30 days after IEEE publishes the 2023 benchmarking results.*

Table 12 below presents our 2023 reliability performance as required by Minn. R 7826.0500. Moreover, as required in the December 5, 2023 Commission Order, the Company will submit a supplemental filing after IEEE publishes its 2023 benchmarking results later this year, likely in late August or early September, along with an explanation for any statewide standards we did not meet. The remaining "Standards" column in Table 12 will be completed at that time.

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[2] The four Minnesota work centers include Metro East, Metro West, Northwest, and Southeast.

Table 12
2023 IEEE Normalized Reliability Performance Results

		Performance Results	**Standards**
Minnesota	SAIDI	86.40	--
	SAIFI	0.85	--
	CAIDI	101.56	--
Metro East	SAIDI	105.04	--
	SAIFI	0.99	--
	CAIDI	105.66	--
Metro West	SAIDI	71.41	--
	SAIFI	0.77	--
	CAIDI	92.79	--
Northwest	SAIDI	95.39	--
	SAIFI	0.90	--
	CAIDI	105.85	--
Southeast	SAIDI	87.28	--
	SAIFI	0.71	--
	CAIDI	122.43	--

The reliability statistics reported in Table 12 are calculated using the normalization method of IEEE 1366 Regional Major Event Days (MED) and include:

- Outages occurring at all levels (distribution, substation, and transmission).
- All outage cause codes.
- Where applicable, credit for partial restoration.
- Base calculations on the number of customers' billing accounts and meters.
- Base calculations on normalized data.

We determine regional MED thresholds using the IEEE 1366 method. Any day that meets or exceeds the daily SAIDI MED threshold is considered a MED for the qualifying region. This means that all outages that start on a MED (which lasts from midnight to midnight) for a particular work center are excluded from the calculation of the various reliability indices for that work center.

Order Point 19 in the Commission's December 18, 2020 Order in Docket No. E002/M-20-406 require that *"Xcel must work with the workgroup to develop an interactive map, with input from stakeholders on the scope and details of the map. Xcel must file an update on* *the development of the map by October 1, 2021.",* In compliance with Order Point 19, and in conjunction with a stakeholder workgroup, the Company developed an interactive map that contains increased granularity on certain electric reliability and service quality data, as well as low-income program participation. This map was first made available on the Xcel Energy website on April 1, 2022 and updated annually with our Service Quality Report. The data is combined with demographic data from the U.S. Census Bureau. Any Census Block with 15 or fewer Xcel Energy premises has been excluded to protect customer confidentiality and privacy. The interactive map can be accessed at the link below:[3]

Xcel Energy 2023 MN Electric Service Quality Interactive Map

Reliability statistics reported in this section are calculated using the normalization method of IEEE 1366 Regional Major Event Days (MED) and include:

- Outages occurring at all levels (distribution, substation, and transmission).
- All outage cause codes.
- Where applicable, credit for partial restoration.
- Base calculations on the number of customers' billing accounts and meters.
- Base calculations on normalized data.

We determine regional MED thresholds using the IEEE 1366 method. Any day that meets or exceeds the daily SAIDI MED threshold is considered a MED for the qualifying region. This means that all outages that start on a MED (which lasts from midnight to midnight) for a particular work center are excluded from the calculation of the various reliability indices for that work center.

> Additional reliability information was ordered in Order Point 4 in the Commission's December 12, 2014 Order in Docket No. E-002/M-14-131, which requires the Company to *"incorporate into its next filing a summary table that allows the reader to more easily assess the overall reliability of the system and identify the main factors that affect reliability."* As well as in Order Point 4(b) of the Commission's October 20, 2023 Order that requires the Company to report *"Normalized SAIDI, CAIDI, CEMI, and CELI calculated using the IEEE 2.5 base method."*

[3] https://xeago.maps.arcgis.com/apps/webappviewer/index.html?id=6b87f4d407864b939bcea05aad05bdd1

Order Point 2 in the Commission's October 20, 2023 Order within Docket No. E002/M-22-162 also requires the Company to

> *file the information listed below with its future SRSQ reports until such time as the Commission modifies the reporting requirement. Xcel shall provide the following information, as a downloadable .csv or .xlsx file, by feeder, for the calendar year. Xcel may exclude feeders that meet the 15/15 aggregation standard.*
>
> a. *Reliability reporting region where the feeder is located*
> b. *The substation the feeder is on, with its full name*
> c. *The zip code in which the feeder is primarily located*
> d. *The number of customers on the feeder, including the proportion of residential to commercial and industrial*
> e. *Whether the feeder is overhead or underground*
> f. *SAIDI, SAIFI, and CAIDI, normalized (IEEE 1366 Standard) and with Major Event Days*
> g. *Number of outages, total customer outages, and total customer-minutes-out for the following situations:*
>   i. *All levels, All Causes included,*
>   ii. *Bulk Power Supply - All causes, distribution, substation, transmission substation, and transmission line levels;*
>   iii. *All levels, no "planned" cause, includes bulk power supply*
>   iv. *All levels, "planned" cause only, includes bulk power supply."*
>
> h. *Number of outages, total customer outages, and total customer-minutes-out in the following primary outage cause categories, normalized and non-normalized*
>   i. *Equipment - OH*
>   ii. *Equipment - UG*
>   iii. *Lightning*
>   iv. *Other*
>   v. *Power Supply*
>   vi. *Planned*
>   vii. *Public*
>   viii. *Unknown*
>   ix. *Vegetation*
>   x. *Weather - non-lightning*

xi. Wildlife

Order Point 2 is addressed in the Non-Public Document, Attachment L as a live .xlsx file.

Regarding Order Point 4, Table 13 below provides a historical view of the requirements and also designates the years the Company was on (green) and off (red) target for those years/indices based on the annual rules or tariff at that time. Again, because we do not yet have 2023 targets based on the IEEE benchmarking, the Annual Rules targets are not yet included.

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Table 13

Historical Reliability Indices & Major Event Day Exclusions

All Days[1]		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Minnesota	SAIDI	116.43	184.50	214.39	141.70	125.00	124.51	134.23	130.09	184.42	168.41
	SAIFI	0.92	0.96	1.05	0.90	0.95	0.86	1.07	1.04	1.08	1.06
	CAIDI	126.00	192.32	204.84	158.10	131.22	145.30	124.88	124.66	170.24	158.81
Metro East	SAIDI	123.54	177.19	223.67	136.51	112.11	104.58	124.02	145.68	142.85	250.29
	SAIFI	0.98	1.04	1.08	0.95	0.96	0.85	1.07	1.01	1.05	1.32
	CAIDI	125.93	169.86	206.85	144.37	116.71	122.51	115.72	144.42	136.23	189.48
Metro West	SAIDI	105.98	229.78	198.25	148.58	88.23	79.93	143.90	121.33	214.14	132.33
	SAIFI	0.89	1.00	1.00	0.86	0.92	0.74	1.13	1.14	1.11	0.96
	CAIDI	118.70	229.92	198.86	173.27	95.70	107.39	127.70	106.04	193.13	138.30
Northwest[4]	SAIDI	82.82	75.61	225.74	173.71	109.50	150.83	133.58	104.05	244.83	134.22
	SAIFI	0.82	0.66	1.07	0.98	0.87	0.94	0.98	0.79	1.19	0.97
	CAIDI	101.00	115.40	211.50	177.46	126.02	160.71	135.77	131.23	205.14	138.48
Southeast[5]	SAIDI	173.45	98.23	249.05	96.37	353.32	374.20	122.56	145.09	123.52	100.94
	SAIFI	0.98	0.79	1.15	0.84	1.15	1.32	0.93	0.92	0.97	0.78
	CAIDI	176.51	125.07	217.15	114.75	307.95	283.42	132.39	157.71	126.95	130.04

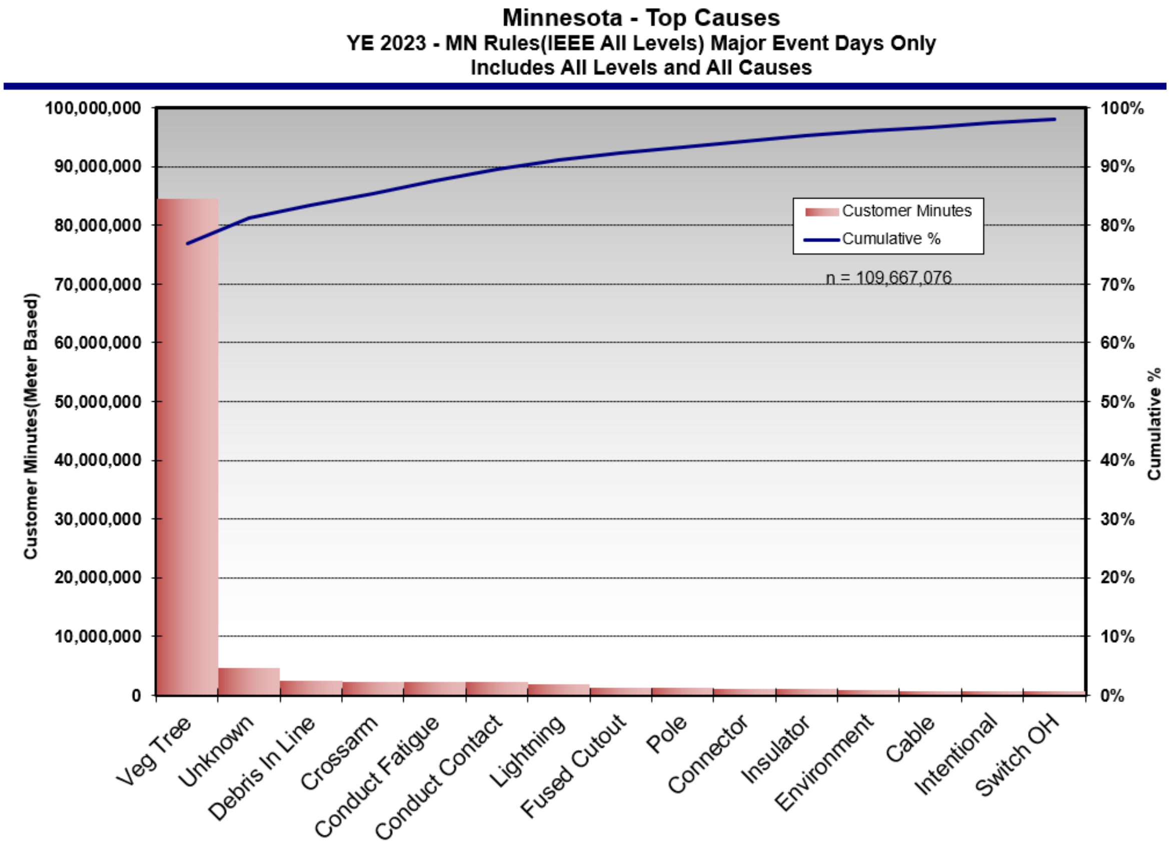
MN Tariff[2]		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	'23 Target
Minnesota	SAIDI	79.85	86.83	89.49	73.80	93.26	76.67	95.56	88.13	87.92	82.47	133.23
	SAIFI	0.78	0.79	0.81	0.72	0.85	0.70	0.96	0.90	0.84	0.81	1.21
	CAIDI	102.07	109.90	110.54	102.10	109.90	109.74	99.72	97.67	104.63	101.27	NA
Metro East	SAIDI	77.58	93.71	95.49	75.70	103.28	79.27	104.56	82.14	96.62	103.97	
	SAIFI	0.82	0.90	0.87	0.75	0.92	0.72	0.99	0.83	0.89	0.98	
	CAIDI	94.81	104.58	110.07	100.79	112.40	110.30	105.19	98.23	108.37	106.55	
		3	2	3	3	1	2	1	2	4	4	
	MED's	2/20, 6/14, 6/16	7/12, 7/18	7/5, 7/6, 7/21	6/11, 6/14, 7/12	5/24	7/15, 9/2	8/14	8/24, 9/17	5/11, 8/3, 8/27, 12/15	4/1, 7/19, 7/24, 7/26	
Metro West	SAIDI	81.85	88.98	82.90	69.28	81.25	68.25	87.51	94.64	81.22	69.76	
	SAIFI	0.82	0.82	0.82	0.70	0.84	0.69	1.02	1.05	0.86	0.75	
	CAIDI	100.15	108.90	101.51	98.40	96.63	99.17	86.17	89.82	94.52	92.80	
		1	1	3	2	1	2	4	2	4	4	
	MED's	6/14	7/18	7/5, 7/6, 7/21	6/11, 6/14	7/1	7/14, 7/15	5/29, 7/18, 8/10, 8/14	8/26, 9/17	5/11, 5/12, 8/3, 8/27	3/31, 4/1, 6/24, 6/25	
Northwest[4]	SAIDI	62.16	69.39	80.19	69.41	99.87	61.17	100.34	89.94	79.19	80.18	
	SAIFI	0.61	0.57	0.56	0.64	0.73	0.53	0.75	0.63	0.63	0.77	
	CAIDI	102.05	121.05	143.58	107.70	137.06	115.94	133.14	141.67	125.90	103.91	
		0	0	4	1	0	5	3	0	5	2	
	MED's	None	None	5/19, 6/19, 7/5, 11/18	6/11	None	4/7, 4/11, 9/2, 9/17, 12/7	3/22, 7/18, 8/23	None	1/16,5/12,5/30, 6/20, 6/24	4/1, 7/25	
Southeast[5]	SAIDI	94.45	70.78	109.59	92.84	110.67	122.22	99.65	75.28	99.26	73.60	
	SAIFI	0.67	0.52	0.82	0.79	0.77	0.84	0.76	0.66	0.78	0.62	
	CAIDI	141.93	135.23	133.06	117.19	144.04	145.19	130.48	114.54	126.96	119.40	
		4	1	3	0	2	4	1	3	1	2	
	MED's	2/20, 6/16, 8/4, 12/15	7/18	6/10, 7/5, 7/6	None	4/14, 9/20	4/10, 4/11, 7/20, 9/24	8/8	7/29, 12/15, 12/16	5/11	4/1, 7/28	

Annual Rules[3]		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	'23 Target[6]
Minnesota	SAIDI	84.00	89.95	90.45	75.04	96.07	81.02	98.95	88.99	90.00	86.40	NA
	SAIFI	0.84	0.83	0.83	0.74	0.89	0.75	0.99	0.92	0.86	0.85	NA
	CAIDI	99.67	108.09	108.93	100.90	107.39	108.29	100.27	96.29	104.05	101.56	NA
Metro East	SAIDI	79.73	93.73	95.52	76.22	103.69	80.57	104.98	82.19	96.79	105.04	TBD
	SAIFI	0.86	0.90	0.87	0.76	0.93	0.75	1.01	0.83	0.90	0.99	Late
	CAIDI	92.46	104.25	109.70	100.48	111.74	107.35	103.69	98.27	107.99	105.66	Summer
		3	2	3	3	1	2	1	2	4	4	
	MED's	2/20, 6/14, 6/16	7/12, 7/18	7/5, 7/6, 7/21	6/11, 6/14, 7/12	5/24	7/15, 9/2	8/14	8/24, 9/17	5/11, 8/3, 8/27, 12/15	4/1, 7/19, 7/24, 7/26	
Metro West	SAIDI	83.02	90.95	83.64	69.51	83.26	69.50	88.86	94.73	81.85	71.41	TBD
	SAIFI	0.84	0.84	0.82	0.71	0.87	0.70	1.00	1.06	0.87	0.77	Late
	CAIDI	98.50	108.44	101.43	97.84	95.47	99.16	88.51	89.67	94.19	92.79	Summer
		1	1	3	2	1	2	4	2	4	4	
	MED's	6/14	7/18	7/5, 7/6, 7/21	6/11, 6/14	7/1	7/14, 7/15	7/18, 8/10, 8/14, 10/20	8/26, 9/17	5/11, 5/12, 8/3, 8/27	3/31, 4/1, 6/24, 6/25	
Northwest[4]	SAIDI	82.80	75.58	85.81	75.77	109.34	89.07	121.97	93.46	84.06	95.39	TBD
	SAIFI	0.82	0.66	0.70	0.76	0.87	0.78	0.93	0.74	0.69	0.90	Late
	CAIDI	101.02	115.39	122.38	100.28	126.05	113.48	130.98	126.13	122.38	105.85	Summer
		0	0	5	1	0	3	1	1	5	1	
	MED's	None	None	5/19,6/19,7/5, 7/16, 11/18	6/11	None	1/26, 4/11, 9/2	7/18	8/29	1/16,5/12,5/30, 6/20, 6/24	7/25	
Southeast[5]	SAIDI	103.45	86.51	110.23	96.33	118.80	129.11	105.19	79.94	111.84	87.28	TBD
	SAIFI	0.80	0.75	0.85	0.84	0.92	0.93	0.87	0.76	0.91	0.71	Late
	CAIDI	129.20	115.16	130.02	114.73	129.64	139.00	120.29	105.09	122.69	122.43	Summer
		4	1	3	0	2	4	1	3	1	1	
	MED's	2/20, 6/16, 8/4, 12/15	7/18	6/10, 7/5, 7/6	None	4/14, 9/20	4/10, 4/11, 7/20, 9/24	8/8	7/29, 12/15, 12/16	5/11	7/28	

1) All Days - Includes All Days, Levels and Causes, Meter-based customer counts
2) MN Tariff - Normalized using IEEE 1366 at the Regional level after removing Transmission Line level. All Causes, Meter-based customer counts
3) Annual Rules - Normalized using IEEE 1366 at the Regional level, All Levels, All Causes, Meter-based customer counts
4) Northwest - Includes customers counts and interruptions in the North Dakota work region that impact Minnesota customers
5) Southeast - Includes customers counts and interruptions in the South Dakota work region that impact Minnesota customers
6) 2012-2020 Annual Rules Targets were based on 5 year rolling actual averages or locked targets.
2021 Annual Rules Targets are based on IEEE Working Group Benchmarking study Large Utility Group 2nd Quartile for Metro East & West
Medium Utility Group 2nd Quartile for Northwest & Southeast, Current year targets will become available late summer when study results are released

Given the difficulty of conveying both reliability and factors that affect reliability in a single table, we have separated these out. Graph 1 below illustrates the major causes of outages for storm days that affect reliability. These types of outages are the main factors that affect reliability. Graphs 1A-1D provide the percentage of customer interruptions by various outage categories for each work center. Results in all graphs are presented using Annual Rules storm normalization and all-days (no normalization). Please see Attachment K for the underlying data for Graphs 1A – 1D.

Graph 1
Major Cause of Outages



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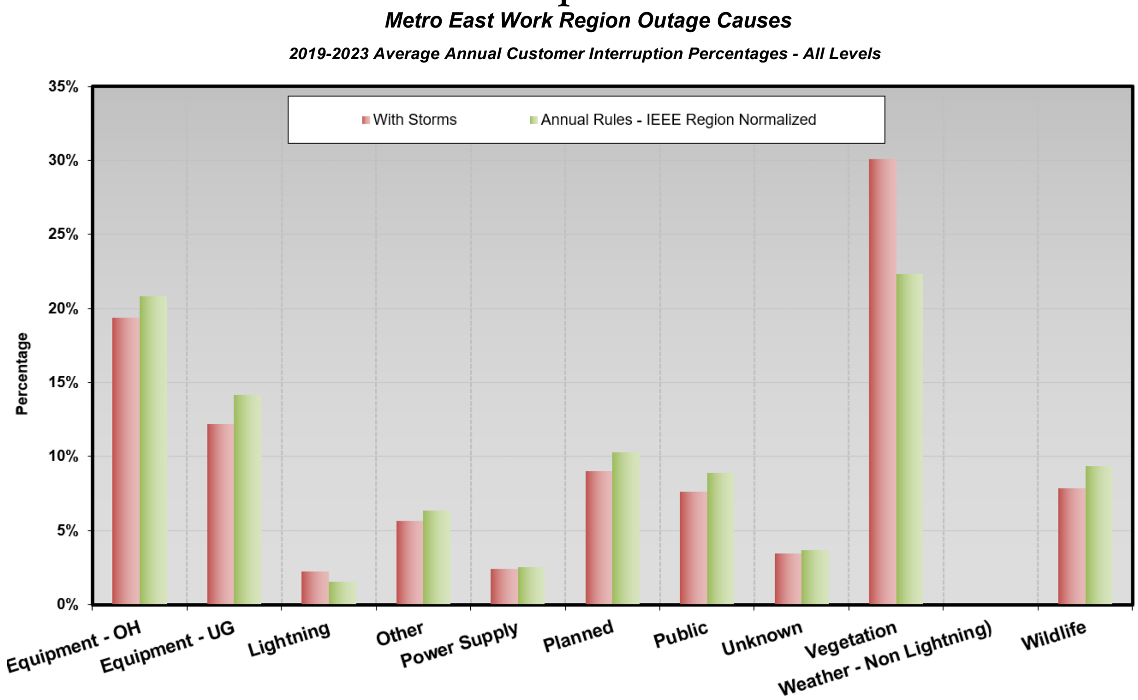
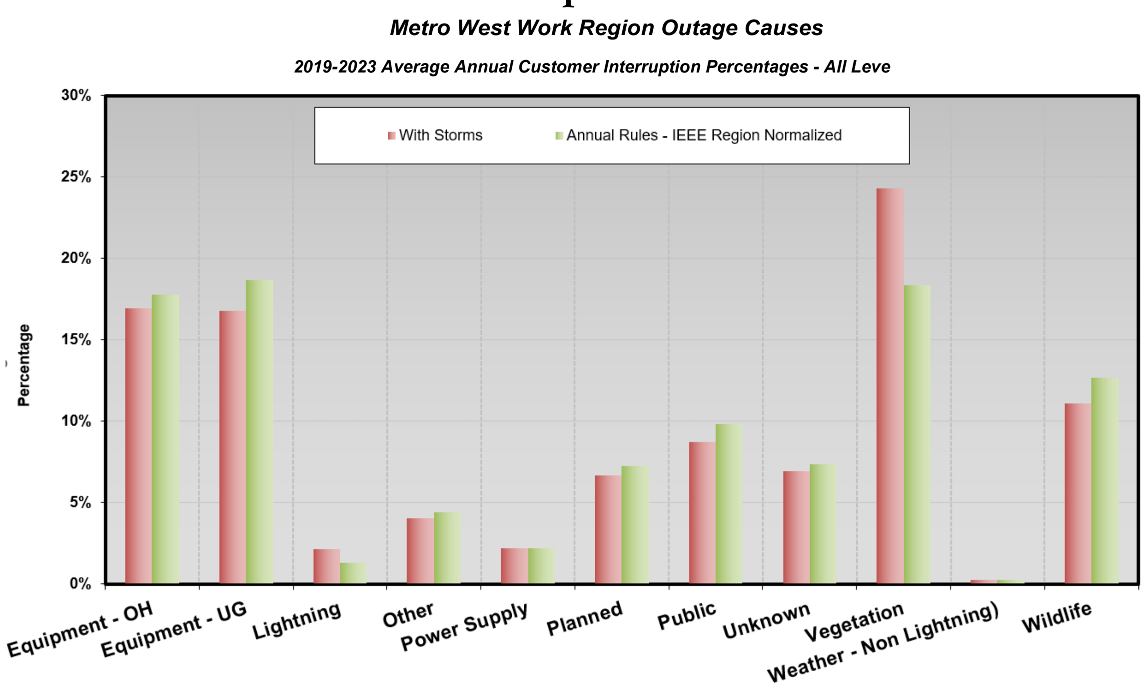
Graph 1A



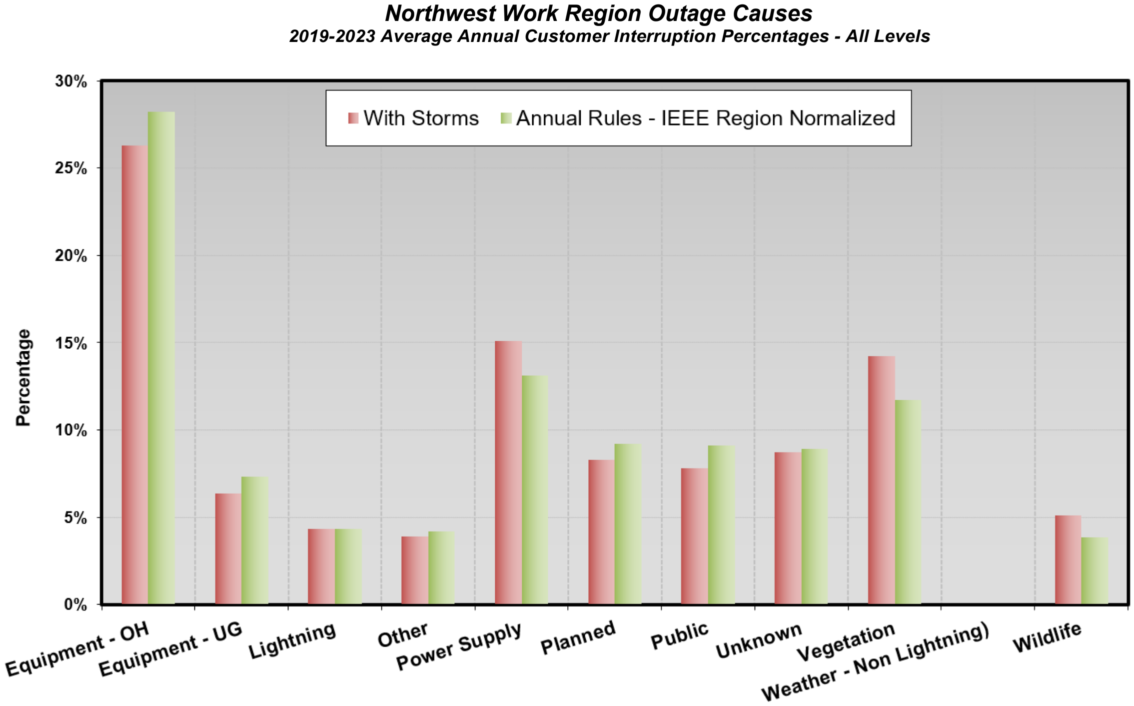
Annual Rules based on sustained outages (>5 minutes), including All Levels and All Cause codes, IEEE 1366 Region normalized using 5 year rolling data including outliers

Graph 1B



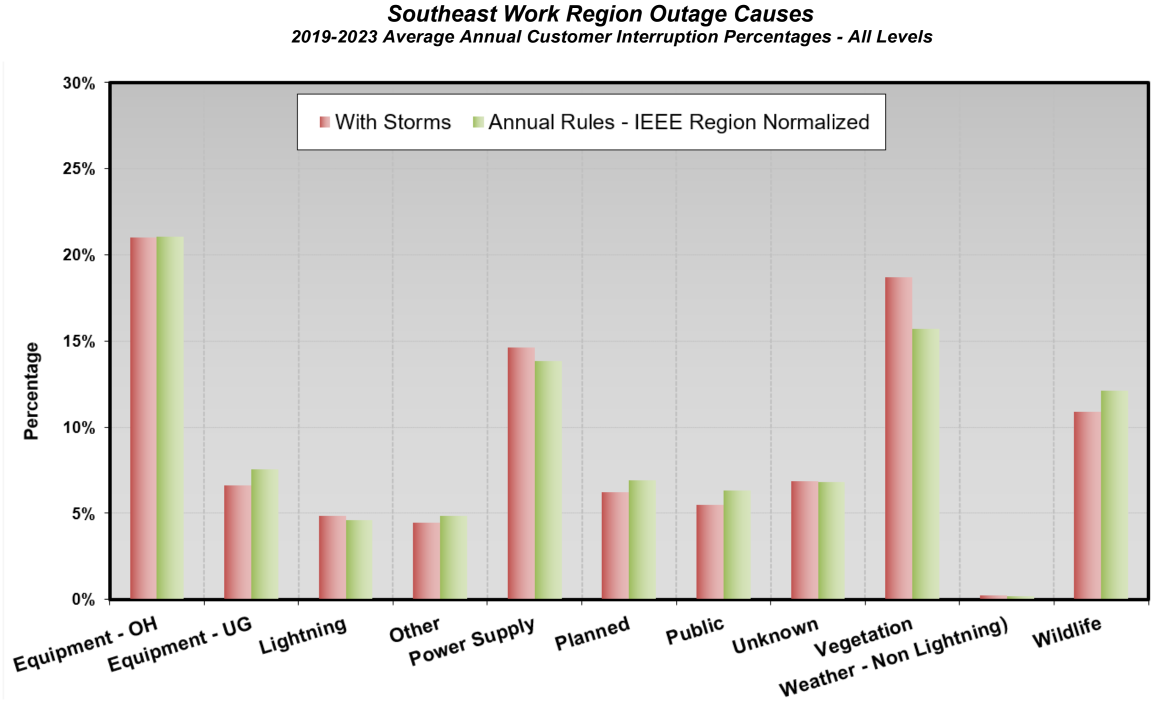
Annual Rules based on sustained outages (>5 minutes), including All Levels and All Cause codes, IEEE 1366 Region normalized using 5 year rolling data including outliers

Graph 1C



Annual Rules based on sustained outages (>5 minutes), including All Levels and All Cause codes, IEEE 1366 Region normalized using 5 year rolling data including outliers. Southeast Region includes customers/outages in the South Dakota work region that are in the state of Minnesota.

Graph 1D



Reliability Management Programs are developed to address major causes of outages and are discussed in Attachment K. In 2023, as seen in Graph 1 above, vegetation related causes accounted for the most customer outage minutes. Our Vegetation Management Program remains a highly valued program because it can impact outages during storms, in particular. It addresses service line debris clearance, an inspection program, and landscape maintenance around overhead lines. Tree pruning, part of landscape maintenance, is the selective removal of branches that pose an unacceptable safety or reliability risk to the conductors or equipment currently based on prior tree contact or inspection. The overall goal of our Vegetation Management Program is to maintain an approximate five-year cycle of continual vegetation maintenance. Additional Reliability Management Program summaries can be found in Attachment J.

> *The Commission's December 5, 2023 Order, Order Point 4(i), in Docket No. E002/M-22-162 requires the Company to provide reliability metrics by customer class or if that information is not available, a timeline by which the Company will be able to provide such data.*

Table 13A provides the information requested in Order Point 4 of the December 5 Order referenced above.

Table 13A

2023 Reliability Indices By Customer Class					
Annual Rules		Residential	Commercial	Industrial	All
Minnesota	SAIDI	89.1	75.4	68.3	86.4
	SAIFI	0.88	0.75	0.69	0.85
	CAIDI	101	100	100	102

Table 13A provides the SAIDI, SAIFI, and CAIDI metrics for residential, commercial, and industrial customers. As this is only the second year we have been able to calculate metrics by customer class, the Company continues to work to fully understand the causes and differences between customer class and reliability results. Although not formally studied, the difference between feeders primarily serving commercial versus residential customers is likely due to less vegetation in industrial and commercial areas, shorter feeders due to higher load density resulting in less exposure to the environment, and a higher percentage of customers with underground service. We note that Attachment L provides customer class information along with the reliability data by feeder. The Company will continue to research and determine differences in reliability results between customer classes and report on any insights gained in future service quality reports.

Much of the data in Attachment L has been marked as protected data. This information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). As we have explained in past filings related to our treatment of customer data, we take our responsibility for all the data we maintain in order to provide our customers with reliable and safe service very seriously. Nearly daily, we hear about data breaches impacting individuals and organizations. Responsible access to sensitive data must be balanced with accountability for third parties to demonstrate their actions with the data will be in the public interest before gaining access. Additionally, as we have pointed out in the past with respect to utility release of customer data, once released by the utility, the Commission will have no jurisdiction over third parties, and the utilities lose any ability to control its use, sale, or other dissemination.

Our Company principles with respect to privacy and security are:

- Maintain customer privacy, confidentiality, and security in terms of their usage and how they are connected to the grid, and
- Avoid revealing details that would give a bad actor information to target an attack for maximum impact (ex. Peak load, equipment capacities, number of customers, how critical infrastructure is connected to the grid, etc.).

Attachment L to this filing contains information that the Company believes could be manipulated to reveal the location and size of facilities serving our customers. The public disclosure or use of this information creates a risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our filing.

a. Additional contemplated SAIDI, SAIFI, and CAIDI metrics based on grid modernization investments

Order Point 5 of the Commission's December 18, 2020 Order in Docket No. E002/M-20-406 required the Company to "file the reliability (SAIDI, SAIFI, CAIDI, MAIFI, normalized/nonnormalized) for feeders with grid modernization investments such as Advanced Metering Infrastructure or Fault Location Isolation and Service Restoration to the historic five-year average reliability for the same feeders before grid modernization investments."

Like the Commission, the Company is interested in realizing the reliability improvements gained through grid modernization efforts. As part of the deployment of Advanced Distribution Management System (ADMS) to the Minnesota Distribution Control Centers, the Company installed automated field devices on three feeders that were used to test the functionality of FLISR. These automated field devices are integrated with ADMS and are currently running what is referred to as Open Loop FLISR, or a mode that is supervised and controlled by control center operators. The Company will be expanding the initial test area and feeders with enabled fault location prediction. Included in this expansion, the Company has developed a 2021-2027 deployment plan and proceeded to implement expansion of the FLISR footprint. It is expected to result in reliability improvements in the future with footprint expansion and utilizing fault location functionality within ADMS. Included in Attachment J we summarize FLISR reliability results.

Advanced Metering Infrastructure (AMI) is expected to provide improvements that will give the Company insight into customers' outages sooner. In 2022, the Company began integration between AMI and the outage management system. Integration efforts are continuing into 2024. This integration merges real-time AMI data and capabilities into the outage management system to enhance outage detection, accelerate outage response, and reduce truck rolls. AMI data such as last gasp, power restoration, and ping responses will be leveraged to enhance our response to outages and improve reliability performance. However, it should be noted that because AMI technology provides enhanced capabilities, creating more accurate outage start and completion times, this will likely reflect as a decline of our reported reliability metrics as compared to our historical reporting. In addition, reliability performance for individual feeders and non-normalized reliability metrics can fluctuate greatly year-to-year based on a number of factors, including severity of weather and an improving or declining reliability performance. In considering any metric that measures the impact of grid modernization investments, it is important to note that reliability improvements are expected to be gradual rather than a step change.

2. Action Plan for Failures to Comply by Work Center

a. Reliability Performance as Compared to Standards

Minn. R. 7826.0500 subpart 1.E requires the Company to provide *"[a]n action plan for remedying any failure to comply with the reliability standards set for in Minn R. 7826.0600 or an explanation as to why non-compliance was unavoidable."*

On April 1, 2024, as required by Minn. R. 7826.0600, we proposed 2024 reliability standards for our MN service territory and each of our four Minnesota work centers. We note that these reliability statistics are calculated using the normalization method of IEEE 1366 (2.5 base method) Regional Major Event Days (MED).

- Include outages occurring at all levels (distribution, substation, and transmission).
- Include all outage cause codes.
- Where applicable, include credit for partial restoration.
- Base calculations on the number of customers' billing accounts and meters.
- Base calculations on normalized data

Again, because this Order Point relies on the IEEE Benchmarking results, which we will not receive until later this year, we will fully respond as part of the supplemental filing in late August or early September, when the Company will provide any explanations and/or action plans for any failures to meet the IEEE Benchmarking results.

In addition, Order Point 4 of the Commission's October 20, 2023 Order requires the Company to:

> *provide in future annual SRSQ reports…until such time as the Commission modifies the reporting requirement:*

a. *Non-normalized SAIDI, SAIFI and CAIDI values*
b. *Normalized SAIDI, CAIDI, CEMI, and CELI calculated using the IEEE 2.5 base method;*
c. *Non-normalized and normalized MAIFI information;*
d. *ERT information within -90 minutes to 0 and within +1 to +30 minutes;*
e. *Non-normalized and normalized CEMI at outage levels of 4, 5, and 6 interruptions;*
f. *Highest number of interruptions experienced by one customer.*
g. *Non-normalized and normalized CELI at outage duration of greater than 6, 12, and 24 hours;*
h. *Longest interruption experienced by one customer;*
i. *Performance and reliability factors by customer class;*
j. *Field office personnel information which includes the number of contractors by work center, and*
k. *Causes of sustained customer outages, by work center.*

Order Points 4(a) – 4(j) are documented and discussed throughout Part II. Regarding Order Point 4(k) of the October 2023 Order, subparts 1-4 below provide the requested information. As set forth in Section B above, we determine regional major event day thresholds based on using the IEEE 1366 normalization method.

For 2023, we used the following IEEE MED threshold calculation procedures:

- Using the previous five years of outage history for each region, we:
  - Calculate the daily SAIDI;
  - Calculate the Natural Log of each daily SAIDI; and
  - Calculate the Average and Standard Deviation of the Natural Logs.
- Based on the above methodology, IEEE 1366 sets a unique Major Event Day (MED) threshold for each region. A MED is defined as any day meeting or exceeding the MED SAIDI threshold, which is set at the exponent of the average plus 2.5 standard deviations of the Natural Logs.

As part of the supplemental filing in late August or early September, the Company will provide any explanations and/or action plans for any failures to meet the IEEE Benchmarking results.

Order Point 3 of the Commission's December 12, 2014 Order in Docket No. E002/M-14-131 required the Company *"to augment its next filing to include a description of the policies, procedures and actions that it has implemented, and plans to implement, to assure* *reliability, including information on how it is demonstrating pro-active management of the system as a whole, increased reliability, and active contingency planning."*

In accordance with Order Point 3 in the Commission's December 12, 2014 Order in Docket No. E-002/M- 14-131, our Reliability Management Program, as summarized in Attachment J, focuses on reviewing outage data, including the items highlighted by work center below, and identifying improvement opportunities through several methods including our Feeder Performance Improvement Program, vegetation management, proactive cable replacements and substation and transformer breaker assessments. The Company will continue our ongoing assessments of reliability and asset health, seeking to implement additional programs that will allow for system improvements and maintenance to achieve the largest improvements in reliability measurements. We are committed to providing reliable service to our customers and discuss the reliability performance of the specific work centers below.

1. Metro East

In Graphs 2, 3, and 4, we show the five-year trend of all three indices. Table 14 shows the top level and cause of outages from the current year that deviated higher and lower than the previous five-year average.

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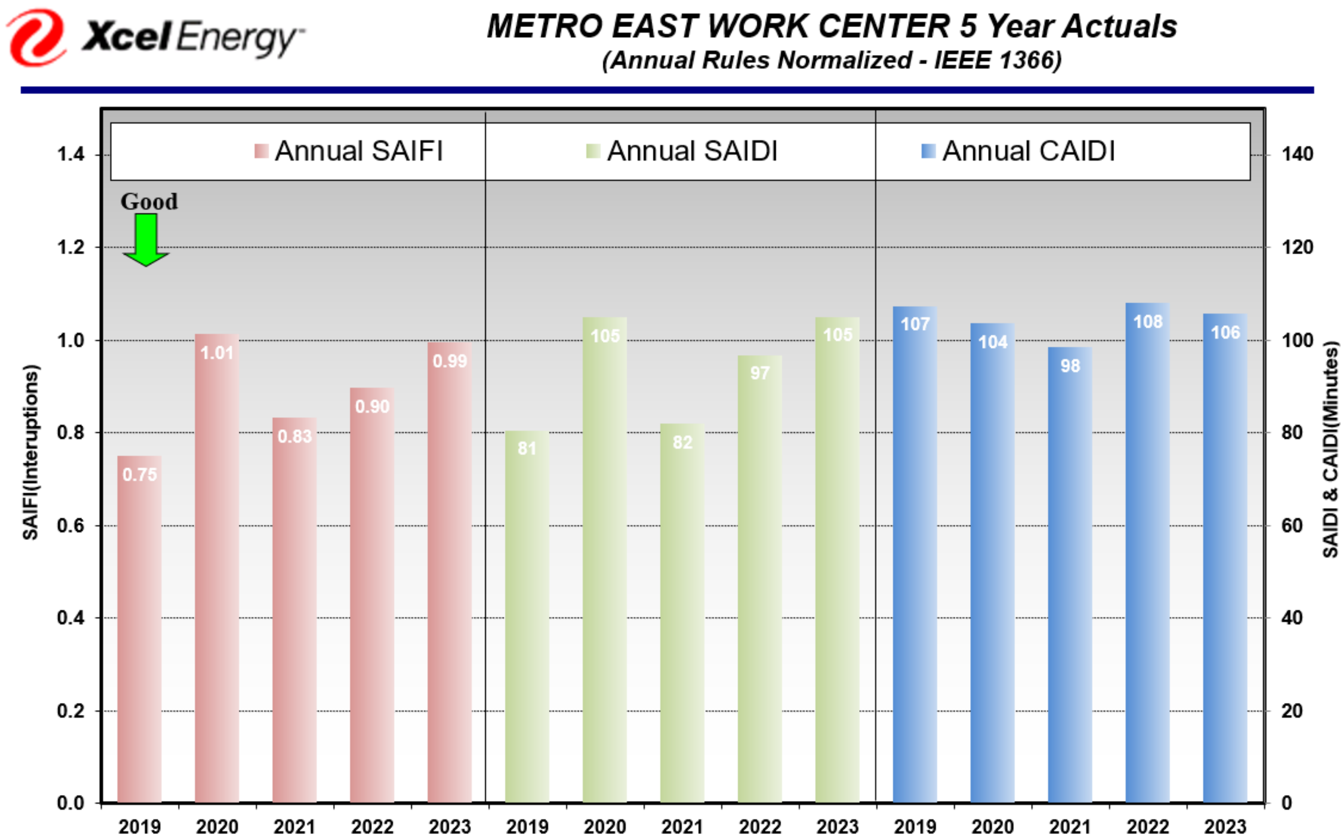
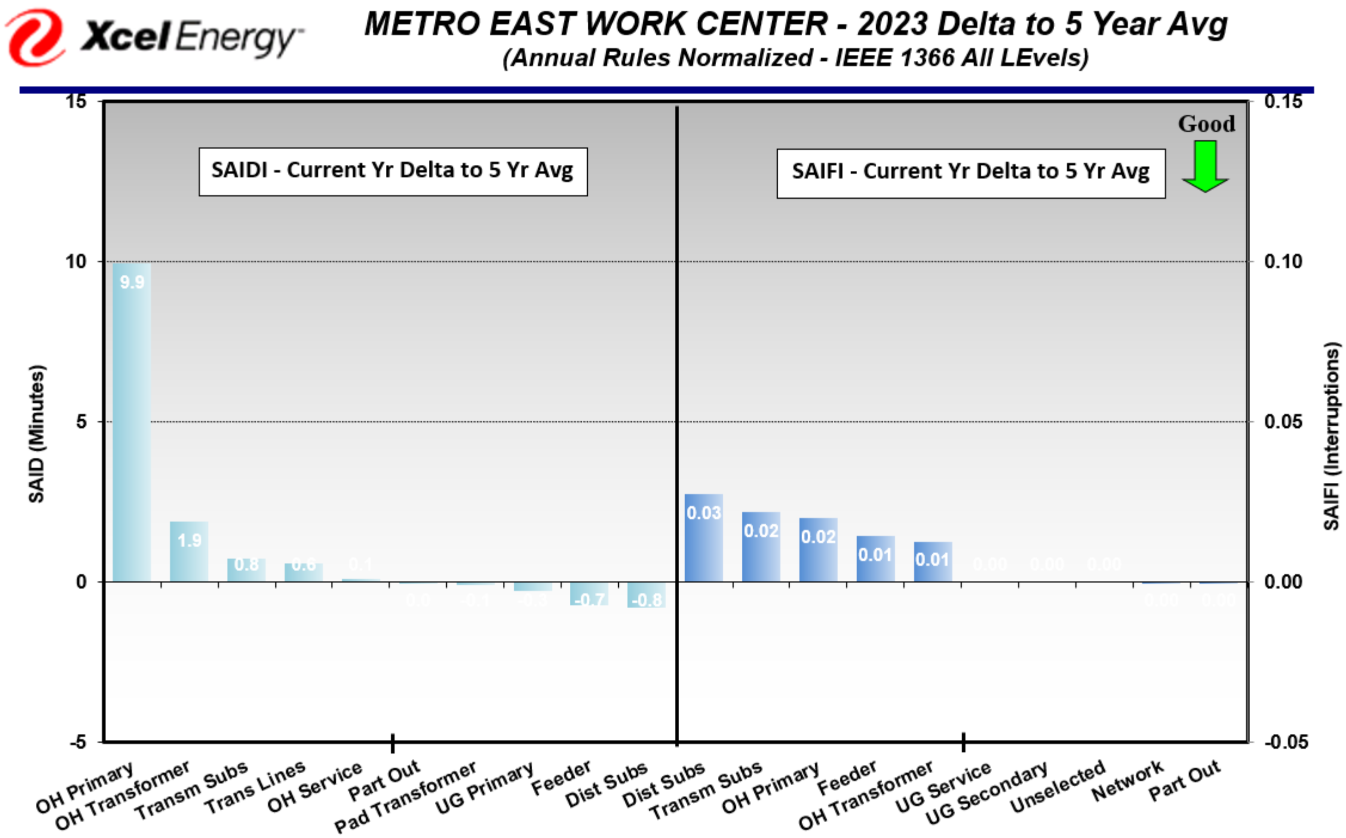
Graph 2



GRAPH 3


Xcel Energy
METRO EAST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
15
10
5
0
-5
0.15
0.10
0.05
0.00
-0.05
9.9
1.9
0.8
0.6
-0.7
-0.8
0.03
0.02
0.02
0.01
0.01
OH Primary
OH Transformer
Transm Subs
Trans Lines
OH Service
Part Out
Pad Transformer
UG Primary
Feeder
Dist Subs
Dist Subs
Transm Subs
OH Primary
Feeder
OH Transformer
UG Service
UG Secondary
Unselected
Network
Part Out

GRAPH 4

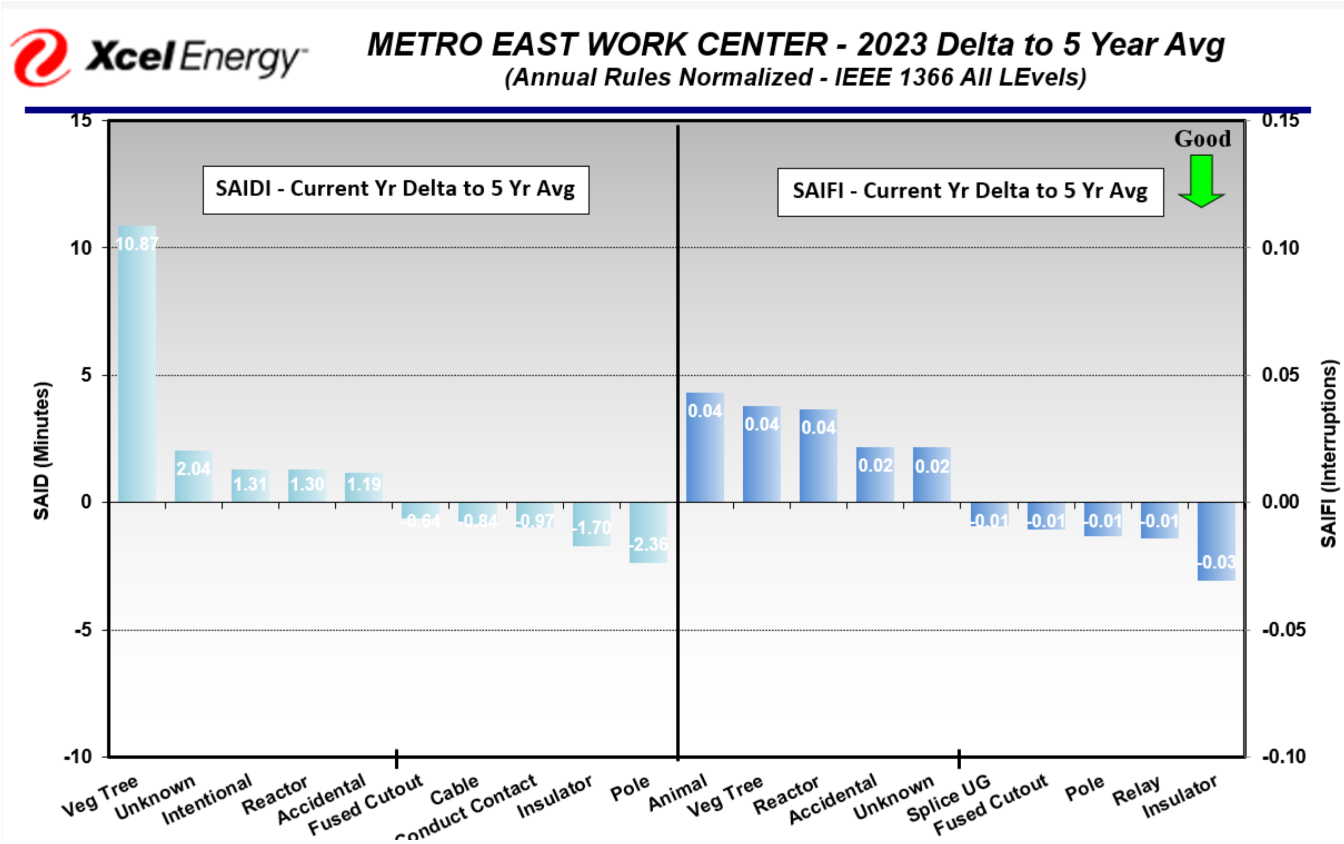

Xcel Energy
METRO EAST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
15
10
5
0
-5
-10
0.15
0.10
0.05
0.00
-0.05
-0.10
10.87
2.04
1.31
1.30
1.19
-0.64
-0.84
-0.97
-1.70
-2.36
0.04
0.04
0.04
0.02
0.02
-0.01
-0.01
-0.01
-0.01
-0.03
Veg Tree
Unknown
Intentional
Reactor
Accidental
Fused Cutout
Cable
Insulator
Pole
Animal
Veg Tree
Reactor
Accidental
Unknown
Splice UG
Fused Cutout
Pole
Relay
Insulator

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Table 14
Metro East Top Level Outage Causes

Impact events / days

Major Event Days - Excluded from normalized results

Date	SAIDI	SAIFI	CAIDI	Reason
4/1	97.1	0.17	578	High winds/snow/ice. Tree contacts & equipment failures
7/19	32.5	0.09	381	High winds/thunderstorms. Tree contacts
7/24	7.9	0.04	219	High winds/thunderstorms. Tree contacts & equipment failures
7/26	7.5	0.04	203	High winds/thunderstorms. Tree contacts & lightning strikes

Moderate Storm Activity

Date	SAIDI	SAIFI	CAIDI	Reason
1/4	1.7	0.01	138	High winds/snow/ice. Tree contacts
3/31	4.9	0.01	768	High winds/snow/ice. Tree contacts
6/24-25	2.8	0.01	202	High winds/thunderstorms. Tree contacts & equipment failures
7/4	2.1	0.02	115	High winds/thunderstorms. Tree contacts
7/20	2.0	0.01	216	High winds/thunderstorms. Tree contacts
7/27-28	3.9	0.03	151	High winds/thunderstorms. Tree contacts
8/11	4.0	0.05	76	High winds/thunderstorms. Tree contacts & substation/transmission events
9/29	5.0	0.04	138	High winds/thunderstorms. Tree contacts & lightning strikes
10/4	2.0	0.02	108	High winds/snow/sleet. Tree contacts & equipment failures.

Transmission

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
2/1	0.9	0.02	36	Hugo / Lino Lakes	Accidental - Maintenance error
8/11	0.7	0.01	76	Lindstrom / Chisago Lakes	Equipment failure - Transformer
9/29	0.4	0.01	40	Lindstrom/Scandia	Lightning strike on transmission line

Distribution Substation

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
5/31	0.3	0.01	24	Saint Paul / Cottage Grove	Animal contact in the distribution substation
6/18	0.4	0.03	15	West & South Saint Paul	Animal contact in the distribution substation
8/11	1.3	0.04	36	Saint Paul / Maplewood	Equipment failure - Substation reactor
9/26	0.3	0.00	115	Empire / Farmington	Equipment failure - Fuse link
11/15	0.2	0.02	12	W St Paul / Mendota Hghts	Accidental - Switching error

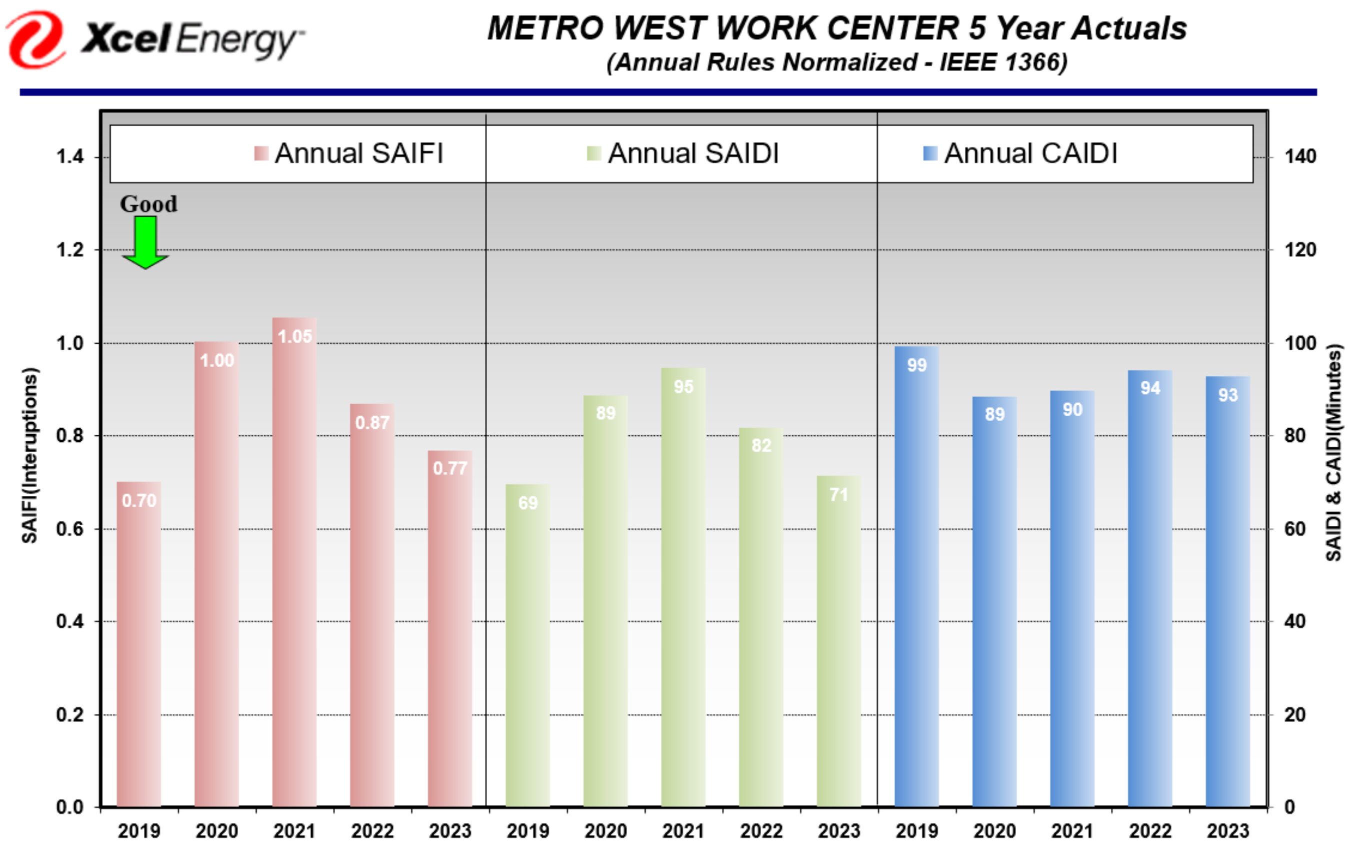
Distribution Lines

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
8/10	1.3	0.01	149	Lino Lakes/ Shoreview	Equipment failure - Line connector
8/10	1.3	0.01	141	Lino Lakes / Blaine	Equipment failure - Line connector
10/9	1.2	0.00	277	Inver Grove Heights	Equipment failure - Underground splice
8/6	1.1	0.00	526	Stillwater/May Twp	Tree contact - Rainy conditions
8/6	0.9	0.01	162	Woodbury	Equipment failure - Cable
10/2	0.9	0.00	434	Marine Saint Croix	Tree contact - Branch on wire
9/20	0.8	0.00	242	Mounds View	Public vehichle hit and damaged poles
9/29	0.8	0.01	158	Saint Paul	Lightning strike to mainline
7/21	0.8	0.00	232	Saint Paul	Public vehichle hit and damaged poles
6/1	0.8	0.01	132	Saint Paul	Accidental - Dig in to cable

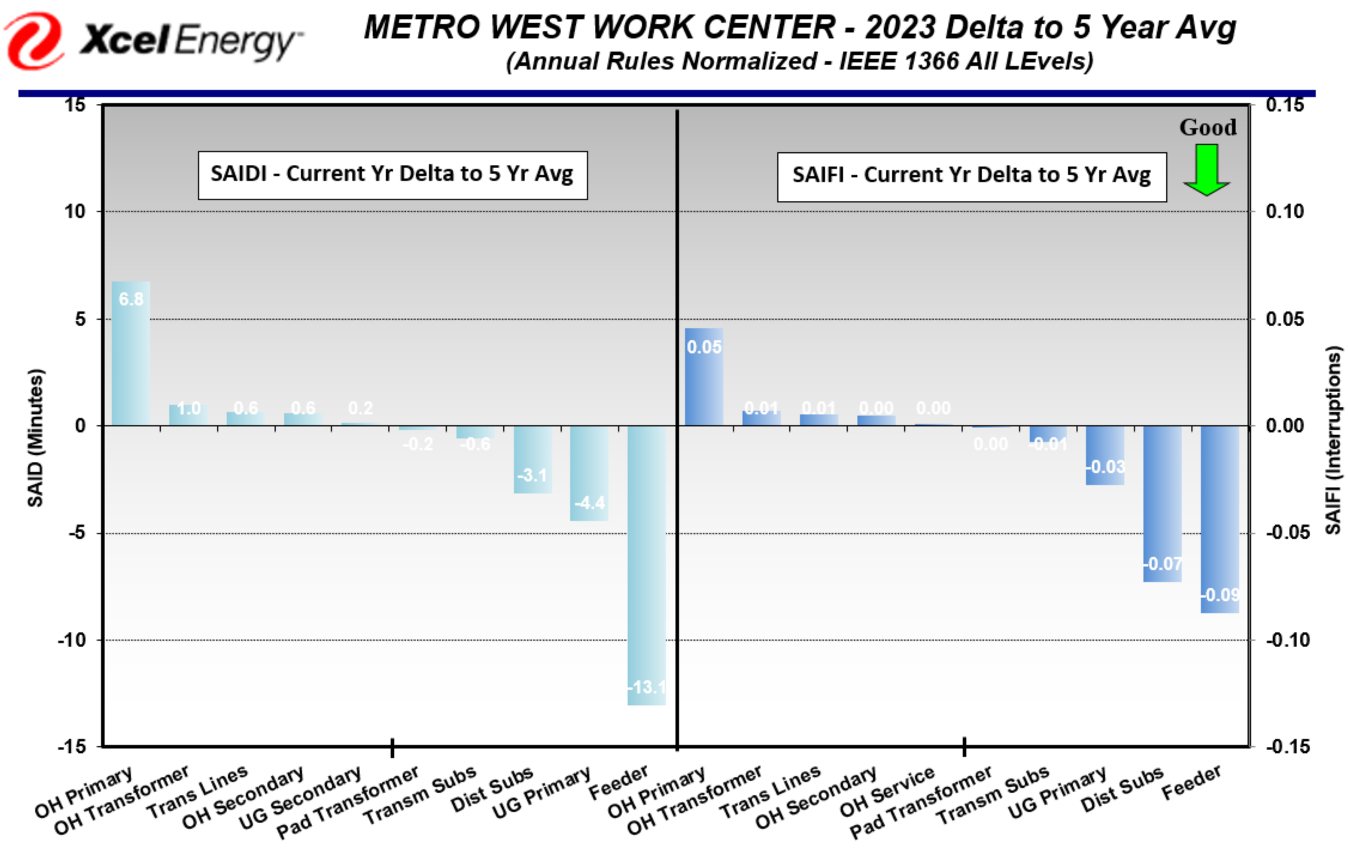
2. Metro West

Graphs 5, 6, and 7 show the five-year trend of all three indices, and Table 15 illustrates the top level and cause of outages from the current year that deviated higher and lower than the previous five-year average.

Graph 5



Graph 6


Xcel Energy
METRO WEST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
15
10
5
0
-5
-10
-15
0.15
0.10
0.05
0.00
-0.05
-0.10
-0.15
6.8
1.0
0.6
0.6
0.2
-0.2
-0.6
-3.1
-4.4
-13.1
0.05
0.01
0.01
0.00
0.00
0.00
-0.01
-0.03
-0.07
-0.09
OH Primary
OH Transformer
Trans Lines
OH Secondary
UG Secondary
Pad Transformer
Transm Subs
Dist Subs
UG Primary
Feeder
OH Primary
OH Transformer
Trans Lines
OH Secondary
OH Service
Pad Transformer
Transm Subs
UG Primary
Dist Subs
Feeder

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Graph 7

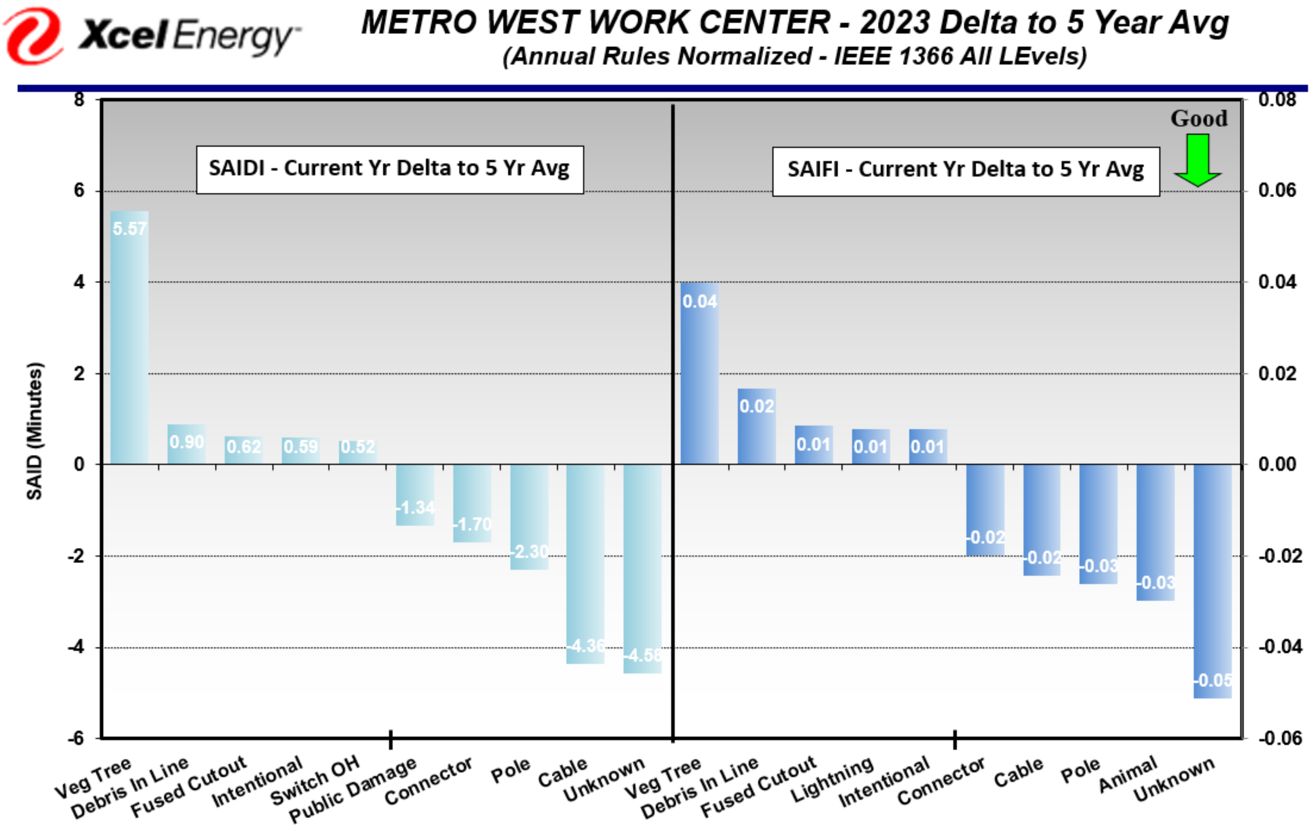

Table 15
Metro West Top Level Outage Causes

Impact events / days

Major Event Days - Excluded from normalized results

Date	SAIDI	SAIFI	CAIDI	Reason
3/31	15.9	0.03	497	High winds/snow/ice. Many tree contacts & equipment failures
4/1	28.3	0.06	476	High winds/snow/ice. Many tree contacts & equipment failures
6/24	11.5	0.05	225	High winds/thunderstorms. Many tree, lightning strikes, & equipment failures.
6/25	4.8	0.04	112	High winds/thunderstorms. Many tree, lightning strikes, & equipment failures.

Moderate Storm Activity

Date	SAIDI	SAIFI	CAIDI	Reason
6/10	1.1	0.01	114	High winds/thunderstorms. Tree contacts
6/23	1.1	0.01	77	High winds/thunderstorms. Tree contacts
7/19	3.2	0.02	141	High winds/thunderstorms. Tree contacts & equipment failures
7/26	4.0	0.02	243	High winds/thunderstorms. Tree contacts & lightning strikes
7/28	2.1	0.02	122	High winds/thunderstorms. Tree contacts
9/29-30	2.2	0.02	135	High winds/thunderstorms. Tree contacts & equipment failures
10/4	1.9	0.01	184	High winds/thunderstorms. Tree contacts

Transmission

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
5/12	1.6	0.02	104	Mound / Wayzata	Lightning strike on transmission line
8/16	0.0	0.00	15	Minnetonka / Hudson	Equipment Failure - Voltage regulator
10/3	0.0	0.00	64	Franklin	Tree contact on transmission line

Distribution Substation

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
5/21	0.1	0.01	26	Brooklyn Park / Osseo	Animal contact in the distribution substation
6/22	0.2	0.01	29	Mound / Wayzata	Animal contact in the distribution substation

Distribution Lines

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
10/3	0.9	0.00	556	Minnetrista	Tree contact - Windy conditions
9/23	0.7	0.01	111	Minneapolis	Equipment failure - Overhead switch
2/13	0.6	0.00	133	Savage / Burnsville	Public vehichle hit and damaged pole
7/26	0.5	0.00	579	Brooklyn Park	Equipment failure - Underground splice
7/8	0.4	0.00	109	Brooklyn Park / Center	Equipment failure - Cable mainline
7/19	0.4	0.00	87	Columbia Heights / Fridley	Tree contact - Thunderstorm conditions
10/4	0.4	0.00	504	Richfield	Tree contact - Windy conditions
5/25	0.4	0.01	57	Columbia Heights / Fridley	Public vehichle hit and damaged pole
8/2	0.4	0.00	249	Saint Anthony	Tree contact - Windy conditions
8/2	0.2	0.00	247	Eden Prairie	Accidental - Crew droped line in wires

3. Northwest

Graphs 8, 9, and 10 show the five-year trend of all three indices, and Table 16 illustrates the top level and cause of outages from the current year that deviated higher and lower than the previous five-year average.

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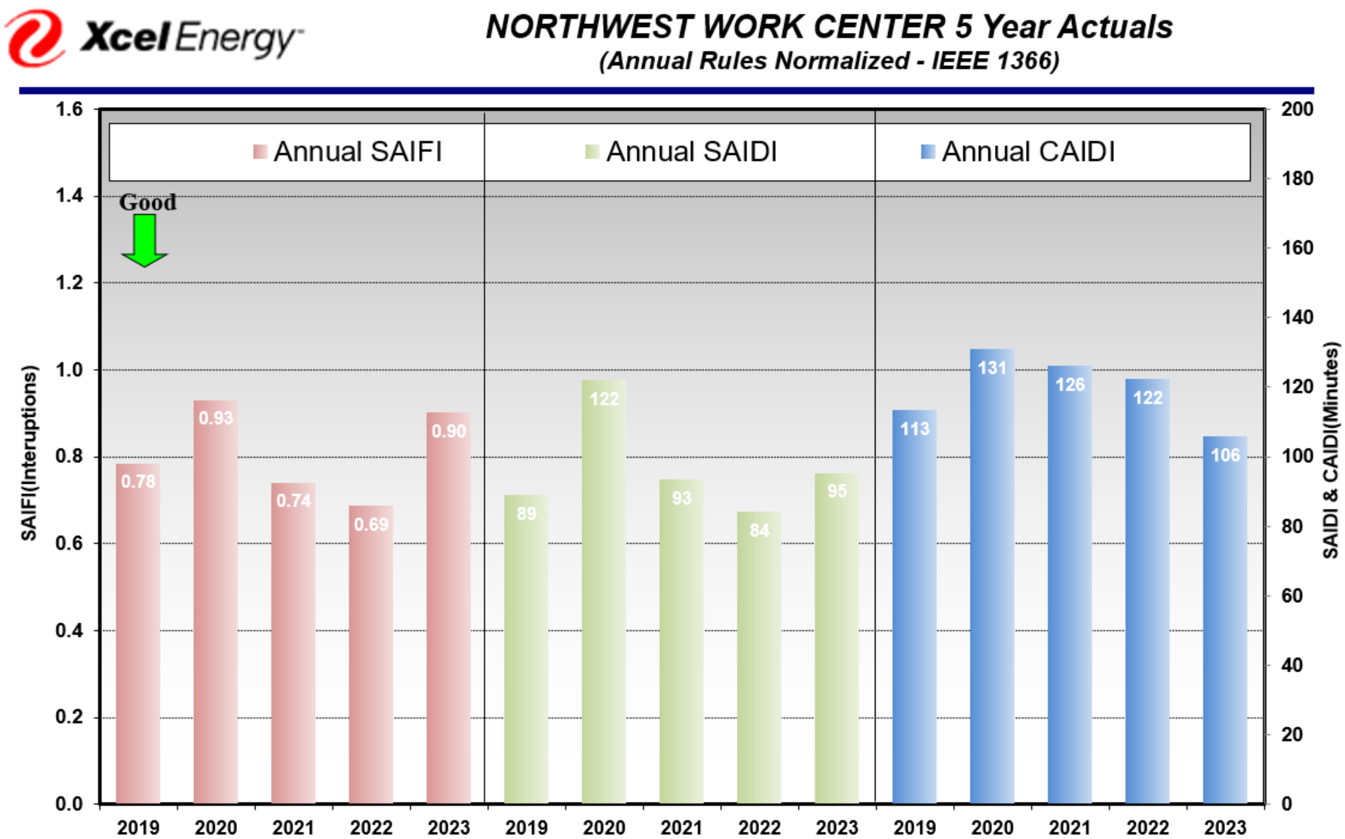
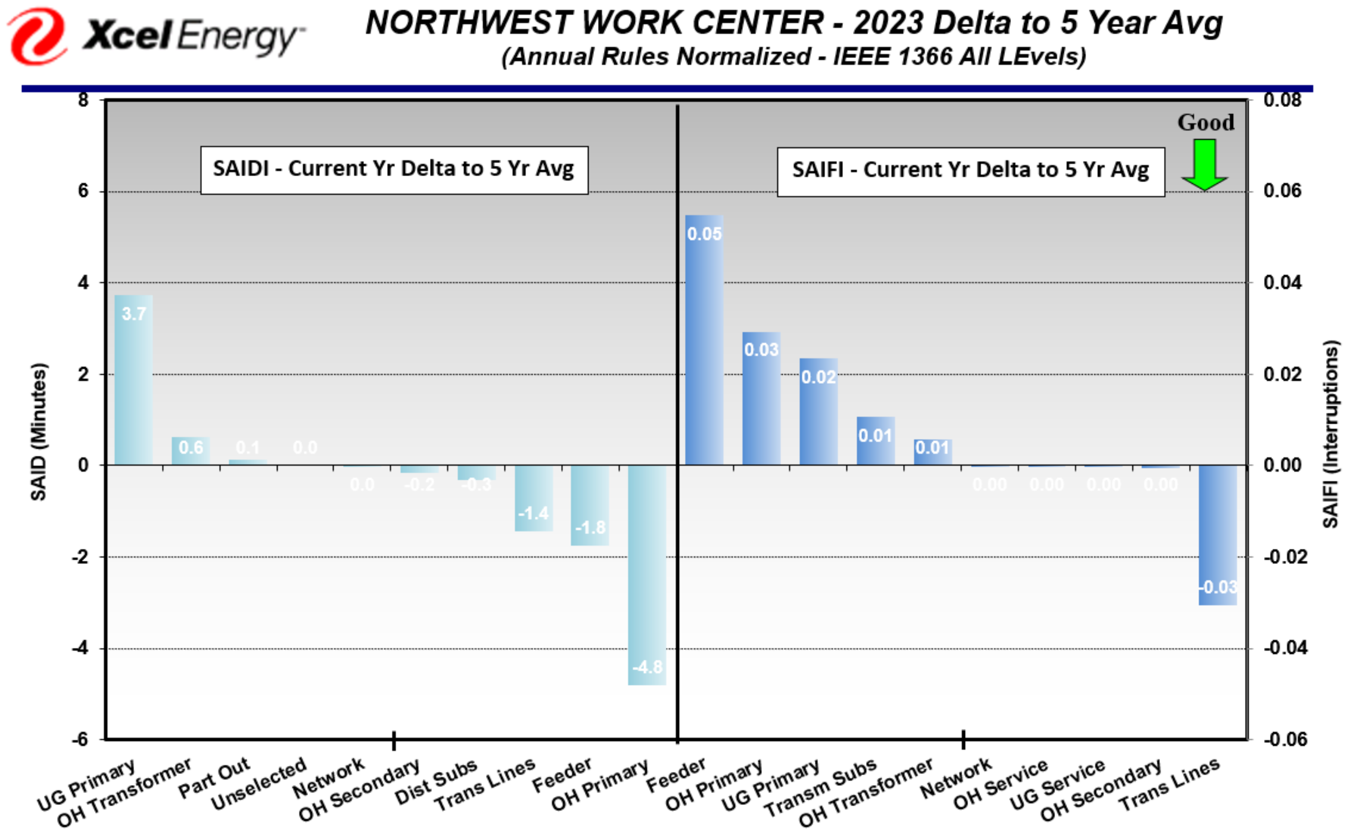
Graph 8



Graph 9


Xcel Energy
NORTHWEST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
3.7
0.6
0.1
0.0
0.0
-0.2
-0.3
-1.4
-1.8
-4.8
0.05
0.03
0.02
0.01
0.01
0.00
0.00
0.00
0.00
-0.03
UG Primary
OH Transformer
Part Out
Unselected
Network
OH Secondary
Dist Subs
Trans Lines
Feeder
OH Primary
Feeder
OH Primary
UG Primary
Transm Subs
OH Transformer
Network
OH Service
UG Service
OH Secondary
Trans Lines

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NOT-PUBLIC DATA HAS BEEN EXCISED

Graph 10

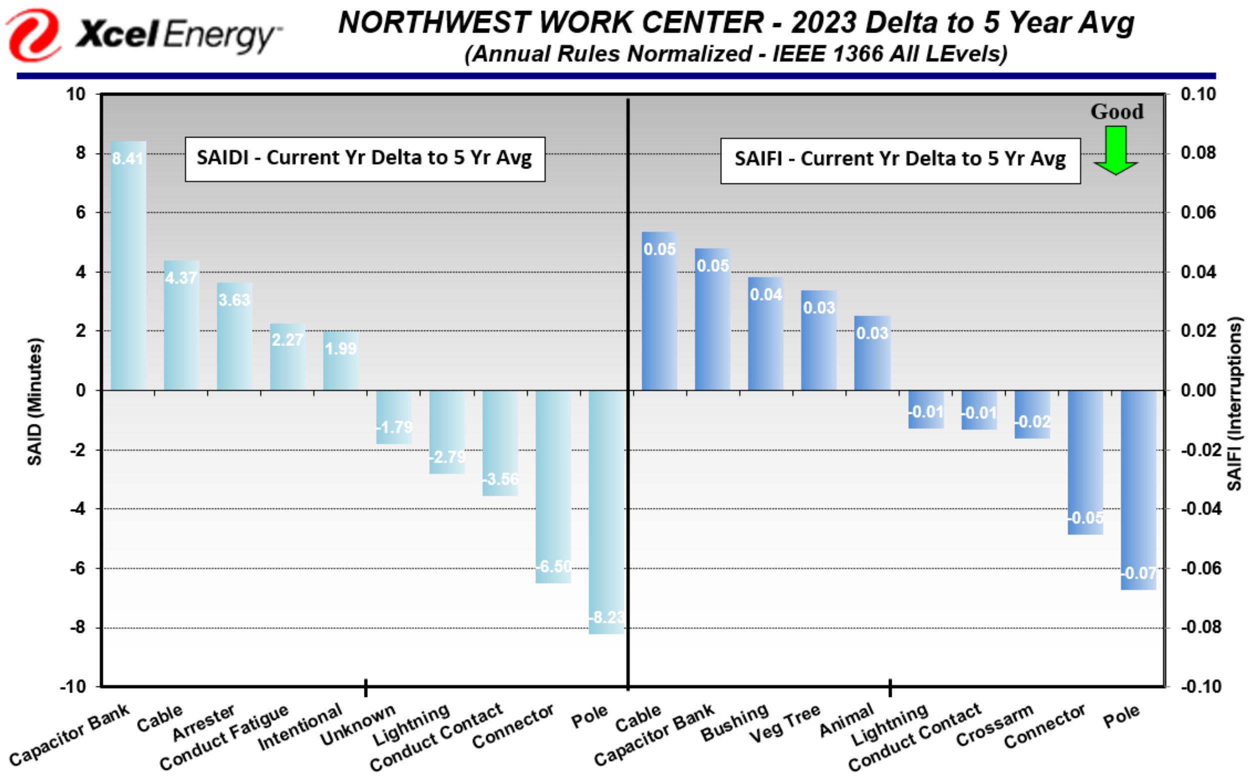


Table 16
Northwest Top Level Outage Causes

Impact events / days

Major Event Days - Excluded from normalized results

Date	SAIDI	SAIFI	CAIDI	Reason
7/25	38.8	0.07	570	High winds/thunderstorms. Many tree, lightning strikes, & equipment failures

Moderate Storm Activity

Date	SAIDI	SAIFI	CAIDI	Reason
4/1	8.8	0.05	174	High winds/snow/ice. Many equipment failures
7/19	7.9	0.06	123	High winds/thunderstorms. Tree contacts & lightning strikes
8/11	4.6	0.03	145	High winds/thunderstorms. Tree contacts, lightning strikes, & equipment failures

Transmission

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
2/7	0.4	0.01	36	Atwater / Lake Lillian	Equipment failure - Broken conductor
4/5	0.4	0.00	178	Greenwald / Grove	Unknown cause event on transmission line - Windy conditions
5/1	1.6	0.01	160	Starbuck / Lowry	Equipment failure - Broken conductor
7/19	2.0	0.02	85	Cold Spring / Wakefield	Tree contact on transmission line - Windy Conditions
9/18	0.4	0.02	25	Monticello	Unknown cause event on transmission line
10/3	2.1	0.03	64	Montrose / Howard	Tree contact on transmission line - Thunderstorm Conditions

Distribution Substation

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
9/20	1.4	0.03	48	St Michael / Monticello	Equipment failure - Substation Bushing
12/20	0.5	0.01	75	Dassel	Other utility caused outage to connecting line

Distribution Lines

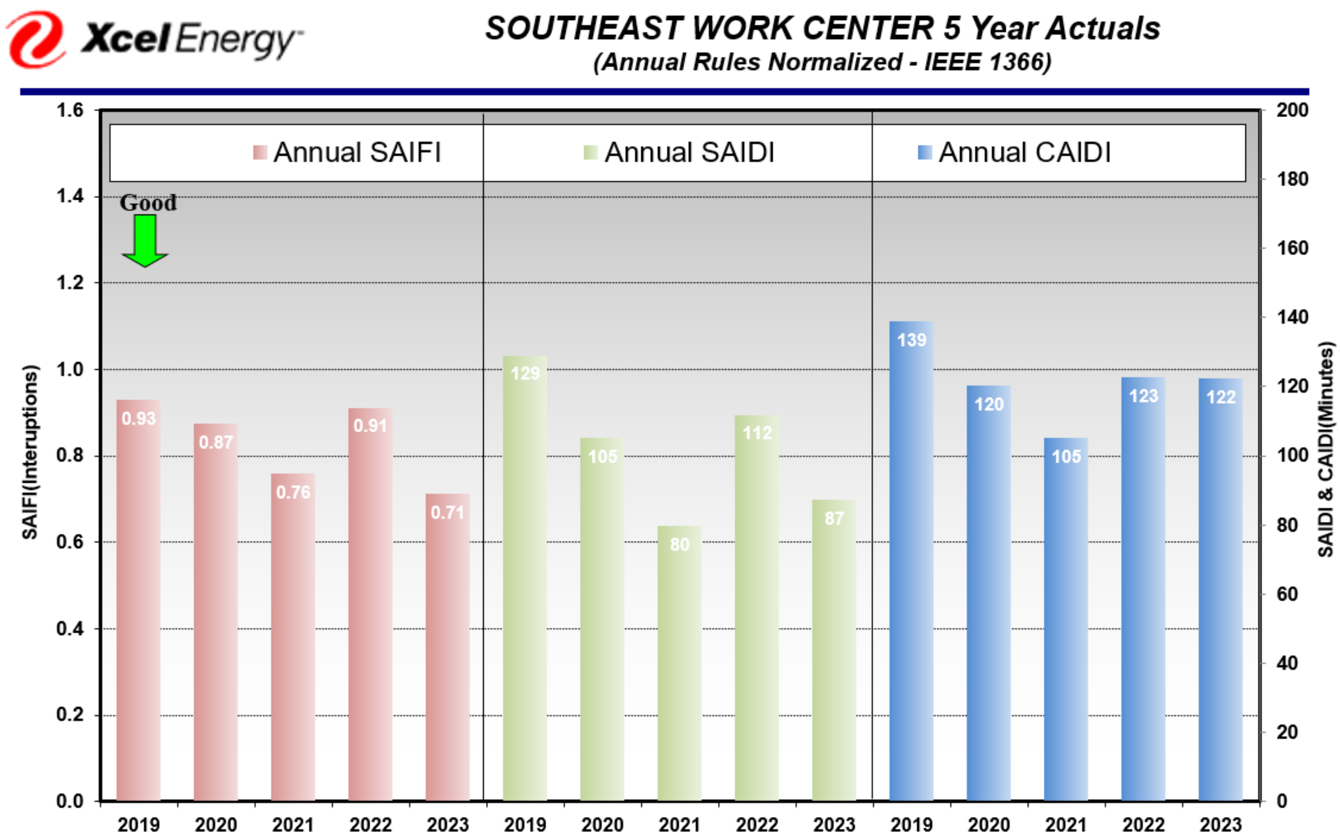
Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
4/1	8.2	0.04	211	St Michael / Monticello	Equipment failure - Capacitor Bank - Icing conditions
6/21	5.1	0.03	166	Hanover/Rogers/St Michael	Equipment failure - Arrester
9/3	3.1	0.03	120	Saint Cloud	Equipment failure - Cable
7/19	3.0	0.02	195	Albertville	Tree contact - Branch on wires
6/29	2.8	0.04	64	Hanover/Rogers/St Michael	Public damage - vehichle hit and damaged pole
8/11	2.7	0.02	122	Sazrtell / Le Sauk	Equipment failure - Pole fire
7/17	1.9	0.03	74	Saint Cloud	Animal contact - mainline
6/23	1.9	0.01	138	Foley / Sauk Rapids	Intentional outage to complete construction repairs
8/11	1.8	0.01	197	Dayton / Rogers	Lightning strike to mainline
7/11	1.7	0.02	112	Montrose / Franklin	Public vehichle hit and damaged pole guy wire

4. *Southeast*

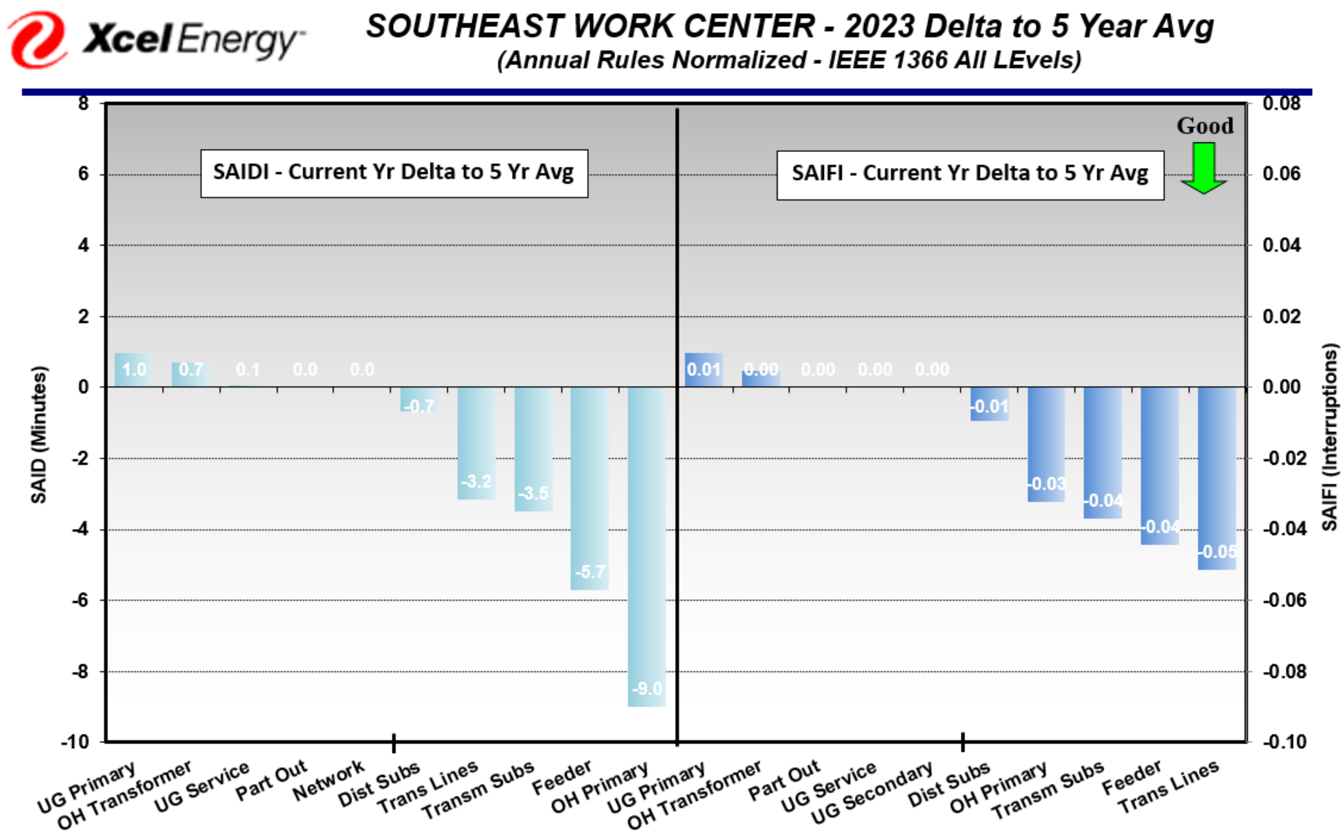
Graphs 11, 12, and 13 show the five-year trend of all three indices, and Table 17 illustrates the top level and cause of outages from the current year that deviated higher and lower than the previous five-year average.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

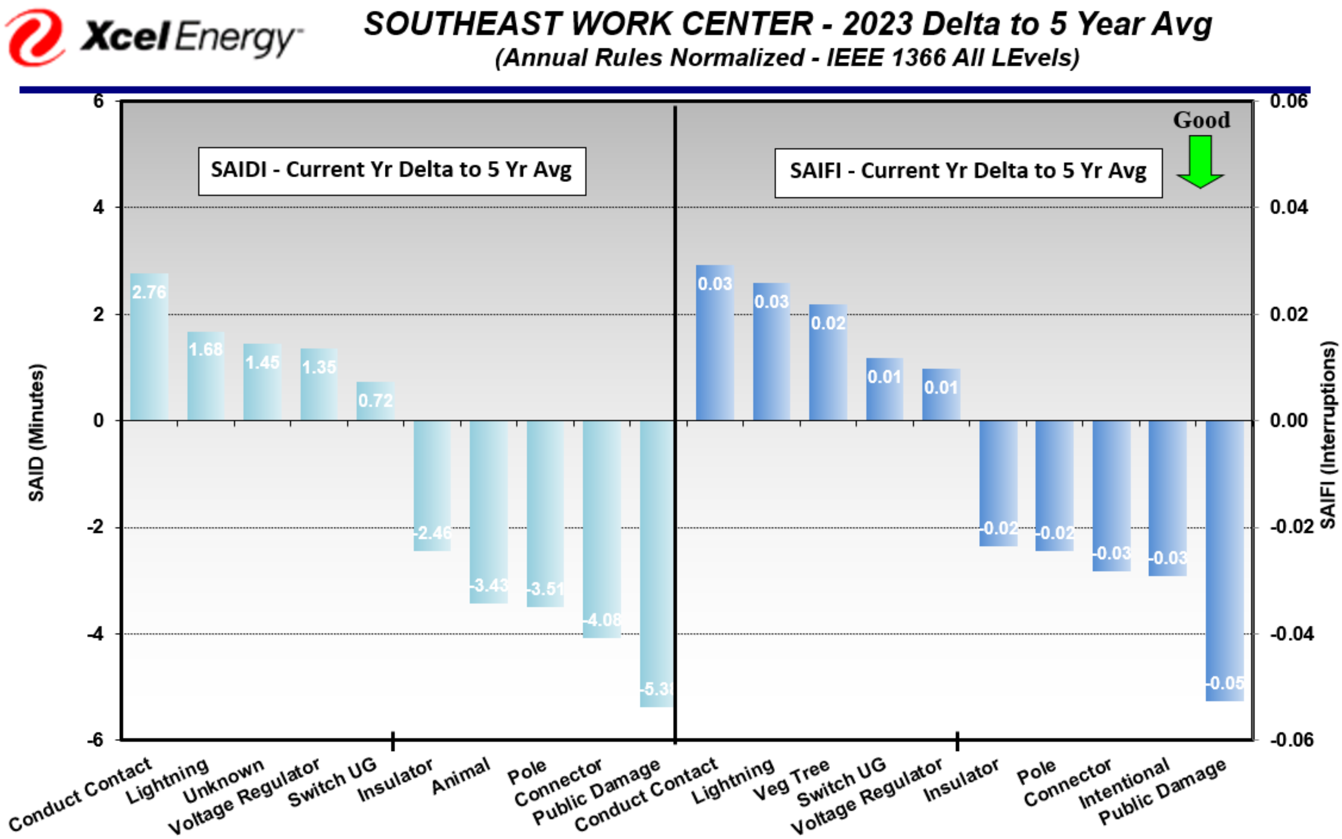
Graph 11



Graph 12


Xcel Energy
SOUTHEAST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
8
6
4
2
0
-2
-4
-6
-8
-10
0.08
0.06
0.04
0.02
0.00
-0.02
-0.04
-0.06
-0.08
-0.10
1.0
0.7
0.1
0.0
0.0
-0.7
-3.2
-3.5
-5.7
-9.0
0.01
0.00
0.00
0.00
0.00
-0.01
-0.03
-0.04
-0.04
-0.05
UG Primary
OH Transformer
UG Service
Part Out
Network
Dist Subs
Trans Lines
Transm Subs
Feeder
OH Primary
UG Primary
OH Transformer
Part Out
UG Service
UG Secondary
Dist Subs
OH Primary
Transm Subs
Feeder
Trans Lines

Graph 13


SOUTHEAST WORK CENTER - 2023 Delta to 5 Year Avg
(Annual Rules Normalized - IEEE 1366 All LEvels)
SAIDI - Current Yr Delta to 5 Yr Avg
SAIFI - Current Yr Delta to 5 Yr Avg
Good
SAID (Minutes)
SAIFI (Interruptions)
6
4
2
0
-2
-4
-6
0.06
0.04
0.02
0.00
-0.02
-0.04
-0.06
2.76
1.68
1.45
1.35
0.72
-2.46
-3.43
-3.51
-4.08
-5.3
0.03
0.03
0.02
0.01
0.01
-0.02
-0.02
-0.03
-0.03
-0.05
Conduct Contact
Lightning
Unknown
Voltage Regulator
Switch UG
Insulator
Animal
Pole
Connector
Public Damage
Conduct Contact
Lightning
Veg Tree
Switch UG
Voltage Regulator
Insulator
Pole
Connector
Intentional
Public Damage

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Table 17
Southeast Top Level Outage Causes

Impact events / days

Major Event Days(MED) - Excluded from normalized results

Date	SAIDI	SAIFI	CAIDI	Reason
7/28	13.6	0.06	216	High winds/thunderstorms. Tree, lightning, and debris strikes to equipment.

Moderate Storm Activity

Date	SAIDI	SAIFI	CAIDI	Reason
1/2-3	4.8	0.05	103	High winds/snow/ice. Tree contacts & equipment failures(Transmission event)
4/1	9.3	0.03	287	High winds/snow/ice. Tree & equipment contacts
6/24	3.5	0.02	158	High winds/thunderstorms. Tree contacts & lightning strikes
7/26-27, 29	6.0	0.06	99	High winds/thunderstorms. Tree contacts & lightning strikes(days before/after MED)
8/11	2.4	0.01	299	High winds/thunderstorms. Tree contacts & lightning strikes

Transmission

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
1/4	0.8	0.01	76	Mapleton/MN Lake	Unknown cause event on transmission line - Icing conditions
3/16	0.4	0.00	98	Rapidan/Good Thunder	Unknown cause event on transmission line - Sleet conditions
3/31	1.1	0.00	236	Gibbon	Unknown cause event on transmission line - Blizzard conditions
4/4	0.4	0.01	68	Edgerton	Conductor Contact - Line contact during icing/windy conditions
4/19	0.8	0.02	37	Northfield	Animal contact in transmission sub
6/28	0.4	0.01	79	Florence / Frontenac	Tree contact on transmission line
6/29	0.1	0.01	19	Nerstrand / Northfield	Lightning strike on transmission line
7/27	0.6	0.01	55	Florence / Frontenac	Tree contact on transmission line
11/15	0.1	0.00	200	Castle Rock / Waterford	Planned Transmission event

Distribution Substation

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
2/10	2.6	0.03	94	Mankato	Overhead switch failure
9/10	1.8	0.02	79	Northfield	Animal contact in the distribution substation

Distribution Lines

Date	SAIDI	SAIFI	CAIDI	Area/s	Reason
4/1	3.1	0.02	191	Zumbrota / Wanamingo	Conductor Contact - Mainline - Snowy conditions
4/1	2.2	0.00	462	Hampton / Vermillion	Tree contact - Icing conditions
4/10	1.7	0.02	101	Cannon Falls/ Hampton	Equipment failure - Mainline cable
1/4	1.7	0.02	106	Redwing	Tree contact - Snowy conditions
3/10	1.5	0.01	207	Tracy / Currie	Equipment failure - Fused cutout
8/11	1.4	0.00	396	Claremont	Tree contact - Thunderstorm conditions
7/26	1.3	0.01	146	Morristown	Equipment lightning strike
6/24	1.3	0.01	162	Jordan	Tree contact - Thunderstorm conditions
5/5	1.2	0.01	153	New Richland / Hartland	Equipment failure - Conductor - Thunderstorm conditions
7/29	1.2	0.02	77	Red Wing / Hay Creek	Tree contact - Thunderstorm conditions

b. Worst Performing Feeders by Work Center

Minn. R. 7826.0500, Subpart 1.H, requires the Company to provide

> *to the extent technically feasible, circuit interruption data, including identifying the worst performing circuit in each work center, stating the criteria that utility used to identify the worst performing circuit, stating the circuits' SAIDI, SAIFI, and CAIDI, explaining the reasons that the circuit's performance is in last place, and describing any operational changes the utility has made, is considering, or intends to make to improve its performance.*

The Commission's April 7, 2006 Order in Docket No. E-002/M-05-551 *reflected an increase by the Commission of the number of feeders that the Company includes in this portion of the report to 25 per work center, for a total of 100.*

Responding to both Minn. R. 7826.0500, Subpart 1.H and the April 2006 Order, Attachment M to this report provides the required feeder performance data by work center, in two sections, identifying the city where the substation for each feeder is located.

We evaluate the worst performing feeders annually and prepare plans and projects to remedy the causes of outages. These projects are largely prioritized and funded through the Feeder Performance Improvement Plan (FPIP) described below and further detailed in Attachment J. However, despite these efforts, occasionally a feeder will reappear on the worst performer list. This can be caused by several reasons, including storms, distance from first responders, or quickly growing vegetation. In addition, feeders can be on the list due to poor tap performance which may not have been investigated in previous years.

For this reason, some of the feeders listed in Attachment M are not actual "poor performers," but rather, are included in the list only because the Company is required to identify 25 feeders, per the April 2006 Order, and their performance values were greater than other feeders (but less than poor performer feeders in that particular work center). For top feeders in each region that were identified as poor performers and needing operational change(s) under the internal Feeder Performance Improvement Plan (FPIP), we have completed a reliability review and provide information on the reasons for the poor performance and any planned improvements in the lower section of each work center's report provided in Attachment M.

The Company's Feeder Performance Improvement Plan (FPIP) annually identifies, poor performing circuits, the causes and changes needed. This cycle begins in September of each year with SAIFI and SAIDI values calculated for the most recent 12 months and cause-data analyzed to determine operational changes. During the fall and early winter months, the construction projects are planned and designed. Construction projects involving overhead equipment begin first with a goal of completion before the spring storm season. Underground construction begins as soon as possible after frost dissipation.

The program's schedule was designed to construct solutions prior to the storm season and to achieve maximum benefit throughout the year. Thus, the data used to determine poor-performing circuits spans September to August rather than an actual calendar year.

In terms of criteria used to identify the feeders, Xcel Energy defines poor performing feeders as those with a SAIFI exceeding three times the average feeder SAIFI value, SAIDI exceeding four times the average feeder SAIDI value, or CAIDI value in the highest 10 percent in current and either of the previous two years. The data used to calculate SAIFI, SAIDI, and CAIDI are not normalized for storm events and exclude outages from transmission and substation as well as planned outage and public damage causes.

The feeder numbers and substation names in Attachment M have been marked as protected data, but pursuant to the Commission's discussion of previous Annual Reports, the Company has added a column providing publicly the City in which the substation is located. The protected data is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). Xcel Energy believes the information could be manipulated to reveal the number of customers served by a particular feeder. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our report.

3. BULK POWER INTERRUPTIONS

Minn. R. 7826.0500, Subpart 1.F requires the Company to provide *"to the extent feasible, a report on each interruption of a bulk power supply facility during the calendar year, including the reasons for interruption, duration of interruption, and any remedial steps that have been taken or will be taken to prevent future interruption."*

During 2023, there were no generation outages on Xcel Energy's system that caused an interruption of service to firm electric customers. All curtailments of customers subject to load management rates or Demand-Side Management (DSM) programs were consistent with the terms of the load management tariffs and DSM programs.

We provide the required information regarding transmission outages as Attachment N to this report. As the incidents shown were reactionary due to storms, public damage, or other activities associated with random and unforeseen events, no plans have been developed to address the specific issues encountered. However, the Transmission Line Performance (TLP) work area works very closely with the area account representatives and trouble men, Transmission Construction, System Operations, and other work areas to proactively inspect and maintain our infrastructure. When determined applicable, TLP will apply specific asset renewal or reliability enhancement programs to identified circuits that extend the circuit's service life and enhances its reliability.

The transmission line names in Attachment N have been marked as protected data. This information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). Xcel Energy believes the information could in some circumstances be manipulated to reveal potential vulnerabilities in our system. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our report.

4. Outage Communications

a. Outage Communications to the CAO

Minn. R. 7826.0500, Subpart 1(G) requires the Company to provide *"a copy of each report filed under part 7826.0700."* Minn. R. 7826.0700, subpart 1, requires the Company to

> *"promptly inform the commission's Consumer Affairs Office (CAO) of any major service interruption" occurring on the utility's system and "provide the following information, to the extent known:*
>
> *A. the location and cause of the interruption;*
> *B. the number of customers affected;*
> *C. the expected duration of the interruption; and*
> *D. the utility's best estimate of when service will be restored."*

Subpart 2, further requires that:

> *Within 30 days, a utility shall file a report on any major service interruption in which 10 percent or more of its Minnesota customers were out of service for 24 hours or more. This report must include at least a description of:*
>
> A. *the steps the utility took to restore service, and*
> B. *any operational changes the utility has made, is considering, or intends to make to prevent similar interruptions in the future or to restore service more quickly in the future.*

In addition, Order Point 4 of the Commission's December 18, 2020 Order in Docket No. E-002/M-20-406 granted a variance to Minn. R. 7826.0500, subp.1, item G and *requires the Company to file a summary table that includes the information contained in the reports similar to Attachment G of Xcel's filing.* The information is included in Attachment O.

"Major Service Interruption" is defined under Minn. R. 7826.0200, subp. 7 as an interruption of service at the feeder level or above and affecting 500 or more customers for one or more hour(s). Xcel Energy complies with Minn. R. 7826.0700, subpart 1, as it sends the Consumer Affairs Office (CAO) notification of sustained outages occurring at the feeder level or above; these notifications also include reporting outages that are not necessarily large enough or long enough to meet the definition of a major service interruption under Minn. R. 7826.0200, subp. 7.

We are committed to providing the CAO with timely and accurate information. Our Customer Advocate Group generally sends these notifications via e-mail directly to the CAO with the required information, to the extent known. During 2023, there were 304 outages on Xcel Energy's system that met the definition of major service interruption under Minn. R. 7826.0200, subp. 7. Please see Attachment O for a summary of the 2023 qualifying outages.

Attachment O contains summary information regarding the Company's feeders and other system components, and associated customers served. This information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). Xcel Energy believes the information could be manipulated to reveal the number of customers served by a particular feeder. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our report.

In an effort to provide information as quickly as we can, whenever possible, our Customer Advocate Group sends the CAO the first outage notification received from the Control Center for an outage event. First notifications often do not include full cause and/or follow-up action information since the restoration crew may not have yet completed its work related to the event. However, we believe it is more important to give the CAO notification as soon as possible rather than waiting for complete information before sending the CAO an alert.

During high volume outage times, it is possible the Control Center does not send an email for each and every outage event. Often during these high-volume events, the Company's Customer Advocate Group works with the Control Center to obtain more general status updates in lieu of individual emails. These updates, which are also forwarded to the CAO, typically include information on which communities were affected, total customers out of service, and any available information on expected restoration times. If available, information is also provided regarding crews brought in from other areas to assist restoration during times of escalated operations.

As with any process that involves human intervention and handoffs, errors will occur, and notices may not be sent to the CAO. There are instances when the Control Center may not create a notice, or the Company's Customer Advocates do not forward a notice to the CAO. In 2023, we did not send an email notice to the CAO for 15 of 304 major service interruptions. These were not sent due to human error and are reflected in Attachment O.

With respect to Minn. R. 7826.0700, subpart 2, the Company had no major service interruptions on our system in 2023 in which 10 percent or more of its Minnesota customers were out of service for 24 hours or more.

b. Outage Communications to Customers (Estimated Restoration)

Order Point 4(d) in the Commission's October 20, 2023 Order in Dockets No. E002/M-22-162 requires the Company *to provide estimated restoration time accuracy, using a) within -90 minutes to 0 of estimated restoration time and b) within 0 to +30 minutes of estimated restoration time.*

On a monthly basis, the Company pulls year-to-date data from its Outage Management System (NMS) that itemizes each outage along with associated outage data such as: (i) time of outage; (ii) number of customers impacted, interrupting device; (iii) level of outage; (iv) estimated restoration time (ERT) pre-determined by the Company; and (v) actual restoration time. The information is used to analyze the accuracy of our estimated restoration times when compared to the actual restoration time.

When an outage is first discovered (by customer notice or otherwise), refined estimates are developed as the Company learns more information. When an outage is identified, an initial automated message is sent to the customer within the first 15 minutes of our Control Center being notified of a customer outage. This message either confirms their outage if they reported it or notifies them of an outage we believe is impacting them.

An ERT is not communicated in the initial customer message. A second communication is sent 20 minutes later, following an escalation process to categorize the outage level, feeder, tap or transformer of an identified outage. If an ERT is available, it would be provided at this time. A standard three-hour outage estimate is assumed when we first discover an outage. A second estimate is created when the Company's first responder gets on site in the field and begins their investigation. Finally, a third, more refined estimate, is developed when field personnel are able to assess the cause of the outage and determine the necessary remediation action. Additional messages to the customer during the outage will be dependent on ERT changes or the outage being closed. The final message the customer receives will confirm their power has been restored and provides a way for the customer to report if they are still without power.

The current ERT metric includes those generated by our model (which is based on the impacted device(s) and algorithms) and ERTs entered by field and control center personnel. The model usually provides an estimate within 20 minutes after notification of an outage. The -90 to 0 minute window of accuracy is used by the Company to track our accuracy of reporting to customers. The Commission also requested that we provide information about our accuracy for the 0 to +30 window of accuracy; we have provided "+1 to +30" to ensure we are not double counting any instances where the outage is restored exactly at 0. We have included an additional table that provides accuracy of +1 to +90. Pursuant to Order Point 4(d), we provide Tables 18, 19, and 20 which summarize the annual percent accuracy of ERT estimates provided to electric customers in the NSPM Operating Company, as well as the Minnesota Jurisdiction for the years 2019 thru 2023.

Table 18

		Estimated Restoration Time Accuracy				
Entity	**Accuracy Criteria**	**2019**	**2020**	**2021**	**2022**	**2023**
NSPM	Within -90 to+0	48.3%	53.4%	53.9%	50.4%	48.3%
MN Only	Within -90 to+0	49.9%	54.3%	54.8%	51.6%	49.5%

Table 19

		Estimated Restoration Time Accuracy				
Entity	**Accuracy Criteria**	**2019**	**2020**	**2021**	**2022**	**2023**
NSPM	Within +1 to +30	10.0%	10.4%	11.3%	12.5%	9.5%
MN Only	Within +1 to +30	10.4%	10.3%	10.9%	11.5%	8.2%

Table 20

		Estimated Restoration Time Accuracy				
Entity	**Accuracy Criteria**	**2019**	**2020**	**2021**	**2022**	**2023**
NSPM	Within +1 to +90	18.6%	16.6%	19.3%	23.8%	20.6%
MN Only	Within +1 to +90	18.7%	16.4%	18.5%	19.9%	17.6%

Overall, ERT accuracy has remained relatively flat in NSPM and MN in the -90 to 0minute window from 2019 to 2023. This process includes our manual ERT's, or the estimates field representatives provide after they have been able to assess the cause of the outage and determine the necessary remedial action. Field representatives are trained annually on how to assess the ERT in differing situations to help refine the restoration window.

We continue to provide several proactive communication channels when an outage occurs such as email, text, and push notifications via a mobile app. We also provide notification channels that require the customer to pull the information such as our website, social media and outage maps.

Pull channels (website, social media, and outage map) leverage the same data sources as our push channels. This ensures consistent information across channels and provides additional resources to our customers. Customers can also receive information via two-way text. A customer can text us "OUT" to report an electric outage or "STAT" and receive an on-demand text message as to the status of their outage.

The Company continues to identify systems and tools to be used during outages to help improve the outage customer experience. For instance, in 2022 the Company successfully implemented the Electric Outage Restoration (EOR) App. The EOR provides an alternative for receiving assigned outages, completing more convenient and timely status updates and closing electric outage orders in the field. Benefits include increased mobility, integrated customer information and navigation assistance. Ongoing development of the EOR application in 2023 has further improved the timeliness of status updates made by the field personnel, which allows the customer to be well-informed of any updates to the estimated restoration timing.

5. Voltage Fluctuations

Minn. R. 7826.0500 Subpart 1.I requires the Company to provide *"data on all known instances in which nominal electric service voltages on the utility's side of the meter did not meet the standards of the American National Standards Institute for nominal system voltages greater or less than voltage range B."*

Voltage deviations typically result from customers experiencing problems with electrical equipment. High voltage can shorten the life of lightbulbs or result in electric motor damage. Low voltage can have equally significant consequences.

A first responder initially handles customer voltage complaints. If a non-voltage cause cannot be found, we initiate a voltage investigation, and install a recording voltmeter. In the metro area, Xcel Energy has a dedicated technician that sets these recorders and performs the voltage investigations. In the non-metro areas, a first responder or a district representative conducts the voltage investigations.

Xcel Energy's allowable service voltage range is 120 volts plus/minus five percent, or a minimum of 114 volts to a maximum of 126 volts. As shown in the table below, Xcel Energy's allowable service voltage range is within the American National Standards Institute (ANSI) voltage range B.

Table 21
Allowable Service Voltage Range

	Minimum Voltage	Maximum Voltage
ANSI Voltage Range B (service voltage)	110	127
Xcel Energy Range (service voltage)	114	126

During 2023, the Company conducted 319 voltage investigations. The investigations resulted in a diagnosis of a specific voltage problem where voltage did not meet the standards of ANSI Voltage Range B in 113 of the cases. These problems are typically the result of transformer overloads or some other equipment malfunction, such as capacitor banks or voltage regulators. In 2023, we began seeing more voltage investigations related to an increase in the penetration of solar generation, which can cause additional volt/var variance. In all other cases, either no problem was found, or the root cause was attributed to something other than voltage deviations. In cases where the Company finds the voltage to be out of the acceptable range, we take appropriate actions, including but not limited to swapping transformers, upgrading transformers, or checking capacitor banks.

6. Staffing

Minn. R. 7826.0500 Supb. 1.J requires the Company to provide *"data on staffing levels at each work center, including the number of full-time equivalent positions held by field employees responsible for responding to trouble and for the operation and maintenance of distribution lines."*

In addition, Order Point 4(j) in the Commission's October 20, 2023 Order in Docket No. E002/M-22-162, requires the Company to provide *"separate information on the number of contractors for each work center."*

In response to both subpart 1.J and Order Point 4(j), Table 22 below reflects staffing levels by work center. This table also includes counts for work center personnel that support the electric distribution function such as Administrative Assistant, Ops Coordinators, Designers, Field Operations Associates, Operations Managers, Operations Specialists, Electric Meter Specialists, Distribution Design Supervisor, Field Ops Supervisor, Meter Technician, etc. The total headcount reflects Company employees with a limited number of staff augmentation employees that fill the job of electric service designers. In 2023, Trouble and O&M staffing increased in one work center by a headcount of five employees; however, two work centers decreased due to attrition of retirements and employee relocations. Work center support staff decreased by one to seven employees.

Table 22
2023 Staffing Levels by Work Center

	Metro East	Metro West	Northwest	Southeast	Other *
Trouble and O&M Staffing	135	193	29	50	56
Work Center Support (and Contractors)	49 (4)	68 (8)	16 (0)	40 (0)	24 (1)

* Xcel Energy personnel associated with the South Dakota / North Dakota work centers provide support in western Minnesota and the Dakotas.

Current open and posted Trouble and O&M positions include three in the Northwest work center; two positions in the Southeast work center, one in the Metro East work center and one in Other. Current open and posted work center support positions include three in the Metro East work center and two in the Southeast work center.

We note that although we are reporting staffing levels by work center, our field personnel continue to respond to trouble and perform duties in other work centers as need arises.

The contractor counts included in Table 22 above are for a limited number of positions that fulfill the role of Service Designers in our work centers. The Company also hires contractors to perform field and maintenance work, but the Company's contracts with its bargaining employees contain certain agreements regarding when and how contractors can be used. As a general principle, the number of contractors in a region cannot exceed the number of internal field and maintenance personnel. The Company hires contractors to assist with large requests for new service or maintenance projects such as large pole replacement projects discovered through our pole testing program or major distribution line rebuilds. Contractors can also perform outage response if the Company experiences staffing constraints or if there is emergent outage work (for example, an anticipated large storm system) and the Company determines it is reasonable to redeploy contract crews to the area to respond to expected outages.

Because of the nature of this work, contractors are not assigned to a particular work center. Rather, they work in various work centers depending on the service needs of our customers in Minnesota. Historically, the Company uses the most contractors during the summer months (when most contractor time is used to assist with large requests for new service) and fewer contractors during the winter months. However, the Company does utilize contractors in the winter for programmatic maintenance work, such as the pole replacements or distribution rebuilds described above.

C. OTHER RELIABILITY METRICS REQUESTED BY THE COMMISSION

1. MAIFI

In the Commission's October 20, 2023 Order in Docket No E002/M-22-162, Order Point 4(c), the Commission required the Company to provide *normalized and non normalized reporting of MAIFI data.*

Momentary outage information is available at the Feeder-level and above, by Feeder circuit, and only on Feeders that are located in substations with Supervisory Control and Data Acquisition (SCADA) capability. With current distribution infrastructure, there is SCADA capability at 68 percent of our substations and approximately 90 percent of customers are served from these substations. Since MAIFI reporting at the substation level required this capability, our reporting for MAIFI would also cover approximately 90 percent of our customers.

Table 23 contains our 2023 MAIFI results. Descriptions of the MAIFI calculation methodologies we applied can be found following Table 24.

Table 23
2023 MAIFI Results

	Non-Normalized	Xcel Energy QSP Tariff	Xcel Energy Annual Rules
Region	**2023**	**2023**	**2023**
Minnesota	0.69	0.53	0.63
Metro East	0.60	0.45	0.49
Metro West	0.62	0.55	0.57
Northwest	1.27	0.86	1.25
Southeast	0.79	0.36	0.78

Table 24 provides our MAIFI performance from 2014 to 2023 for the Tariff and Rules method on a normalized basis using the 2.5 beta method outlined in IEEE 1366. In addition, Table 24 includes non-normalized values per the Commission's Decision in Docket No. E002/M-18-239.

Table 24
MAIFI 2014 – 2023 Normalized

All Days - All Levels, All Causes

MAIFI(<=5Mins)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Metro East	0.70	0.89	0.80	0.82	0.84	0.74	0.97	0.77	0.82	0.60
Metro West	0.82	0.73	0.85	0.61	0.56	0.64	0.72	0.53	0.70	0.62
Northwest	1.51	1.44	1.42	1.37	1.42	1.52	1.27	1.41	0.85	1.27
Southeast	1.20	0.88	1.05	0.73	0.92	1.22	0.96	0.83	0.78	0.79
Minnesota	0.89	0.86	0.91	0.76	0.77	0.82	0.88	0.72	0.76	0.69

Tariff - IEEE No Transmission Line, All Causes

MAIFI(<=5Mins)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Metro East	0.55	0.81	0.70	0.65	0.81	0.54	0.85	0.69	0.61	0.45
Metro West	0.67	0.55	0.65	0.51	0.53	0.61	0.62	0.50	0.56	0.55
Northwest	0.81	0.69	0.64	0.85	0.75	0.84	0.75	0.95	0.62	0.86
Southeast	0.34	0.32	0.39	0.37	0.44	0.48	0.56	0.52	0.42	0.36
Minnesota	0.61	0.62	0.64	0.57	0.63	0.60	0.70	0.60	0.57	0.53

Annual Rules - IEEE All Levels, All Causes

MAIFI(<=5Mins)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Metro East	0.57	0.82	0.76	0.79	0.83	0.70	0.95	0.73	0.67	0.49
Metro West	0.80	0.64	0.76	0.55	0.55	0.64	0.63	0.51	0.60	0.57
Northwest	1.51	1.44	0.95	1.28	1.42	1.43	1.22	1.37	0.76	1.25
Southeast	0.97	0.88	1.00	0.73	0.78	0.99	0.90	0.79	0.74	0.78
Minnesota	0.81	0.80	0.80	0.71	0.75	0.77	0.82	0.69	0.65	0.63

Below is a description of how each of the three MAIFI performance methods is calculated:

<u>Non-normalized</u>

- Includes outages occurring at all levels (distribution, substation, and transmission).
- Includes all outage cause codes.
- Calculations are based on the number of customers' billing accounts and meters.
- Include all days in calculations.

<u>Xcel Energy (Quality of Service Plan Tariff Method)</u>

- Excludes outages occurring at Transmission Line level.
- Includes all outage cause codes.
- Calculations are based on the number of customers' billing accounts and meters.
- Excludes all Major Event Days that qualify under IEEE 2.5 normalization method after removing Transmission Line level.

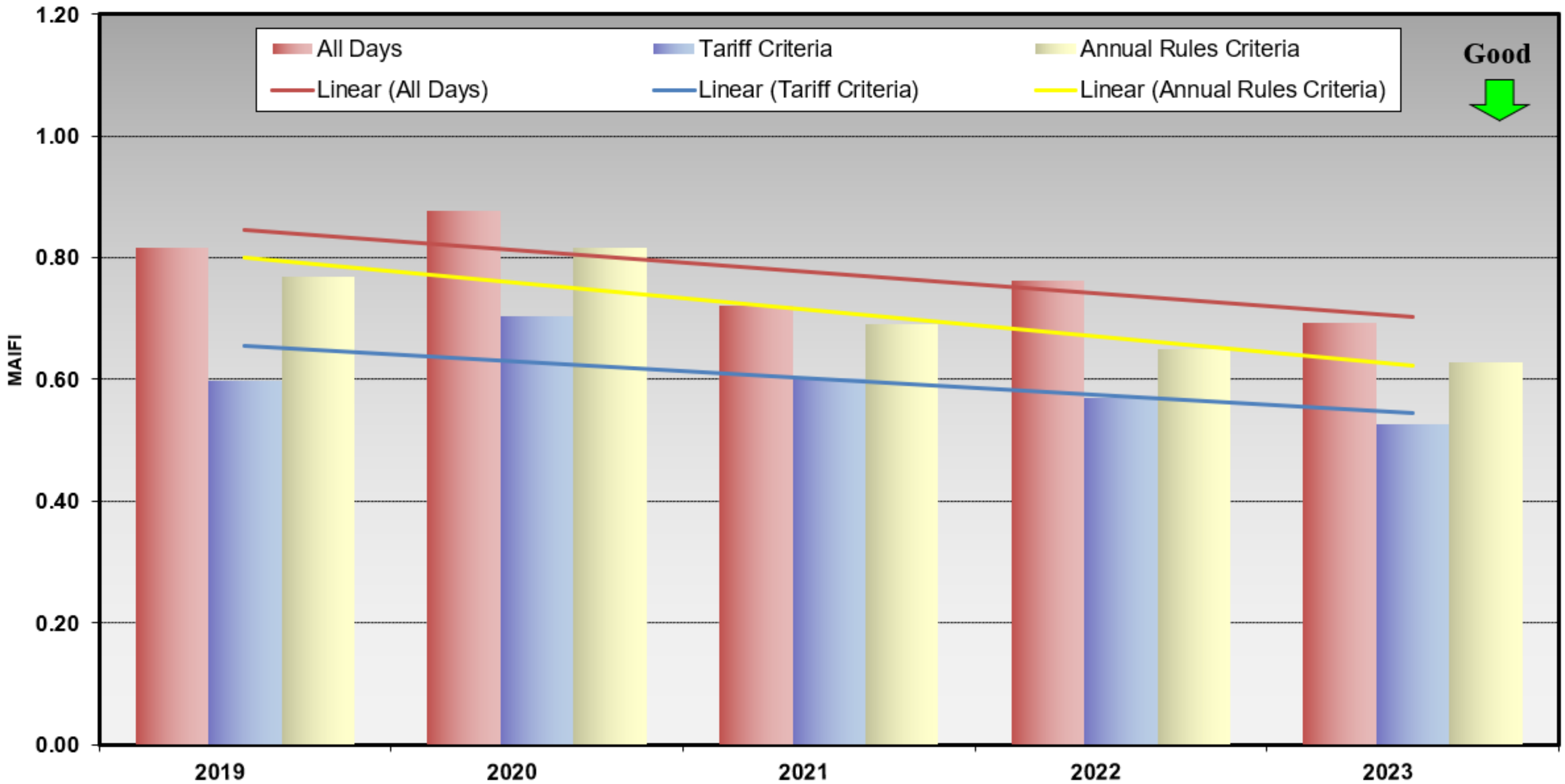
Xcel Energy (Annual Rules Method)

- Includes outages occurring at all levels (distribution, substation, and transmission).
- Includes all outage cause codes.
- Calculations are based on the number of customers' billing accounts and meters.
- Excludes all Major Event Days that qualify under IEEE 2.5 normalization method using all levels.

Graph 14 provides a five-year historical look for Minnesota MAIFI showing the three different normalization methodologies and the associated trend lines.

Graph 14

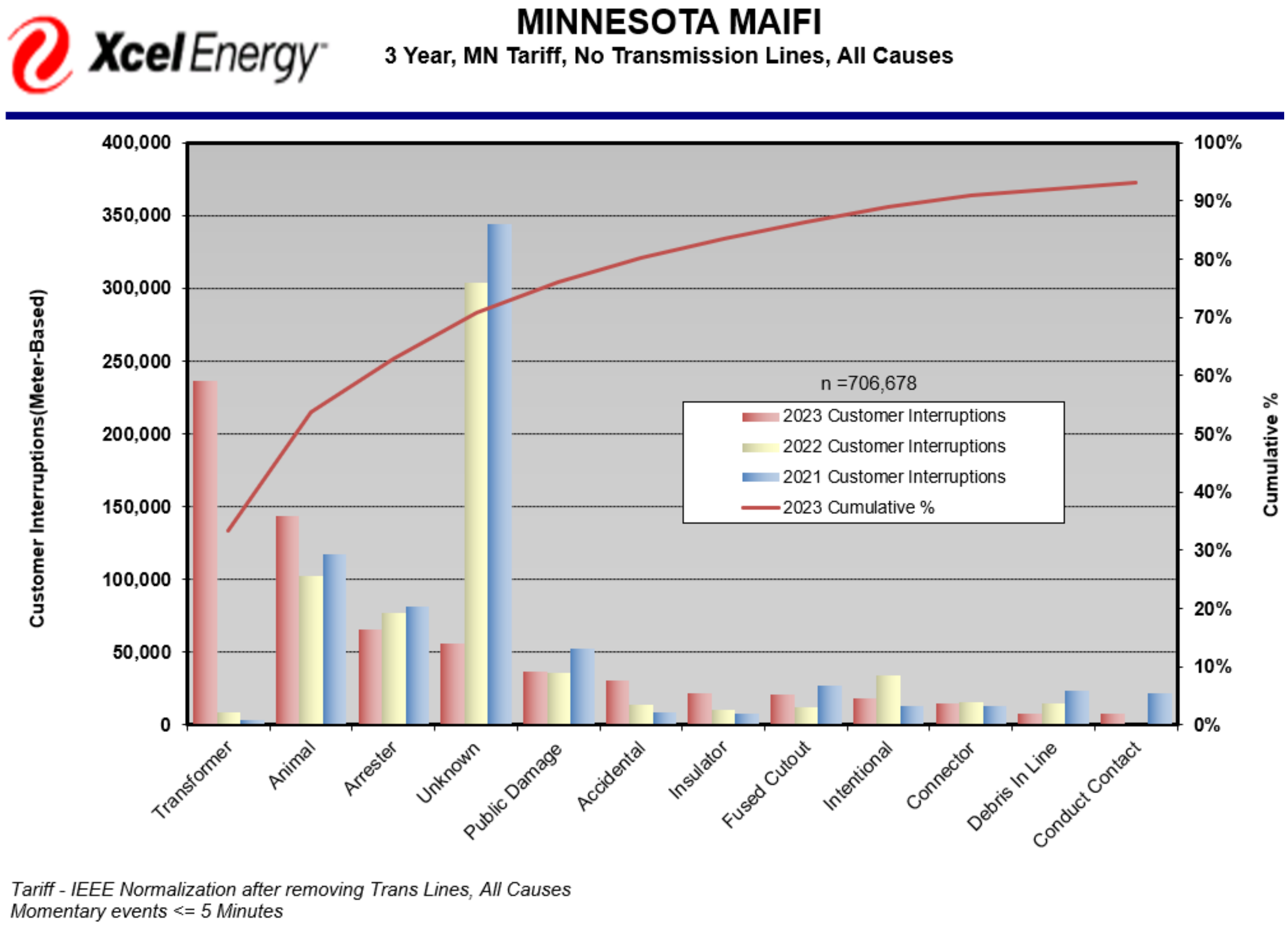
MINNESOTA MAIFI



All Days - No normalization, All Levels, All Causes
Annual Rules - IEEE 1366 Region Normalization, All Levels, All Causes
Tariff - IEEE 1366 Region Normalization after removing Trans Lines, All Causes
Momentary events <= 5 Minutes

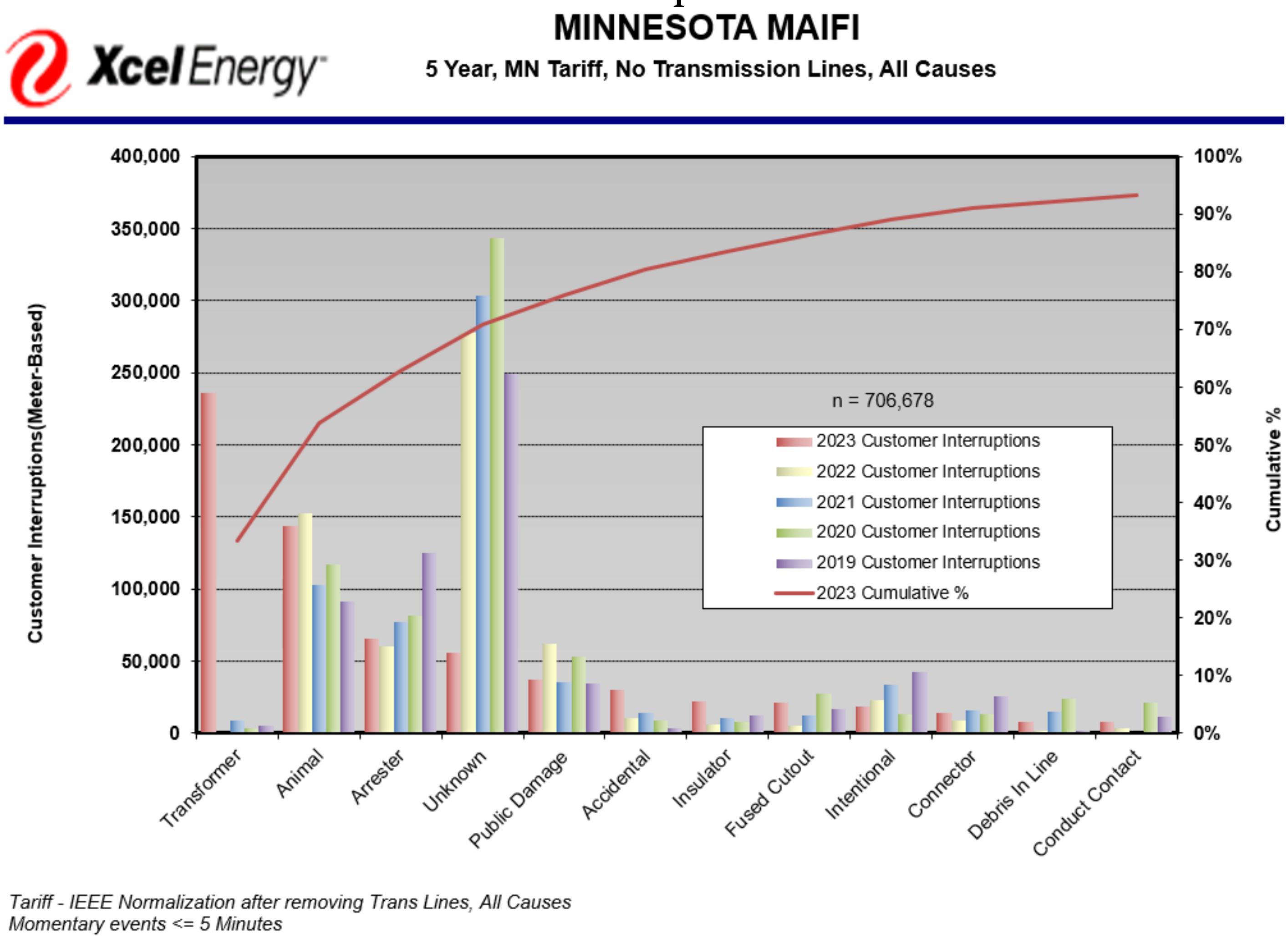
Graph 15 provides a pareto chart showing the top causes for 2023 interruptions.

Graph 15



Graph 16 below is the pareto chart showing the top causes for interruptions for the past five years.

Graph 16



Attachment P provides the detailed MAIFI results and Customer Interruptions by month and by work center for 2019 to 2023.

Our system capabilities and procedures have changed and evolved over time. Therefore, the historical MAIFI results will be based on what our protocol and physical capabilities were for capturing momentary events at that point in time.

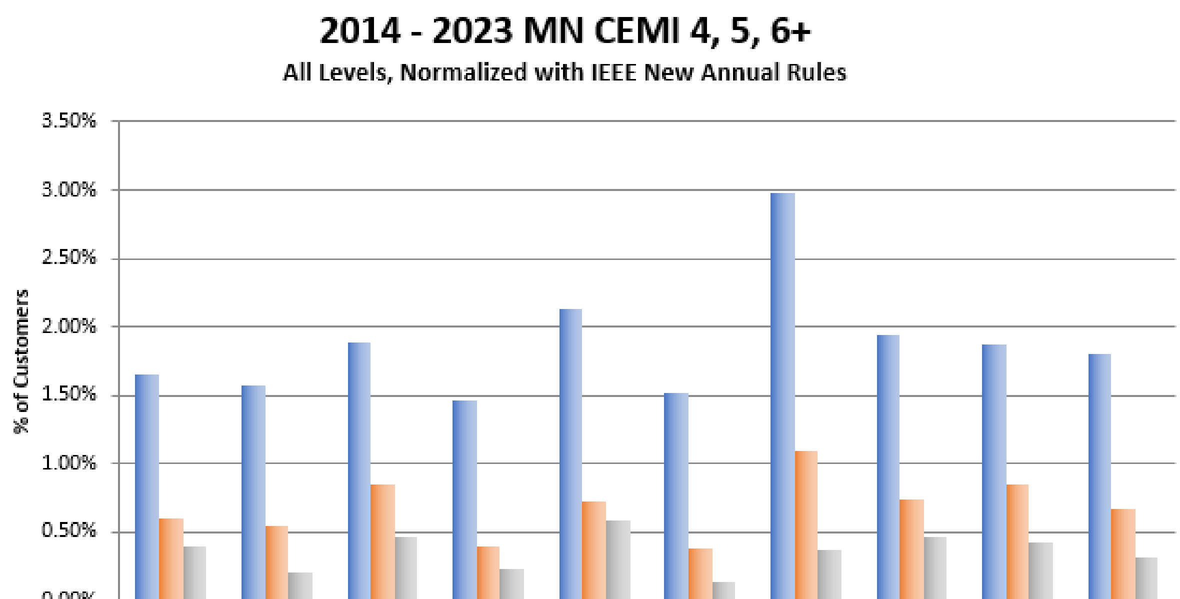
2. Customers Experiencing Multiple Interruptions (CEMI)

The Commission's October 20, 2023 Order in Docket No E002/M-22-162 at Order Point 4(e) required the Company *to provide CEMI at normalized and non-normalized outage levels of 4, 5, and 6*.

Below, Graph 17 illustrates CEMI results for 2014-2023, normalized using the IEEE 1366 Annual Rules methodology. The bar graph breaks out Minnesota customers that experienced four, five, or six plus events. As shown, the customers experiencing six or more events are typically a much smaller percentage than those experiencing only four or more events. Internally, the Company tracks those experiencing four or more outages on a 12-month rolling basis and reviews opportunities to improve performance through mitigation efforts such as additional tree trimming or installation of animal protection. Just as SAIDI varies from year-to-year, CEMI will vary from year-to-year typically due to weather patterns.

It should be noted that under our Service Quality Tariff, CEMI-related outage credits are given to customers experiencing six or more outage events in a year based on the tariff normalization methodology.

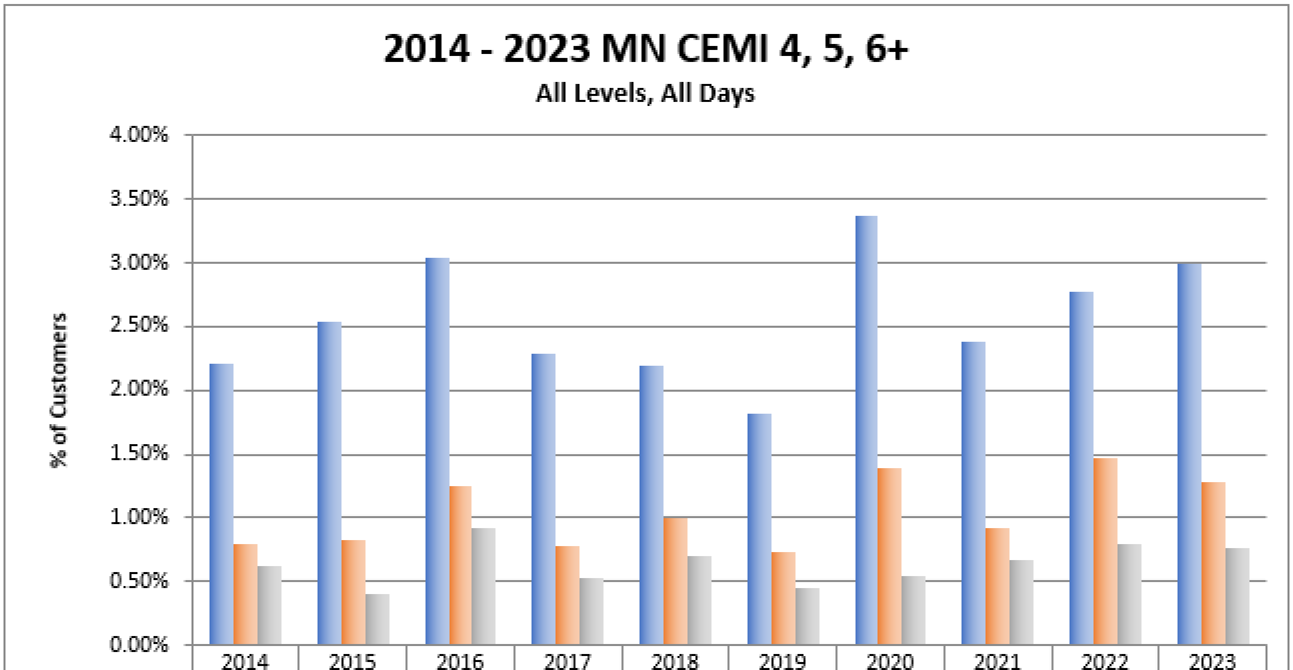
Graph 17



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
CEMI4	1.65%	1.57%	1.88%	1.46%	2.13%	1.52%	2.98%	1.94%	1.87%	1.80%
CEMI5	0.59%	0.55%	0.85%	0.39%	0.72%	0.38%	1.09%	0.73%	0.85%	0.67%
CEMI6+	0.40%	0.20%	0.47%	0.23%	0.59%	0.14%	0.37%	0.47%	0.42%	0.31%

Graph 18 illustrates CEMI, non-normalized (with MEDs) 2014–2023 data.

Graph 18



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
CEMI4	2.21%	2.53%	3.04%	2.28%	2.20%	1.82%	3.36%	2.38%	2.77%	2.99%
CEMI5	0.79%	0.82%	1.25%	0.77%	1.00%	0.73%	1.40%	0.91%	1.47%	1.28%
CEMI6+	0.63%	0.41%	0.91%	0.52%	0.70%	0.45%	0.54%	0.67%	0.79%	0.76%

The Commission's October 20, 2023 Order, in Docket N. E002/M-22-162 Order Point 4(f) further required the Company *to provide the highest number of interruptions experienced by any one customer (or feeder, if customer level is not available.)*

In 2023, one customer had the highest number of normalized outages (11 outages), and five customers had the highest number for all days (14 outages). The one customer with the highest normalized count resides in the Metro West region while the five customers with the highest all days count reside in the Metro East region.

The majority of the normalized outages (six) were from tree limbs contacting the lines. In addition, three were from cables cut and bad locates, one from animal contact, and one from equipment failure (cable failure).

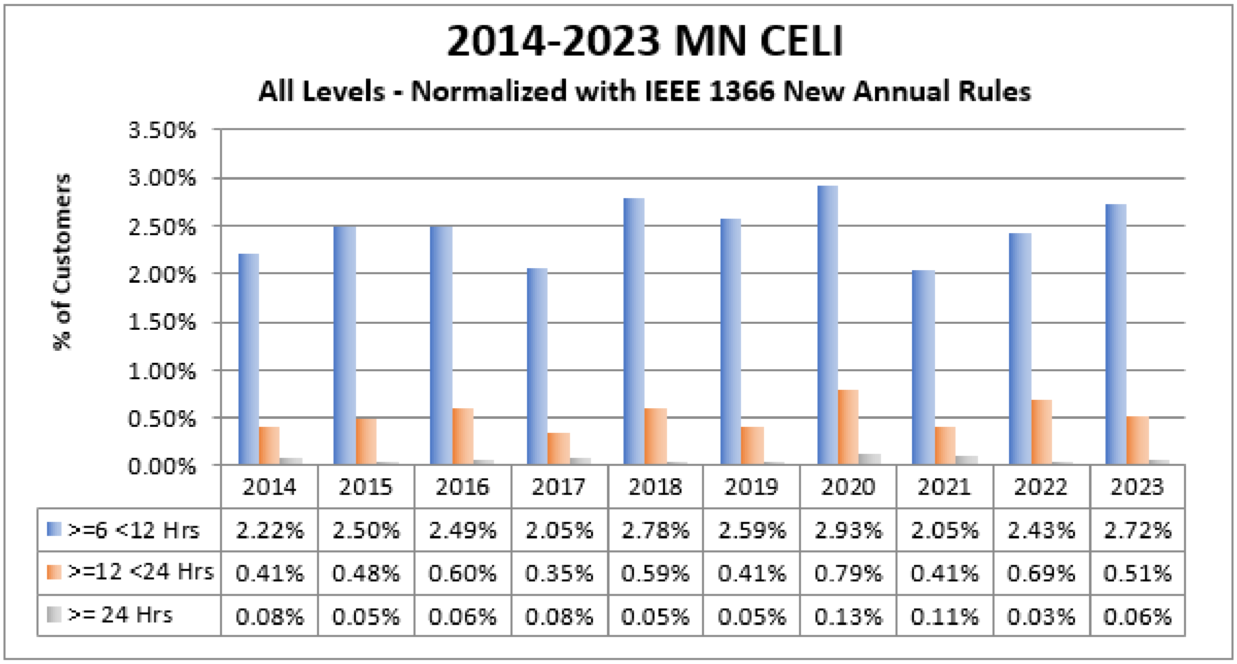
The majority of the all-days outages were weather-related outages (twelve tree limb contact outages). In addition, there were two unknown cause outages. Six of the weather-related outages were due to major storms and were considered major event days.

3. Customer Experiencing Lengthy Interruptions (CELI)

The Commission's October 20, 2023 Order in Docket No E002/M-22-162 at Order Point 4(g) required the Company *to provide CELI at normalized and non-normalized intervals of greater than 6 hours, 12 hours, and 24 hours.*

Graphs 19 and 20 (normalized and non-normalized, respectively) illustrate the Company's CELI for the percentage of Minnesota customers that experienced long outages. The outages are categorized by those 6 hours or more but less than 12 hours, 12 hours or more but less than 24 hours and 24 hours or more during a calendar year. If a customer experienced an outage, this represents the percent chance, by year, of the outage lasting more than 6, 12, or 24 hours. Ten years of data are represented (2014-2023) and are normalized based on the IEEE 1366 methodology. Graph 19 provides a slightly different view than the CELI based outage credits in our Service Quality Tariff. The Tariff credits are provided to customers that experience an outage greater than 24 hours based on the tariff methodology. As with the other metrics, although the normalization method attempts to remove the year-to-year variability, variability still occurs, typically due to weather patterns.

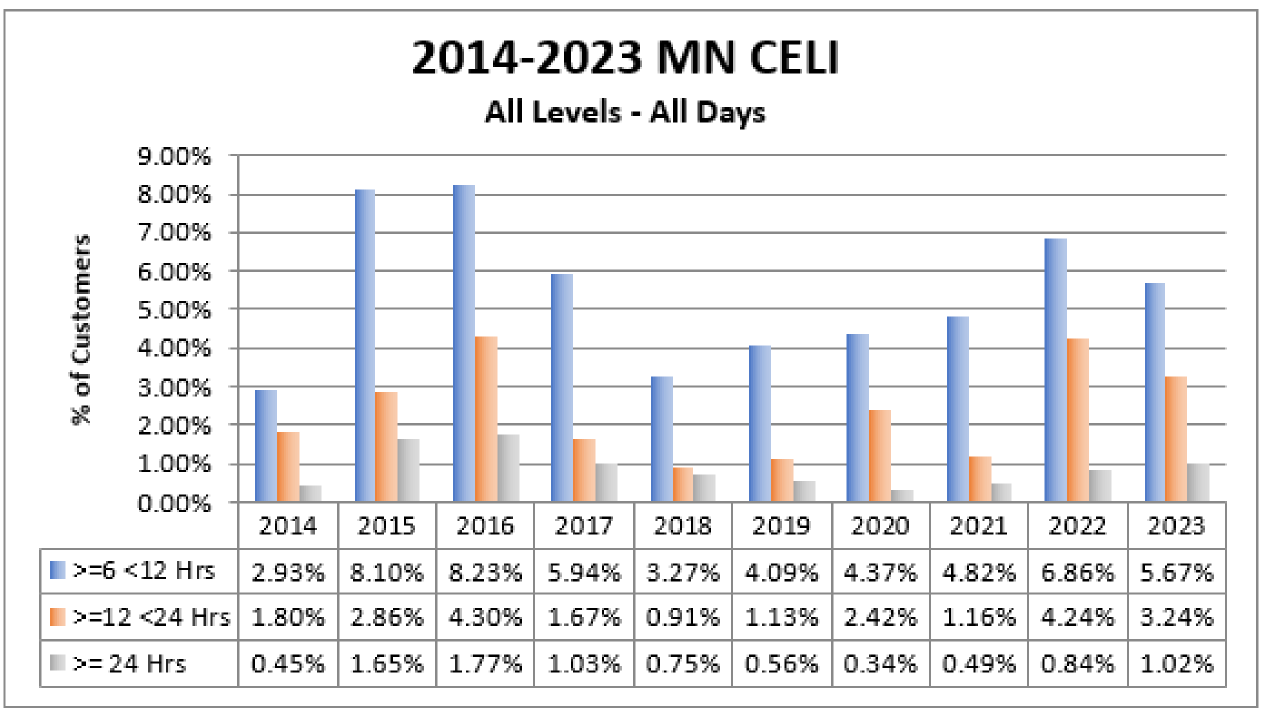
Graph 19



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
>=6 <12 Hrs	2.22%	2.50%	2.49%	2.05%	2.78%	2.59%	2.93%	2.05%	2.43%	2.72%
>=12 <24 Hrs	0.41%	0.48%	0.60%	0.35%	0.59%	0.41%	0.79%	0.41%	0.69%	0.51%
>= 24 Hrs	0.08%	0.05%	0.06%	0.08%	0.05%	0.05%	0.13%	0.11%	0.03%	0.06%

Graph 20 illustrates CELI, non-normalized (with storms) 2014–2023 data.

Graph 20



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
>=6 <12 Hrs	2.93%	8.10%	8.23%	5.94%	3.27%	4.09%	4.37%	4.82%	6.86%	5.67%
>=12 <24 Hrs	1.80%	2.86%	4.30%	1.67%	0.91%	1.13%	2.42%	1.16%	4.24%	3.24%
>= 24 Hrs	0.45%	1.65%	1.77%	1.03%	0.75%	0.56%	0.34%	0.49%	0.84%	1.02%

The Commission's October 20, 2023 Order in Docket No E002/M-22-162, Order

Point 4(h) further required the Company *to provide the longest experienced interruption by any one customer (or feeder, if customer level is not available.)*

The longest duration for normalized outages was due to a planned outage on May 3, 2023 to disconnect two services for tree cutting. This outage with a duration of 7,213 minutes affected two customers in the Metro West region.

We note that the IEEE Distribution Reliability Working Group does not benchmark CEMI or CELI and the Edison Electric Institute (EEI) benchmark information for CEMI is proprietary. As a result, we are unable to share it. However, the CEMI information stated here is similar in metric design to what EEI uses (which is the count of customers who experience "x" number of outages or more in a year using normalized data) based on several counts of outages.

V. PROPOSED ELECTRIC RELIABILITY STANDARDS FOR 2024

Minn. R. 7826.0600, subp. 1 *requires each utility to propose standards for the following reliability indices:*

- *System Average Interruption Duration Index (SAIDI),*
- *System Average Interruption Frequency Index (SAIFI, and*
- *Customer Average Interruption Duration Index (CAIDI).*

SAIDI measures the average total number of minutes a customer was without power during a calendar year. This index is calculated as follows:

$$\textbf{SAIDI} = \frac{\textbf{Total Customer Minutes of Sustained Outages}}{\textbf{Number of Customers}}$$

SAIFI measures the average frequency of sustained service interruptions per customer during a calendar year and is calculated as follows:

$$\textbf{SAIFI} = \frac{\textbf{Total Number of Sustained Customer Interruptions}}{\textbf{Number of Customers}}$$

CAIDI measures the average outage time a customer could expect to be without power if they experienced a sustained outage and is calculated as follows:

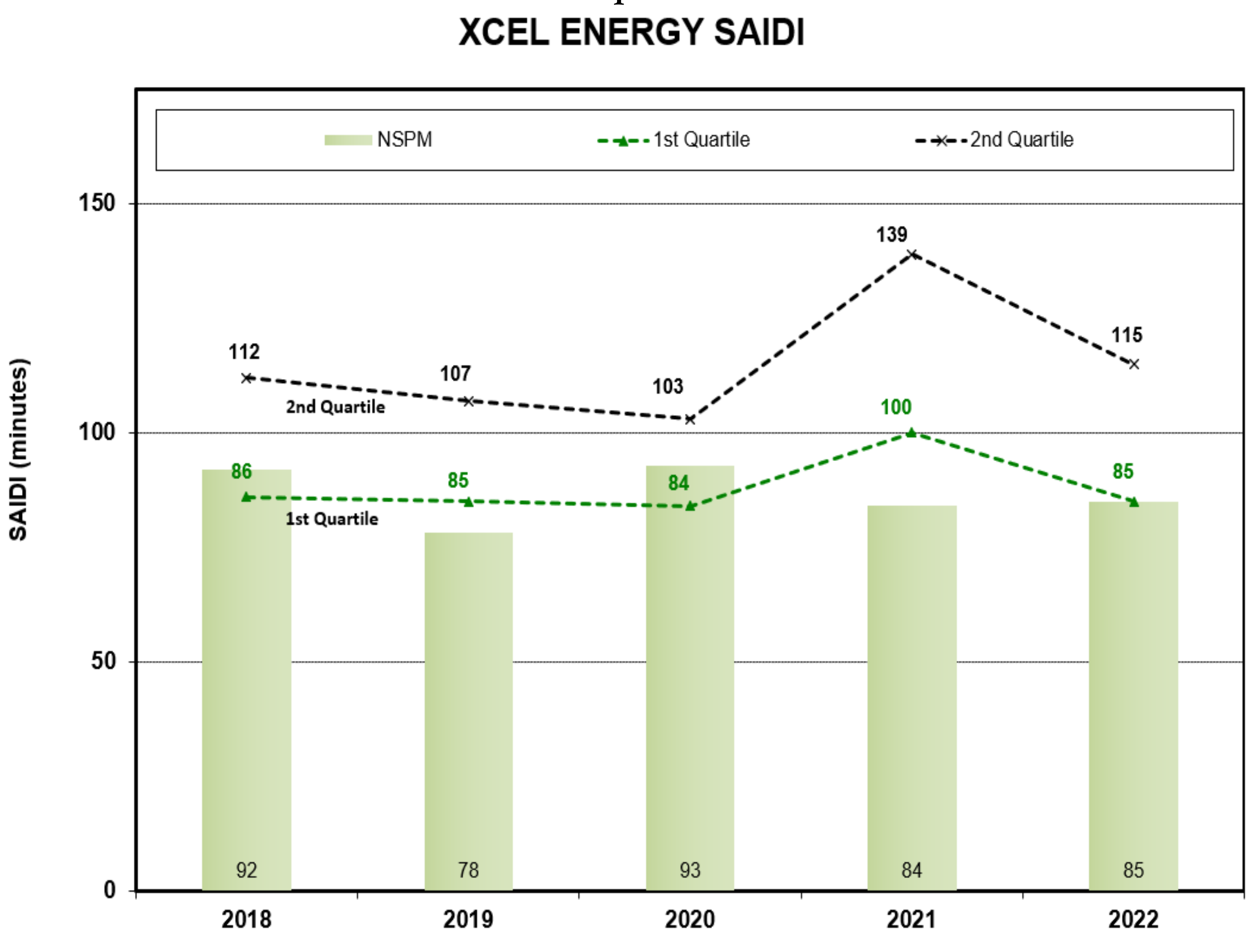
$$\textbf{CAIDI} = \frac{\textbf{Total Customer Minutes of Sustained Outages}}{\textbf{Total Number of Sustained Customer Interruptions}}$$

Minn. R. Chapter 7826 allows utilities to report reliability performance using normalized data. Normalized data is defined by Minn. R. 7826.0200, subp. 9 as "data that has been adjusted to neutralize the effects of outages due to major storms."

A. Benchmarking the Company's SAIDI, SAIFI, and CAIDI Performance with IEEE

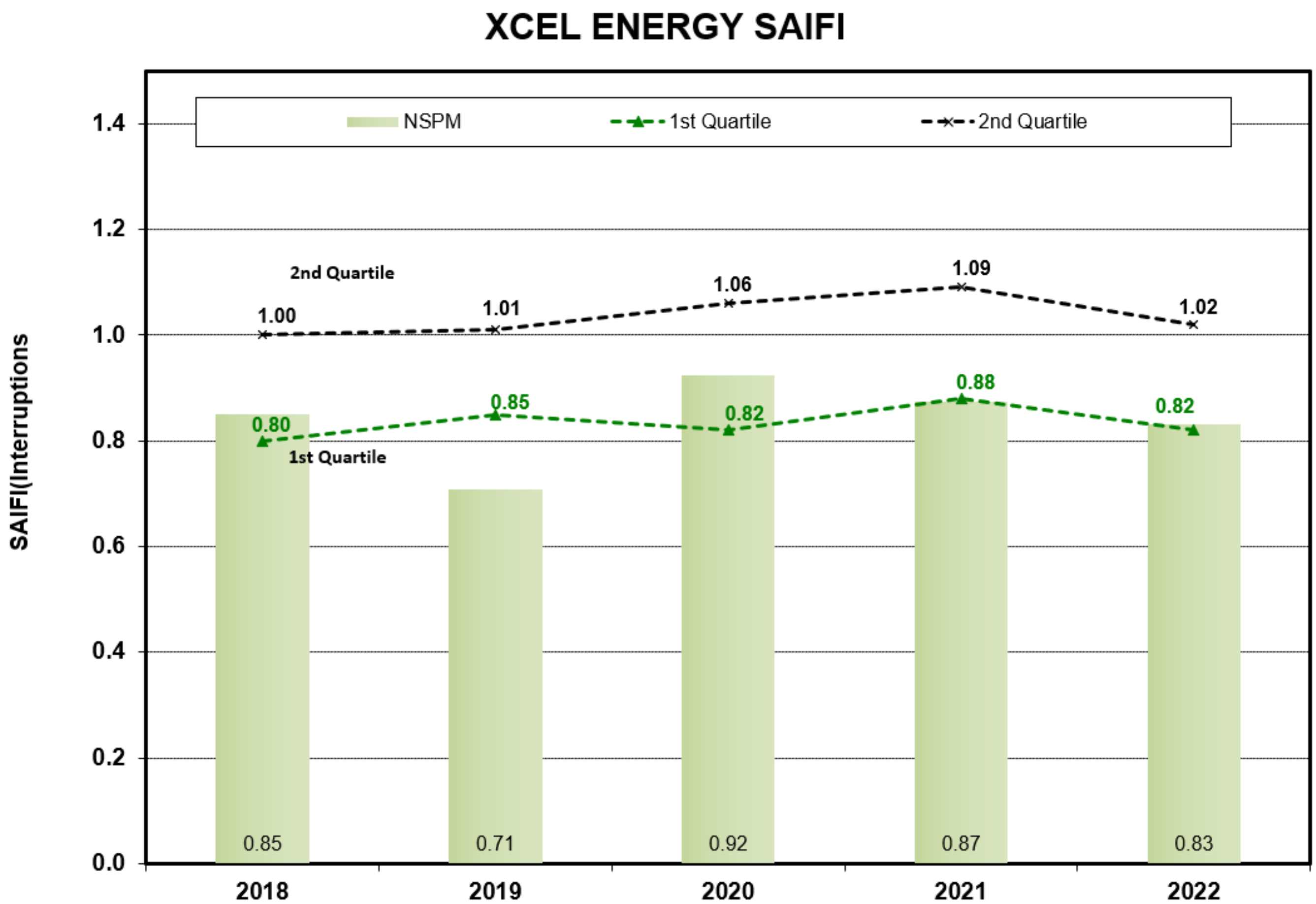
During 2022, NSPM's SAIDI performance was at the 1st quartile performance level.

Graph 21



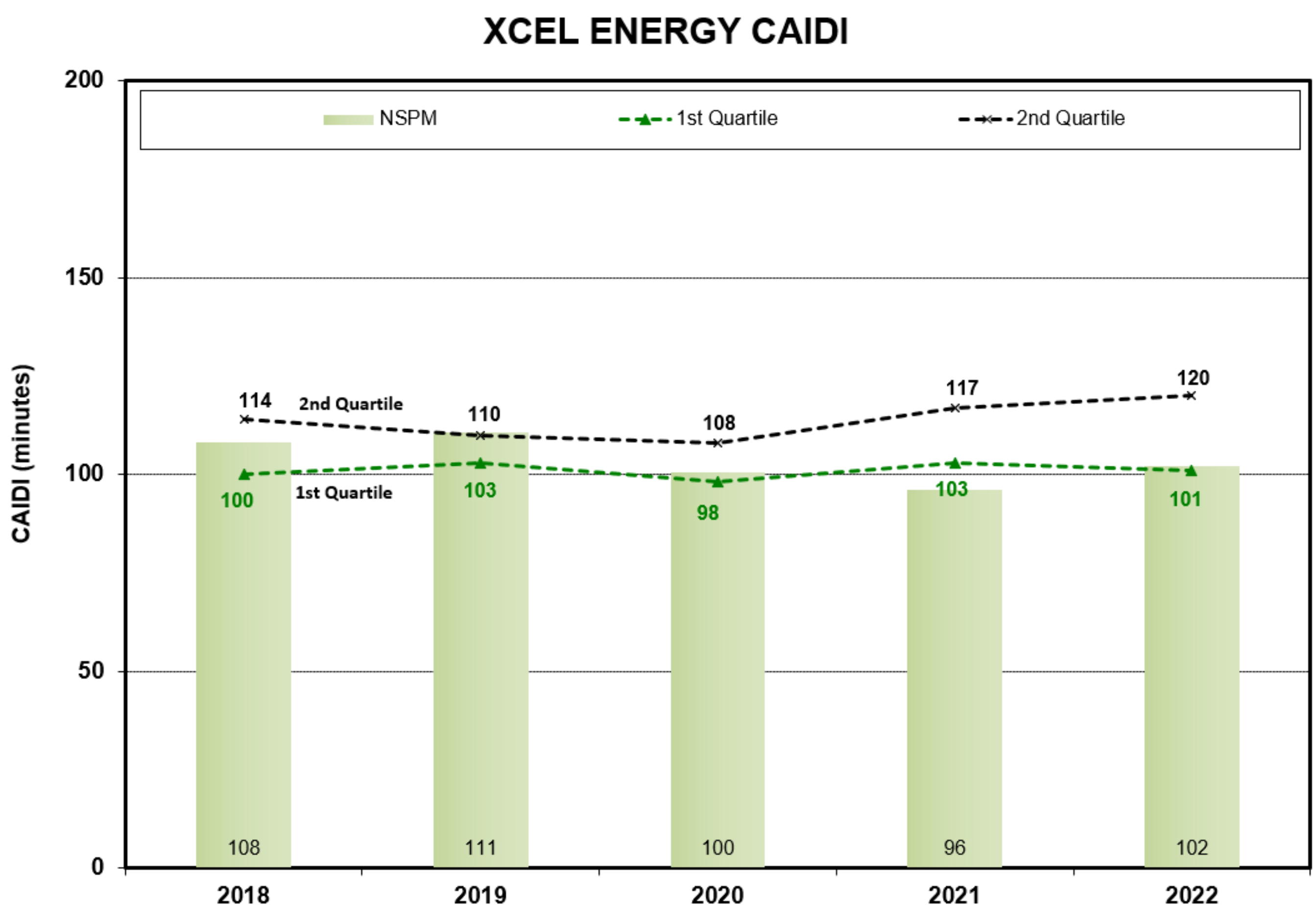
During 2022, NSPM's SAIFI performance was at the 2nd quartile performance level.

Graph 22



During 2022, NSPM's CAIDI performance was at the 2nd quartile level.

Graph 23



Order Point 5 of the Commission's December 5, 2023 Order in Docket No. E002/M-23-73, directed the Company *to provide an analysis of the incremental costs associated with achieving IEEE first quartile performance that includes a discussion of timeframes, costs, and benefits in their SRSQ 2024 filing.*

In compliance with Order Point 5, the Company provides this analysis of incremental costs and considerations to achieve IEEE first quartile performance. Table 25 below provides a historical comparison between the Company's statewide reliability performance indices and the IEEE large utility group first quartile performance level.

Table 25
IEEE Normalized Quartile Comparison

IEEE Normalized Quartile Comparison - System Level
IEEE DWRG Reliability Indices (Large Utility Group)

SAIDI	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average
Minnesota	94.3	84.0	90.0	90.5	75.0	96.1	81.0	99.0	89.0	90.0	88.9
Lrg 1st Qtl	87	85	89	90	76	86	85	84	100	85	86.7
Difference	7.3	-1.0	1.2	0.5	-1.0	10.1	-4.0	15.0	-11.0	5.0	2.2

SAIFI	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average
Minnesota	0.90	0.84	0.83	0.83	0.74	0.89	0.75	0.99	0.92	0.86	0.86
Lrg 1st Qtl	0.83	0.79	0.84	0.91	0.73	0.80	0.85	0.82	0.88	0.82	0.83
Difference	0.07	0.05	-0.01	-0.08	0.01	0.09	-0.10	0.17	0.04	0.04	0.03

CAIDI	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average
Minnesota	104.6	99.7	108.1	108.9	100.9	107.4	108.3	100.3	96.3	104.1	103.9
Lrg 1st Qtl	94	101	98	99	98	100	103	98	103	101	99.5
Difference	10.6	-1.3	10.1	9.9	2.9	7.4	5.3	2.3	-6.7	3.1	4.4

The average difference between the Company's Minnesota reliability performance and the threshold of the IEEE first quartile is less than three percent for SAIDI and SAIFI and less than five percent for CAIDI. However, those relatively small percentages do not accurately capture the significant improvement required to meet a 1st quartile target. For example, if the Company's past SAIFI performance were improved by the average difference of 0.03, first quartile performance would have been achieved in only four out of the last 10 years of available benchmarking. Performance levels consistent with a first quartile target would require roughly a 10-to-15-minute SAIDI improvement, an 0.10 to 0.17 SAIFI improvement, and an eight 8-to-10-minute CAIDI improvement. The 1st quartile group's CAIDI performance has been trending worse over the past 10 years, moving from an average of 98 minutes in the first 5 years of this period to 101 minutes in the most recent 5 years. This has likely been affected to some extent by system automation trends such as FLISR, which tend to reduce SAIDI and SAIFI but increase CAIDI. This is because CAIDI is the ratio of SAIDI to SAIFI and therefore the CAIDI ratio considers only the customers interrupted. The Company's CAIDI performance over the same period has remained relatively consistent, resulting in a narrowing performance difference from 1st quartile. As a result, this analysis focuses primarily on improvement of the SAIDI and SAIFI metrics.

A number of approaches can be used to improve system reliability performance. One of the strategies the Company is currently using is FLISR system deployment. This offers efficiency improvements to SAIDI and SAIFI by automating what has previously been a manual method of in the field switching to restore power to customers on unaffected sections of line. However, service remains interrupted for the customers located on the affected system segment until physical repairs can be completed in the field. Thus, while the overall number of sustained customer outages is reduced, the length of outages experienced by the customers who remain out of service are of a longer average duration which results in an increased (worsened) CAIDI metric. Expanding FLISR at the scale required to target 1st quartile SAIDI and SAIFI performance would likely have diminishing returns because of limited opportunities to apply FLISR and potential lower cost effectiveness in locations beyond what is currently contemplated and approved. For example, additional distribution lines and system capacity may be needed to establish the required system switching ties for FLISR schemes. As a result of those effects, FLISR becomes less cost effective than alternatives when expanded to less-than-prime locations that would be required in order to meet 1st quartile reliability performance.

A number of options were considered to perform a preliminary analysis to evaluate reliability improvement opportunities of the scale required to meet a 1st quartile target. As noted above with FLISR, reliability improvements reach a point of diminishing returns before achieving major gains. Targeted distribution line undergrounding was identified as a practice of interest that has been implemented at several peer investor-owned utilities. This approach would target overhead distribution line sections with the largest impacts to system reliability and convert those facilities from overhead to underground in order to greatly reduce the outage risk from overhead exposures such as vegetation impacts and weather-related events. The Company reviewed five years of outage data across the approximately 13,000 miles of overhead distribution lines and 10,000 miles of underground distribution lines in Minnesota. Roughly 85 percent of customer minutes of service interruption on distribution lines originate on the overhead system despite representing only 55 percent of the total line miles. The Company performed a high level estimate that indicates a move to 1st quartile performance could be achieved in Minnesota by targeting 171 feeders with the highest number of customer interruptions per overhead line mile. These feeders currently have a total of 1,157 miles of overhead distribution lines with an average of over 300,000 customer interruptions per year. In the studied time period, these areas contained 14.5 percent of Minnesota customers experiencing six or more outages per year (CEMI-6) and 21 percent of customers experiencing outages of 24 hours or more (CELI-24). As a result, significant gains could be seen in these customer-centric metrics in addition to the overall system performance indices.

Costs
Costs for targeted undergrounding are highly variable based on location as Rural

locations generally have a lower construction cost per mile than urban locations. This relates to the number of route obstructions, transformers, and services required in each. Costs of undergrounding can be expected to range from $500,000 per mile to as much as $5,000,000 per mile in the case of some high density urban locations. Overall, a program for 1st quartile performance could be expected to cost anywhere between $1 billion and $2 billion in total for the Company's Minnesota service territory. However, if the Commission were interested in moving forward with this targeted undergrounding plan, significant refinement of this preliminary analysis is needed, preferably with the benefit of actual cost information from pilot projects.

Benefits

The Company utilizes the Interruption Cost Estimate (ICE) tool developed by Lawrence Berkeley National Laboratory (LBNL) to estimate benefits to customers. An estimate utilizing 2022 reliability data indicated an average value to underground of $350 per customer interruption. The benefit of avoiding 300,000 customer interruptions per year would be valued at $105 million per year. Further customer value may exist where the avoided outages allow for faster service restoration on other parts of the overhead electric distribution system during large weather events. Those large events are generally what lead to long duration outages because the number of outage jobs significantly exceed the capacity of available field restoration crews.

Operational savings also occur as a result of the underground systems' lower operations and maintenance costs. Based on historic costs, undergrounding these 1,157 miles of lines has the potential to reduce the Company's routine vegetation management costs by several million dollars per year.

Life cycle cost savings can also be expected where proactive replacement of overhead facilities can avoid future costs required for storm damage and age-related replacements. NSPM has averaged over $32 million per year over the past 5 years in major storm restoration and repair costs (mainly associated with overhead distribution lines). The targeted feeders represent 15% of NSPM major storm related outages over this period which suggests a potential $5 million per year savings on those activities. The targeted feeders contain 12% of the Company's distribution poles which suggests potential for a reduction of $3 million per year in pole inspection and replacement costs. The targeted feeders also contain 5,300 distribution transformers identified at significant risk of overload from load changes resulting from electrification and electric vehicle market growth. Costs associated with those future replacement needs along with other distribution line capacity projects could be avoided through appropriate sizing of the newly rebuilt underground facilities. However, the Company does not have an estimate of those capacity related opportunities at this time.

Timing

A shift in system performance of this size and scope would naturally take a number of years to implement. In a rough estimation, the company could begin pilot projects for a potential targeted undergrounding program in late 2025 with a ramp up in the pace of construction activity over the following three years. Completion of investments required to meet 1st quartile performance goals could take nearly 10 years, so a phase-in period would be appropriate for any changes to targets. There are significant unknown considerations for a project of this magnitude at this time, they include but are not limited to: at-scale program costs, labor and material availability, supply chain availability, future cost inflation rates, and future changes in the overall industry performance within the 1st quartile.

The Company views a targeted undergrounding program as a promising opportunity with significant possible benefits. Plans are in development to pilot targeted undergrounding projects in some locations with high reliability value but lower construction and permitting complexity. We will bring this proposal before the Commission when a plan is fully developed.

Order Point 6 of the Commission's December 5, 2023 Order in Docket No E002/M-23-73, requires the Company *to discuss how to lower the difference in SAIDI, SAIFI, and CAIDI between feeders associated with the different customer classes in our 2024 filing, including costs and benefits to implementation. This requirement ends on December 31, 2024, unless the Commission changes or extends it.*

Residential customers make up nearly 90 percent of the statewide reliability indices. As seen in table 13A, commercial and industrial customer classes generally experience fewer service interruptions. These customers are often located in areas with more underground distribution infrastructure and higher load density than residential areas. That higher load density necessitates shorter feeder lengths which also reduces exposure to outage risks. The roughly one percent difference in the CAIDI metric between customer classes does not appear to be significant. The investments and improvements, including costs and benefits, described above to meet 1st quartile reliability targets would serve to narrow the gap in performance through undergrounding distribution feeders that serve primarily residential customers. However, the longer distances involved with residential and rural feeders will limit the opportunity to fully match the reliability performance of commercial and industrial areas.

B. Recommendation for 2024 Standards

Minn. R. 7826.0600, subp. 1, requires the Company *to annually propose standards for SAIFI, SAIDI, and CAIDI.* In addition, *the Commission's December 5, 2023 Order in Docket E002/M-23-73, Order Point 4:*

> *Set(s) Xcel Energy's 2023 statewide Reliability Standard at the IEEE benchmarking 2nd quartile for large utilities. Set Xcel's Southeast and Northwest work center reliability standards at the IEEE benchmarking 2nd quartile for medium utilities. Set Xcel's Metro East and Metro West work center reliability center standards at the IEEE benchmarking 2nd quartile for large utilities. Required Xcel to file a supplement to its 2023 SQSR report 30 days after IEEE publishes the 2023 benchmarking results, with an explanation for any standards the utility did not meet.*

Minn. R. 7826.0200, subp. 13 defines work center as a portion of a utility's assigned service area that it treats as an administrative subdivision for purposes of maintaining and repairing its distribution system, and Xcel Energy applies that definition as our regional service areas. Customer outages on our system are categorized by region and our delivery system work management is tied to these regional divisions. These regions are:

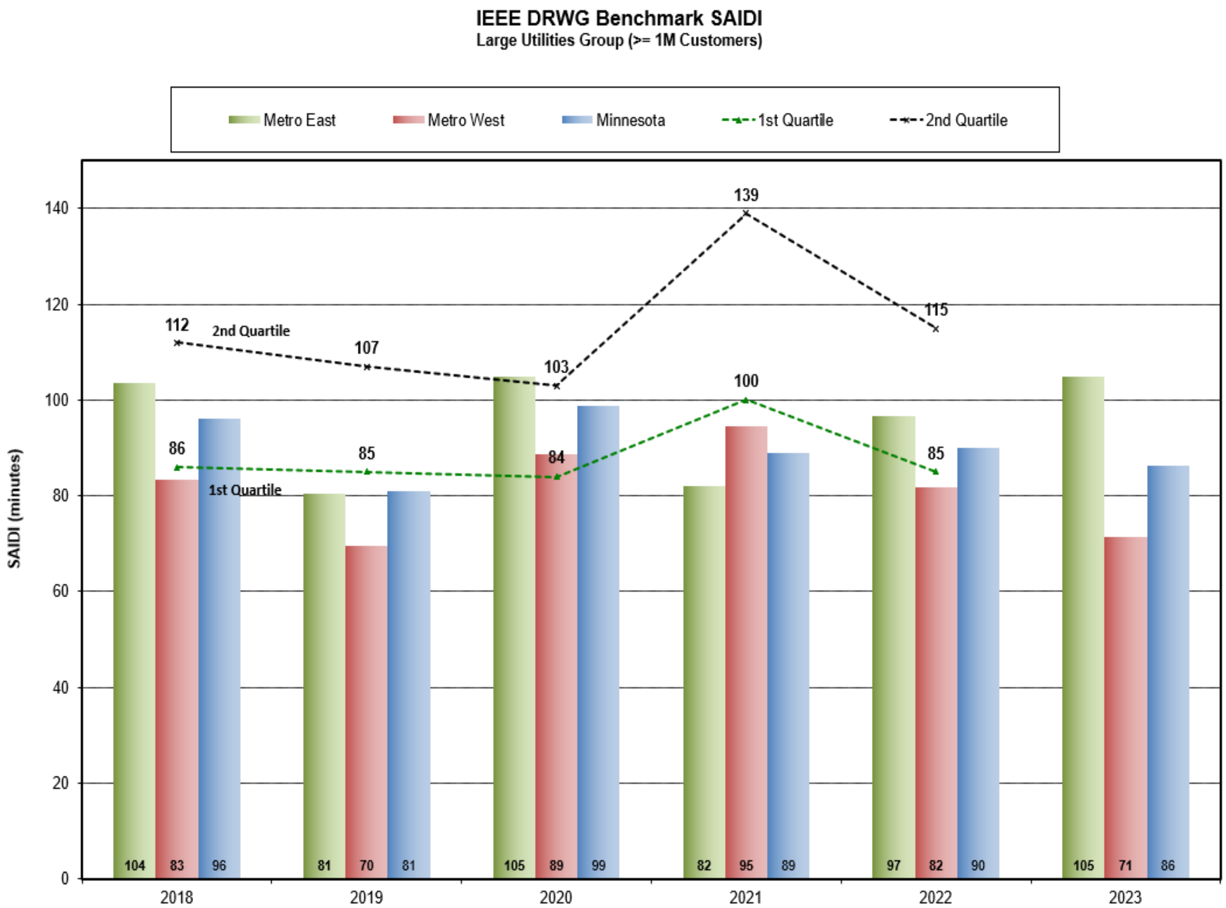
- Metro East,
- Metro West,
- Northwest, and
- Southeast.

Consistent with the Commission's December 5, 2023 Order, we propose 2024 reliability standards as follows: (1) second quartile for our Metro East and Metro West work centers where our peers are other large utilities; and (2) second quartile for our Southeast and Northwest work centers where our peers are medium utilities. Because the IEEE benchmarking data for the previous year is not available until the third quarter of the following year, the 2024 benchmarking data will not be available until the third quarter of 2025.

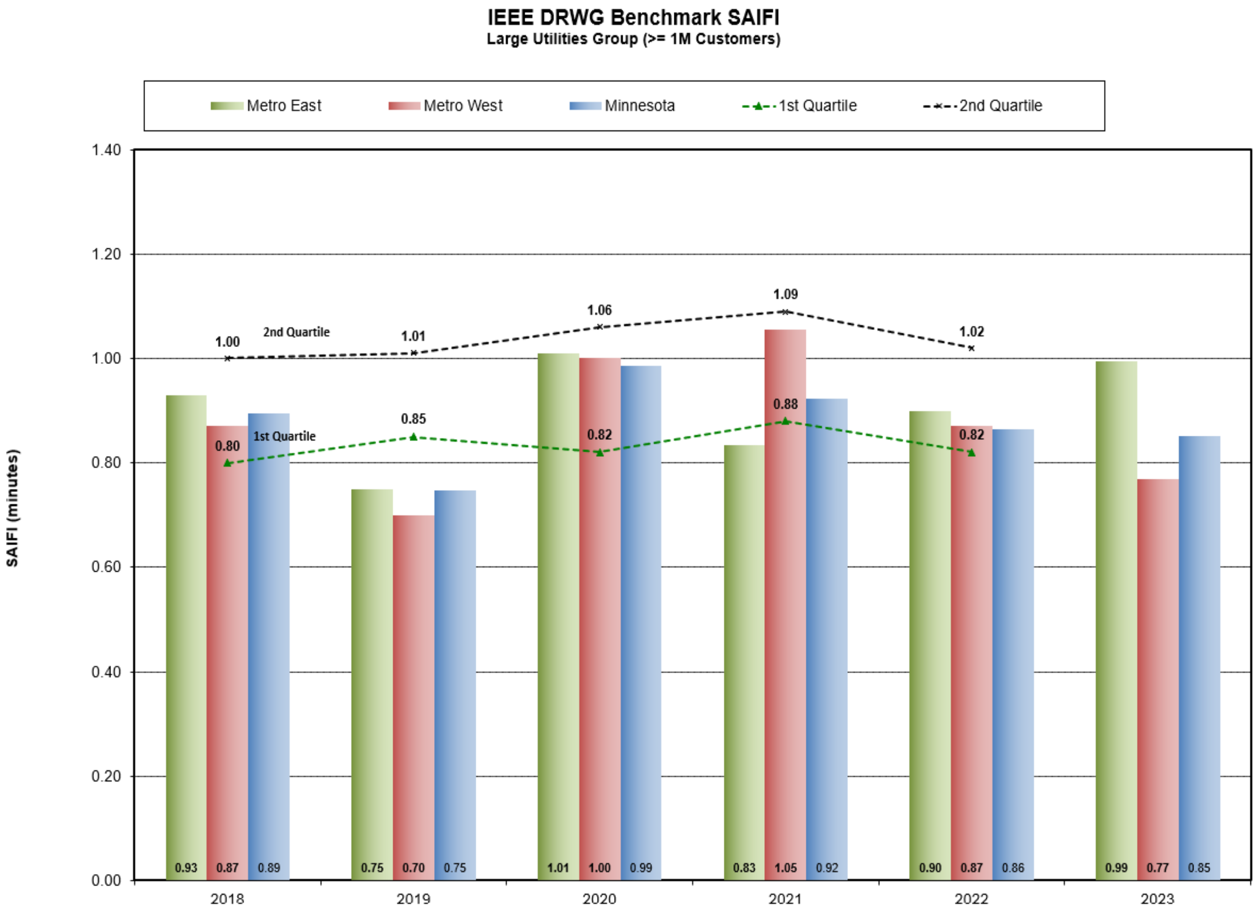
Graphs 24 to 29 below show our historical performance for SAIDI, SAIFI, and CAIDI compared to the corresponding benchmark. Graphs 24 to 26 provide the large utility information for our Metro West and Metro East work centers. Graphs 27 to 29 provide the medium utility information for our Southeast and Northwest work centers.

Graphs 24 to 29 will be updated in our Supplemental filing consistent with the Commission's November 9, 2022 Order, Order Point 4, providing the 2022 IEEE benchmarking results compared to the Company's 2023 reliability. If our proposed 2024 standards are approved, we would submit a similar filing in the summer of 2025.

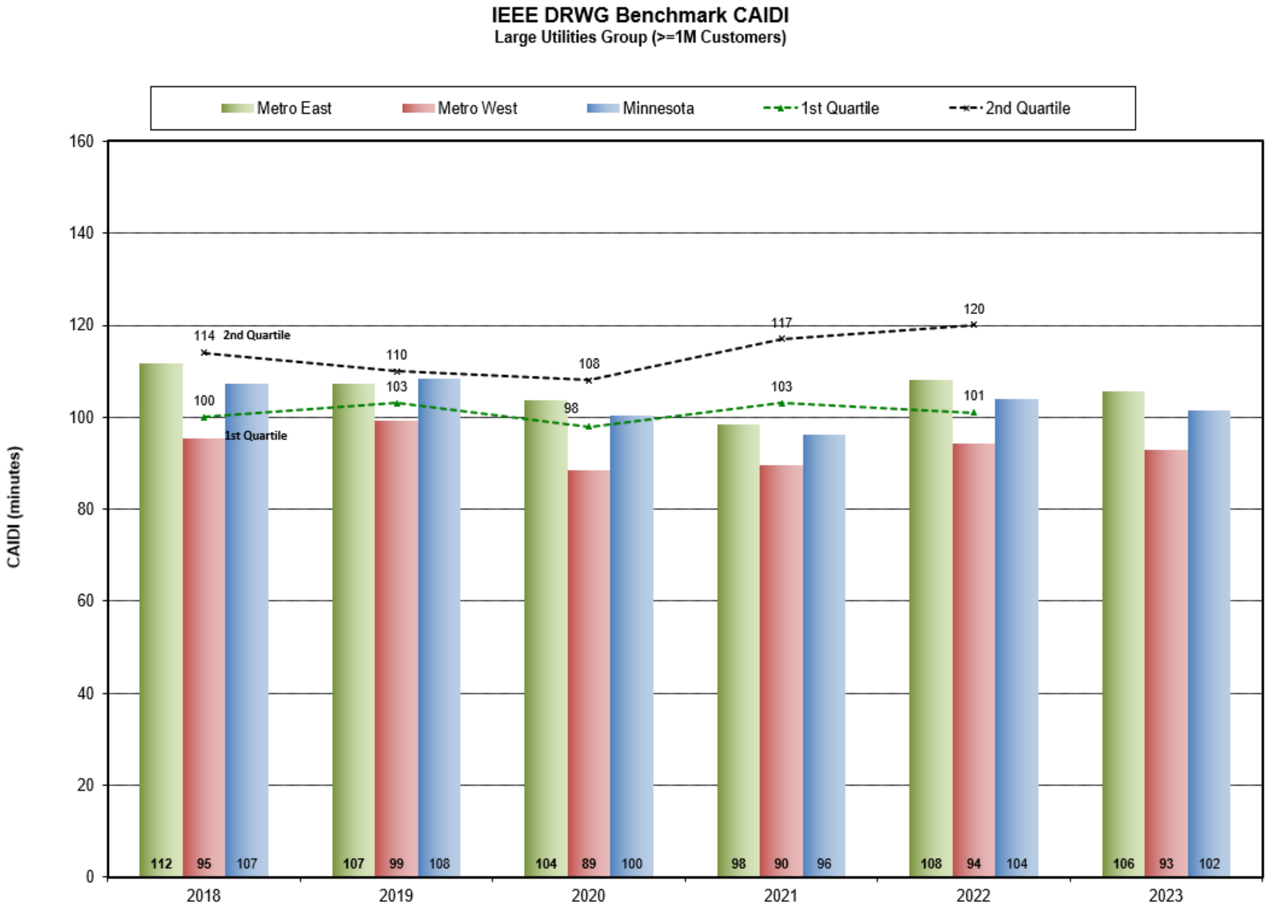
Graph 24



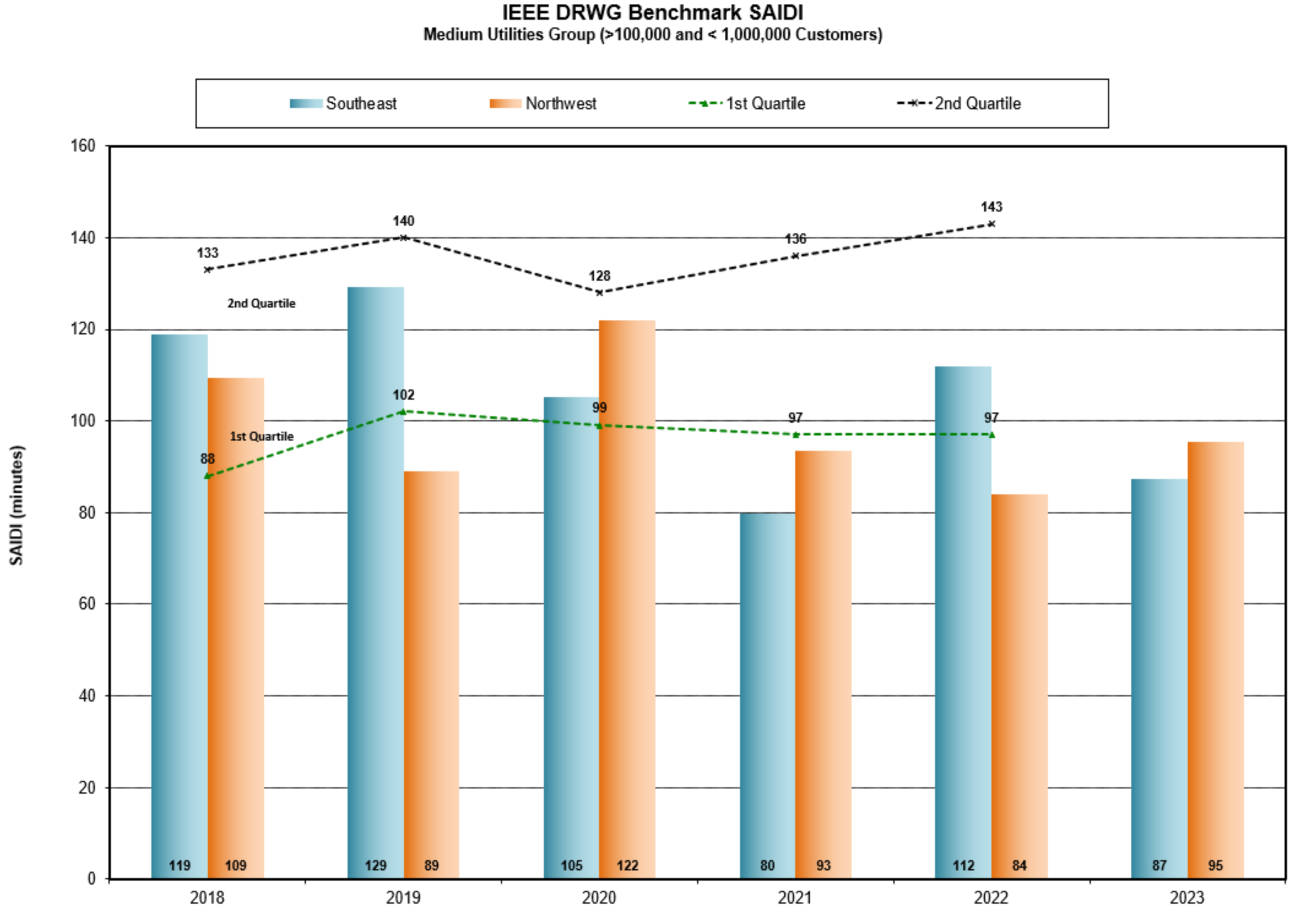
GRAPH 25


IEEE DRWG Benchmark SAIFI
Large Utilities Group (>= 1M Customers)
Metro East
Metro West
Minnesota
1st Quartile
2nd Quartile
SAIFI (minutes)
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2nd Quartile
1st Quartile
1.00
1.01
1.06
1.09
1.02
0.80
0.85
0.82
0.88
0.82
0.93
0.87
0.89
0.75
0.70
0.75
1.01
1.00
0.99
0.83
1.05
0.92
0.90
0.87
0.86
0.99
0.77
0.85
2018
2019
2020
2021
2022
2023

GRAPH 26

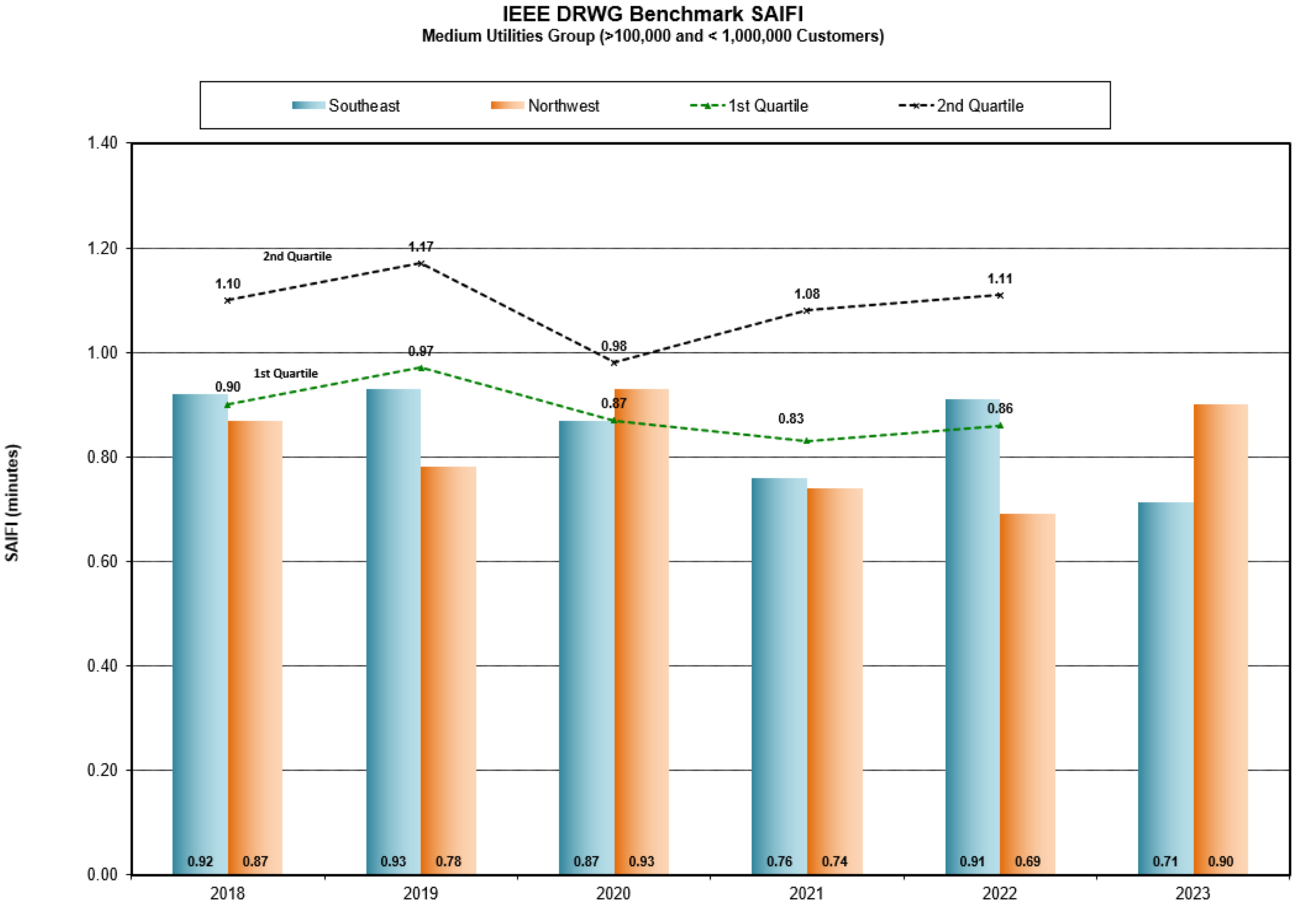

IEEE DRWG Benchmark CAIDI
Large Utilities Group (>=1M Customers)
Metro East
Metro West
Minnesota
1st Quartile
2nd Quartile
CAIDI (minutes)
160
140
120
100
80
60
40
20
0
114 2nd Quartile
110
108
117
120
100
103
98
103
101
1st Quartile
112 95 107
107 99 108
104 89 100
98 90 96
108 94 104
106 93 102
2018
2019
2020
2021
2022
2023

GRAPH 27

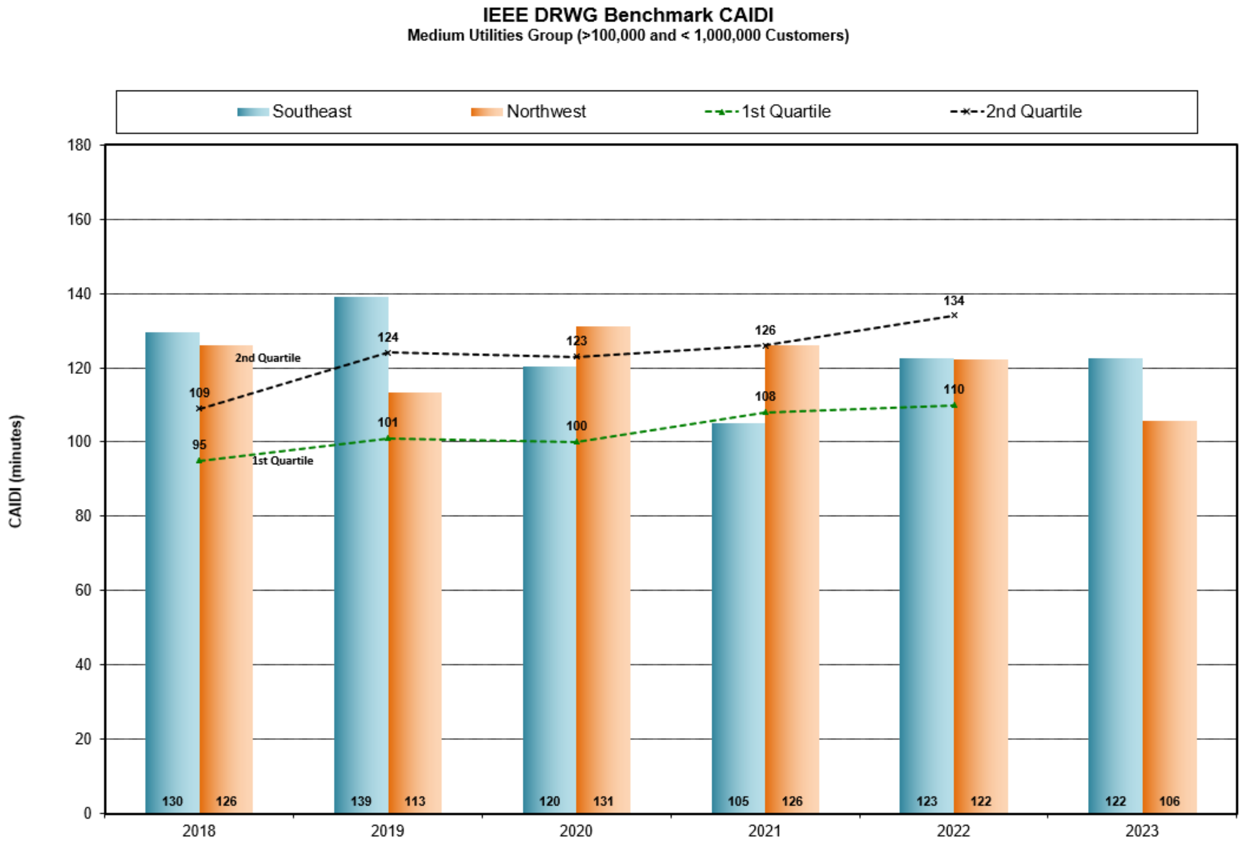

IEEE DRWG Benchmark SAIDI
Medium Utilities Group (>100,000 and < 1,000,000 Customers)
Southeast
Northwest
1st Quartile
2nd Quartile
SAIDI (minutes)
160
140
120
100
80
60
40
20
0
133
140
128
136
143
2nd Quartile
102
99
97
97
88
1st Quartile
119
109
129
89
105
122
80
93
112
84
87
95
2018
2019
2020
2021
2022
2023

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Graph 28



Graph 29



VI. EQUITY ANALYSIS RESULTS

Order Point 3 of the Commission's March 22, 2023 Order, required the Company to:

> *conduct an analysis that examines whether there is a relationship between poor performance on the five identified metrics displayed on the interactive map and equity indicators. Required Xcel to file this analysis with its next service quality report due April 1, 2024.*

Order Point 4 further required:

> *If Xcel's analysis determines there are disparities in any of the five metrics displayed on the map, required Xcel to identify preliminary steps it could take to rectify the disparities and if Commission approval is required, where and when it would expect to file solutions. This should include an analysis of whether modifications to Xcel's Quality of Service Plan are necessary to address any identified disparities. Required*

Xcel to file this preliminary plan with its next service quality report due April 1, 2024.

These requirements are addressed below.

A. TRC Study Background

In compliance with this Order, Xcel Energy contracted with TRC Companies[4] (TRC) to provide an analysis of the five metrics listed on our interactive map -- Customers Experiencing Lengthy Interruptions of 12 hours or more (CELI-12), Customers Experiencing Multiple Interruptions of six or more (CEMI-6), Disconnections, CIP Low Income Participation (CIP LI), and Low Income Energy Affordability Program Participation (LI EAP or Affordability Program) -- to identify if there are any disparities in performance on these five indicators that can be correlated to equity indicators such as income level, percent of people in poverty, or percent people of color. The TRC analysis expands on analysis performed by Dr. Gabriel Chan on behalf of the Just Solar Coalition as part of our last Electric Rate Case.[5] We provide a brief background and summary of the TRC's report below, a copy of which is included here as Attachment Q.

The analysis in Dr. Chan's testimony focused on the correlation between race and utility disconnection; it did not include an analysis of all five metrics required in the Commission's March 2023 Order. In his testimony, Dr. Chan provided analysis that showed, using a linear regression methodology, and after controlling for income and poverty, that disconnections were higher in census block groups with a larger proportion of People of Color (POC). As TRC describes in further detail in their report, their analysis extends the linear regression modeling used by Dr. Chan by 1) including additional information relevant to a customer's ability to pay their bills and disconnections; 2) adding flexibility to the explanatory variables, allowing identification of the ranges of values that different characteristics are associated with in the variables they studied; 3) extending the analysis [as required] to the five metrics reported in our Interactive Map, including outage duration at 12 hours or more, outage frequency at six or more, participation in the CIP Low Income programs, and participation in Low Income Energy Affordability Programs.

TRC utilized data from the American Community Survey provided by the U.S. Census Bureau to extend beyond the key variables in our Interactive Map. They note

[4]Seattle, WA | TRC (trccompanies.com)
[5] Surrebuttal Testimony of Gabriel Chan on Behalf of Just Solar Coalition in Docket No E002/GR-21-630, Dated December 6, 2022.

that some variables are likely to contribute to disconnections such as:

- Home ownership rates along with housing vintage information, used by TRC as proxies for wealth.
- Limited English proficiency, home computer access, and home internet access, used by TRC as proxies for ease of communication.
- Home computer access, home internet access, and distance to the nearest payment center that accepts payments for Xcel Energy, used as proxies for access to payment options.

TRC indicates in their report that leaving out key variables such as those listed above "leads to a bias in modeling known as omitted variable bias, where the estimated impact of included variables is biased due to their correlation with important variables that are left out. In this case, the extent to which percent POC is correlated with other relevant factors will bias the results regarding the impact of percent POC on disconnections and other key metrics." Further, "inclusion of these additional variables significantly reduces omitted variable bias, as well as increasing model fit. These variables similarly provide relevant explanatory power for the other key metrics investigated."

TRC explains how their nonparametric kernel smoothing modeling approach allows for additional insights provided by the key and explanatory variables they incorporated, expanding beyond Dr. Chan's linear regression method that assumes the relationship between variables is a straight line.

B. TRC Study Findings

The TRC analysis indicates that, "in general, Xcel Energy performs well on key electric reliability and service quality metrics, and low-income program participation metrics."[6] The analysis did not identify poor utility performance in any of the five metrics presented on our Interactive Map. However, by including additional variables, TRC was able to identify three metrics where there may be opportunities for improvement and to provide potential recommendations to assess further.

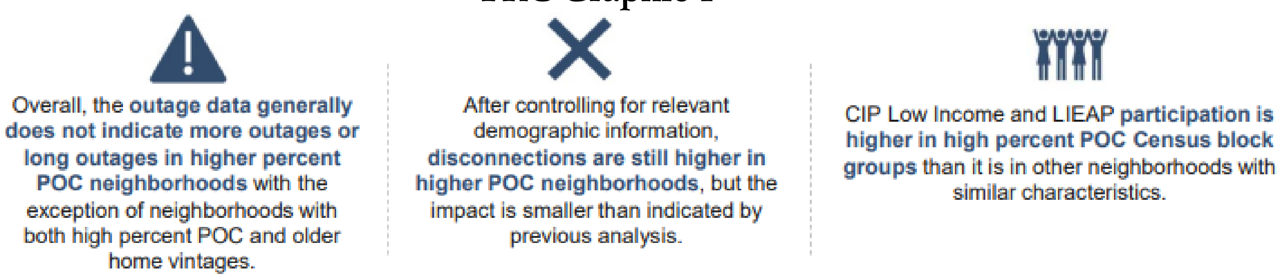
Ultimately, the TRC Study concluded:

> This analysis indicates that in general, Xcel Energy performs well on key electric reliability and service quality metrics, and low-income program participation metrics. The analysis identified three places where there are opportunities for improvement. First, there have been more long-

[6] Attachment Q at 17.

> duration outages in high percent POC communities that also have older housing vintage. There may be an opportunity to assess vegetation management practices in those neighborhoods or assess distribution equipment vintage that could lead to longer outages. Second, disconnections are higher in high percent POC neighborhoods even after controlling for other relevant explanatory variables; we cannot determine from the data if this is due to higher non-payment rates or differential application of disconnection policy. Given the success of enrollment in the LI EAP and CIP LI programs in high percent POC neighborhoods, there may be opportunities to leverage those relationships to identify a path to address the disparity in disconnections. Finally, CIP LI participation may be lower in very-low-income communities. This may present an opportunity to conduct additional outreach or assess program barriers to participation in those communities.[7]

TRC Graphic 1[8]



C. Opportunities for Improvement Identified in the TRC Analysis

Below we address outage duration, disconnections, and CIP LI programs and the opportunities for improvement for these metrics identified by TRC's analysis.

1. CELI-12 (Outage Duration)

TRC's analysis shows that a "comparison across most neighborhoods shows no overall trend in CELI-12 with rising percent POC."[9] However, "among neighborhoods with older homes, CELI rises rapidly with percent POC."[10] In other words, "the outage data generally does not indicate more outages or long outages in higher percent POC neighborhoods, with the exception of neighborhoods with both

[7] Attachment Q at 17.
[8] Attachment Q at ES-1.
[9] Attachment Q at ES-1.
[10] Attachment Q at ES-1.

high percent POC and older vintage homes."[11]The TRC analysis identified this outage duration effect occurred primarily in three areas: North Minneapolis, South Minneapolis, and surrounding downtown St. Paul.[12] TRC indicates there may be opportunity in assessing our vegetation management practices or our distribution equipment vintage to improve this segment of our customer base, particularly in those identified areas.

In order to help understand the challenges in these locations and the opportunities for improvement, we took a deeper look at the outage durations in these areas in the recent past. For example, we know that events that result in 12-hour duration or longer outages are typically significant and occur infrequently. A majority (54 percent) of metro area outages of 12-hour duration or more in the 2019 to 2021 time period resulted from two large storm events on August 14, 2020, and September 17, 2021. Both of those days were classified as major event days and together resulted in over 32,000 customer interruptions of 12 hours or more. The locations most impacted by these two storm events substantially overlap with the three primarily affected areas identify by TRC.

In addition, despite the inclusion of three years of data in the TRC analysis, there is an influence on the data that results from the distinct locations where each major storm's most damaging impacts occurred. The locations most impacted by these two events were therefore not necessarily representative of the full set of the company's system and customer characteristics. As a result, some area's characteristics may be over-represented in the CELI data.

In terms of preliminary steps, the Company could take to address the long-duration outages in the identified communities, as the TRC analysis pointed out, there may be an opportunity to assess vegetation management practices in those neighborhoods or assess distribution equipment vintage that could lead to longer outages. In terms of vegetation management, the Company could evaluate enhanced vegetation management in these areas of concern. Hazard trees located outside the standard clearances are an opportunity to address. Emerald ash borer infestations have generated a higher risk for overhead line impacts in recent years. Homeowners in lower income neighborhoods may be less able to afford insecticide treatment or address dying ash trees on their property. Enhanced vegetation management could work to mitigate these heightened risks to overhead distribution lines.

[11] Attachment Q at ES-1.
[12] Attachment Q at 7.

In terms of distribution equipment vintage, targeted undergrounding may be a solution to bring stronger reliability to older vintage homes served by an older vintage of our distribution network. TRC's analysis found a correlation between income level, POC, and older housing vintage. As part of Order Point 5 of the Commission's December 5, 2023 Order in Docket No. E002/M-23-73, the Company was directed *to provide an analysis of the incremental costs associated with achieving IEEE first quartile performance that includes a discussion of timeframes, costs, and benefits in their SRSQ 2024 filing*. In that discussion, we provide a preliminary analysis of incremental costs associated with achieving IEEE first quartile results in this report (beginning on page 94). This analysis can act as a guidepost to consider distribution equipment upgrades like undergrounding wires, including in these specific communities. The distribution lines identified for undergrounding in our Order Point 5 analysis also serve the same areas identified by in the TRC analysis as having longer outer durations in areas of higher POC (North Minneapolis, South Minneapolis, and surrounding downtown St. Paul). If the Commission is interested in pursuing a targeted undergrounding plan, the Company would require time to fully scope and pilot this project but is open to filing a plan.

Disconnections

Despite recognizing "the success of enrollment in the LI EAP and CIP LI programs in high percent POC neighborhoods," the TRC analysis indicates that after "controlling for relevant demographic information [e.g., income, poverty, and home ownership] disconnections are still higher in higher POC neighborhoods, but the impact is smaller than indicated by previous analysis."[13] The study identifies three potential reasons for these results: 1) a higher rate of non-payment in higher percent POC neighborhoods; 2) potential disparities in disconnection policy; or, 3) disparities in how people in different communities access elements of the disconnect policy—like payment plans.[14]

To try and reach low-income communities with a self-identified higher proportion POC, the Company can utilize current algorithms that identify customers who have not received assistance, are carrying past due balances, and also reside within the identified communities. Targeted outreach about our energy assistance and payment options to these identified areas could include a variety of contact methods that can be tracked for effectiveness. This activity does not require Commission approval. Results of these activities could be tracked and filed in either the next Annual Electric Service Quality Report or added to our Annual Low Income Discount Report.

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[13] Attachment Q at ES-1-2.
[14] Attachment Q at 11.

Another upcoming action by the Company that may reduce disconnections and increase participation in low-income affordability programs is an Automatic Bill Credit Pilot program, developed with the Equity Stakeholder Advisory Group (ESAG) convened under Docket E002/M-22-266, and soon to be filed as a proposed pilot. This pilot aims to reduce energy burden – the share of household income spent on energy. Households with high energy burden are more likely to fall behind on energy bills and be disconnected. This pilot would focus on geographic areas of high electric energy burden and lowering barriers to receiving assistance. In brief, the pilot proposes to provide an automatic bill credit to all households in U.S. Census Block Groups where electric energy burden exceeds four percent, and is designed to reduce electric energy burden to four percent for the median-income household in each Census Block Group, without imposing any of the income qualification or program enrollment requirements that anecdotally discourage low-income households from applying for assistance. If approved, the pilot would run for two years and be evaluated by a third-party evaluator for its success on (among other metrics) reducing disconnection rates.

CIP Low Income Programs

Finally, the TRC analysis indicated the CIP LI program "does not appear to be underserving communities with high percent POC. It may be underserving very low-income communities, which is not unexpected" given other known challenges.[15] Thus, the Company has "an opportunity to improve performance among the lowest-income neighborhoods."[16] The Company is already taking action to try and reach more of our low-income customers. Our CIP LI programs in 2024 include the Low-Income Home Energy Squad, the Home Energy Savings Program, and the Low-Income Multi-Family Building Efficiency Program. In recent years the Company has made changes to our programs to expand participation. These changes focus on reducing landlord/tenant barriers by increasing the percentage of equipment costs covered by rebates for low-income rentals, simplifying the qualification of tenants as low-income, and expanding outreach efforts to better reach building owners.

We will continue to work with stakeholders to expand access to our programs not only through the formal reviews and workshops supported by the Department and Commission, but also through informal channels as we develop relationships and more established communication channels with the entities engaged in providing both energy and non-energy related services to the low-income communities we serve.

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[15] Attachment Q at 14.
[16] Attachment Q at 15.

Modifications to the Energy Conservation & Optimization (ECO) triennial plans are approved through the Department of Commerce. No action is required by the Commission at this time.

VII. CONCLUSION

Xcel Energy is committed to providing our customers with quality, reliable service. We appreciate this opportunity to report our performance to the Commission, and respectfully request that the Commission accept our annual report on safety, reliability, and service quality.

The Company requests a renewal of the temporary variance to Minn. Rule 7820.2500 under the revised timeframe proposed in this filing to account for regulatory review.

Average Cost per Polyphase Disconnect/Reconnect*

	2022 Costs (Docket 22-233)	Current Costs
Pre Lock Call Cost	$0.53	$0.56
Post Lock Call Cost	$3.74	$3.95
Field Personnel Costs - Disconnects	$59.75	$97.77
Field Personnel Costs - Reconnects	$35.85	$97.77
Total Cost	**$99.87**	**$200.04**

*All costs include labor and benefits

Pre Lock Call Cost

Cost	Amount
Average Wage	$18.37
Average Handle Time (Hours)	0.09056
Call Time Cost per Call	$1.66
Handle Time Percentage	52%
Non-Handle Time Cost	$1.54
Total Cost per Call	$3.21
Benefits Included (Assume 73.60%)	$2.36
Total Cost	$5.57
Calls Answered or Received Call Back	10%
Assume 10% of Calls Answered or Received Call Back	$0.56

Post Lock Call Cost

Cost	Amount
Average Wage	$18.37
Average Handle Time (Hours)	0.08032
Call Time Cost per Call	$1.48
Handle Time Percentage	52%
Non-Handle Time Cost	$1.37
Total Cost per Call	$2.85
Benefits Included (Assume 73.60%)	$2.09
Total Cost	$4.94
Calls Answered or Received Call Back	80%
Assume 10% of Calls Answered or Received Call Back	$3.95

Average Cost per Disconnect

Time	1
Amount of Orders Completed	9,256
Time Multiplier	9,256
O&M	$521,268
Cost Per Order	$56.32
Assume 100% of Time Remote Connect Does not Function	$56.32
Cost Per Visit	$56.32
Benefits @ 73.60%	$41.45
Total Cost per Field Visit	$97.77

Average Cost per Reconnect

Time	0.6
Amount of Orders Completed	3,940
Time Multiplier	2,364
O&M	$221,888
Cost Per Order	$56.32
Assume 100% of Customers Can't Use Remote Disconnect	$56.32
Cost Per Visit	$56.32
Benefits @ 73.60%	$41.45
Total Cost per Visit	$97.77

2019 First Call Only Days - 2019 Daily Forecast

From Customer Care Analytics and WFM

Date	Attempts	Response	Calls
2/7/2019	4,921	8%	399
2/8/2019	12,227	5%	587
2/12/2019	9,195	6%	519
3/14/2019	4,610	15%	701
3/15/2019	4,717	9%	413
4/8/2019	5,786	12%	701
4/9/2019	5,962	8%	500
4/10/2019	9,259	6%	599
4/11/2019	3,336	12%	401
4/12/2019	3,714	18%	669
4/15/2019	7,988	18%	1,436
4/16/2019	5,875	12%	721
4/17/2019	8,828	10%	897
6/11/2019	3,663	11%	419
6/12/2019	3,972	8%	325
9/3/2019	4,371	9%	415
Total	**98,424**	**10%**	**9,702**

2019 First Call Attempts by Month

From CC Analytic Solutions - Matt Chad

2019	Attempts
Jan	126,465
Feb	124,014
Mar	125,274
Apr	122,958
May	99,338
Jun	71,022
Jul	71,823
Aug	74,355
Sep	71,622
Oct	
Nov	107,206
Dec	77,234
Average	**97,392**

Assumptions	
Call/Linkback Rate	10%
AHT	326
Productivity Factor	52%
YTD ResCRD Scheduled Hrs	131,734
YTD ResCRD Phone Hours	68,319
Avg Wage	$18.37
	0.090556
Call Time Cost per Call	$1.66
Productivity Factor	$3.21
Benefits Included	$4.58
10%	$0.46

Cost Estimate

2019	1st Call Attempts	Callback/Linkback	Handle Time (Hrs)	Agent Hours	Labor $
Jan	126,465	12,466	1,129	2,177	$39,986
Feb	124,014	12,224	1,107	2,135	$39,211
Mar	125,274	12,349	1,118	2,156	$39,610
Apr	122,958	12,120	1,098	2,116	$38,878
May	99,338	9,792	887	1,710	$31,409
Jun	71,022	7,001	634	1,222	$22,456
Jul	71,823	7,080	641	1,236	$22,709
Aug	74,355	7,329	664	1,280	$23,510
Sep	71,622	7,060	639	1,233	$22,646
Oct	*97,392*	*9,600*	*869*	*1,676*	*$30,794*
Nov	107,206	10,568	957	1,845	$33,897
Dec	77,234	7,613	689	1,329	$24,420
Annual	**1,168,703**	**115,203**	**10,432**	**20,116**	**$369,527**

2019 Minnesota	January	February	March	April	May	June	July	August	September	October	November	December	Total
Calls Associated with a disconnected account	4,784	4,181	6,915	16,180	9,873	1,290	1,921	3,271	3,695	1,802	2,074	2,570	58,556
Average Handle time for all Credit Calls (seconds)	253	260	276	320	294	298	300	291	288	305	301	284	289

2023 Actual

To be multiplied by Productive Labor only, not full wages

Loading Rates	**MN**
Non-Prod	24.02%
Pension & Insurance	31.14%
Benefits Non-Service	5.35%
Payroll Taxes	12.44%
WC - Ins and Other	0.67%
Annual Incentive	0.00%
Total	**73.60%**

Average Cost per Remote Disconnect/Reconnect*

	2022 Costs (Docket 22-233)	Current Costs
Pre Lock Call Cost	$0.53	$0.56
Post Lock Call Cost	$3.74	$3.95
Field Personnel Costs - Disconnects	$8.46	$13.84
Field Personnel Costs - Reconnects	$1.08	$2.93
Total Cost	**$13.80**	**$21.28**

*All costs include labor and benefits

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	Revised - Reply Comments
Time	1
Amount of Orders Completed	9,256
Time Multiplier	9,256
O&M	$521,268
Cost Per Order	$56.32
Benefits @ 73.60%	$41.45
Total Cost per Order - Physical Disconnect	$97.77
Remote Connect Does not Function	
Cost per Physical Disconnect	$97.77
Percent of Time Remote Connect Does not Function	3%
Cost per All Disconnects	$2.93
Incorrect Contact Information	
Total Cost per Order - Physical Disconnect	$97.77
Minutes - Home Visit and Physical Disconnect	39
Cost per Minute	$2.51
Minutes - Home Visit and Virtual Disconnect	29
Cost Per Disconnect	$72.70
Percent of Time Home Visit Needed Due to Incorrect Contact Information	15%
Assume 15% of customers don't have correct phone number	$10.90
Total Cost per All Disconnects	**$13.84**

Average Cost per Reconnect

Time	0.6
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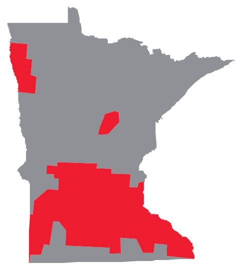
DELIVERING CLEAN, SAFE, RELIABLE ELECTRICITY

INFORMATION SHEET
MINNESOTA

MINNESOTA SERVICE QUALITY AND RELIABILITY

ABOUT XCEL ENERGY MINNESOTA

At Xcel Energy, we provide our customers with safe, clean, reliable electricity at a competitive price.



1.34 million
electric customers served in Minnesota

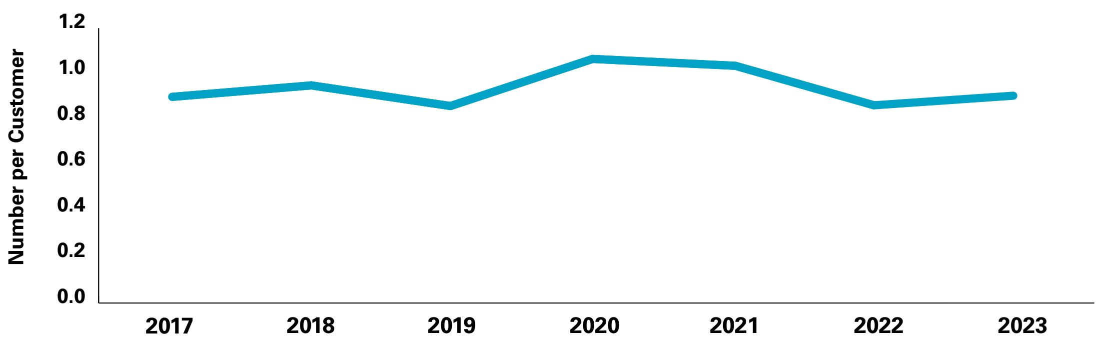
99.984%
Percentage of time Minnesota customers had power in 2023*

86 minutes
Average total time a customer was without power in 2023**

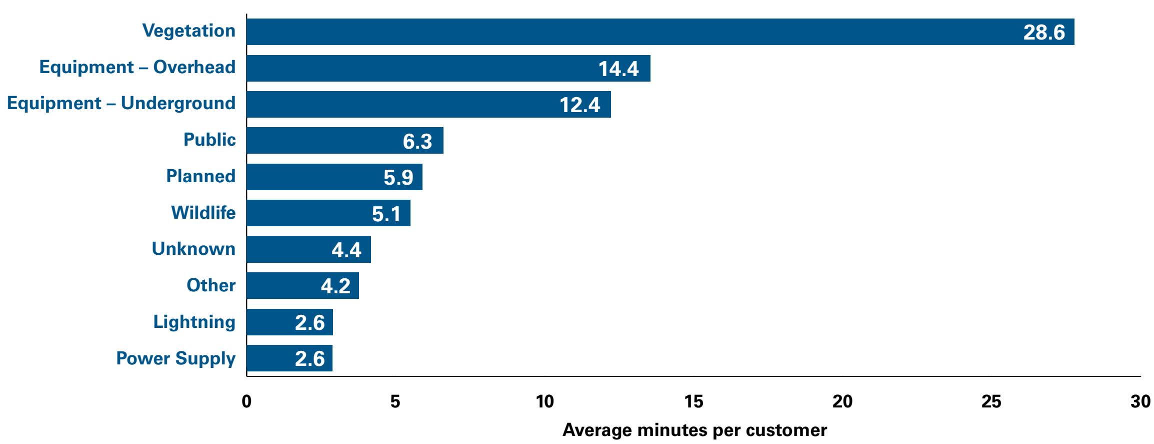
OUR COMMITMENT TO RELIABILITY

Each year, we report on various measurements of electric service reliability. Here are some highlights.

Average number of outages per customer †



Top ten outage causes in 2023 **



* Also known as Average Service Availability Index, or ASAI. Excludes major event days, which include high-impact storms.
** Also known as System Average Interruption Duration Index, or SAIDI. Excludes major event days, which include high-impact storms.
† Also known as System Average Interruption Frequency Index, or SAIFI. Excludes major event days, which include high-impact storms.
All figures represent 2023 averages for all Minnesota customers, unless otherwise noted.

Distribution System Performance Summary

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its transmission and distribution assets. We identify and implement these programs in an effort to assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur.

A. Reliability Management Program Development

Causes and trends for historical outages are monitored and reviewed to identify opportunities to maintain and improve reliability. Investments in reliability improvement are made in addition to other capital programs that provide for adequate capacity to meet customer requirements. Investments for improvement become part of the reliability management program. A reliability core team, consisting of both field and planning functions, monitors system performance and progress against performance targets on a regular basis, taking actions as necessary to ensure the best possible system performance.

High-value, 2023 core reliability programs that are continuing into 2024 include our Feeder Performance Improvement Program (FPIP); proactive mainline and tap cable replacement; substation transformer and breaker condition assessment; and vegetation management (tree trimming). The vegetation management program includes investigation of tree-related events causing large outages to determine if the outage would have been preventable if trimming had occurred the day before the outage. These programs all target primary outage cause codes identified in 2023 and prior years' performance and are expected to support strong system performance. The reliability core team will continue to monitor system performance on a regular basis to determine if additional and/or shifts in these programs should be initiated as the year unfolds.

1. FLISR Reliability Performance

Beginning in 2021 and through 2027, we will continue our long-term Fault Location Isolation and Service Restoration (FLISR) device deployment. FLISR technology has the potential for reducing the number of customers experiencing service interruptions. A five-year history of outages will be evaluated to determine feeders that would benefit and justify FLISR investment. The FLISR devices provide initial reliability benefits once they are operational in the field and additional reliability benefits as we integrate and enable the FLISR devices and functionality with Advanced Distribution Management System (ADMS).

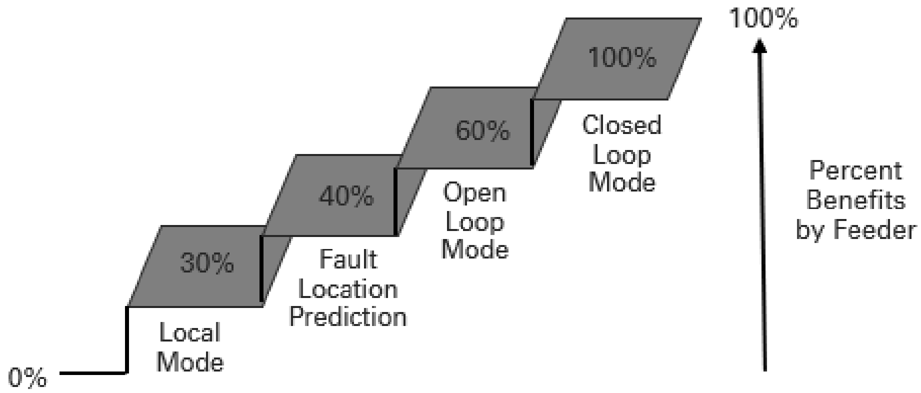
We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked by the System Average Interruption Frequency Index (SAIFI) metric (annual average number of sustained service interruptions per customer served), and shorter duration outages (less than five minutes) are tracked by the Momentary Average Interruption Frequency Index (MAIFI) metric. In essence, we expect that FLISR will transform outages that would have been sustained outages into momentary outages.

As a result, we expect that customers will experience fewer sustained outages, improving our SAIFI performance, while our MAIFI performance will decline. We also expect that FLISR will cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This will negatively impact our CAIDI performance but will be a more positive outage experience for our customers broadly because FLISR will minimize widespread extended outages on the system.

The remote and automated switching capabilities associated with FLISR support a more resilient grid, in addition to reliability benefits. Whether storm-related or due to other unforeseen circumstances that limit employee movement (such as the COVID-19 pandemic), remote operations capabilities provide a means by which to perform critical operations when staff is otherwise limited in numbers or movement. This is a benefit to our customers that is difficult to quantify, but valuable nonetheless.

The outright reliability benefit of FLISR feeders can be difficult to quantify with minimal years and events available for data collection and analyzing. Even without years of system trend data for FLISR feeders, we have still observed a reduction in sustained outages. As an example, a feeder level outage occurred on December 15, 2022 and was caused by a tree branch. A recloser was installed towards the middle part of the feeder as part of the FLISR project. At the time, the recloser had not been commissioned in ADMS; however, the recloser was operational in "local mode" on the feeder. When the tree branch contacted the distribution lines, the recloser opened instead of the feeder breaker, resulting in 1,079 customers that did not have an outage, totaling approximately 52,000 avoided customer minutes out. As the Company enables the full functionality of FLISR in ADMS, it is likely it could result in even greater reliability benefits. Figure J1 is an illustrative representation of the benefits as we enable FLISR functionality across the different phases and as we expand the functionality to a greater number of feeders.

Figure J1: Phases of FLISR Functionality and Benefits



As of the end of 2023, we have 95 devices installed on 54 feeders operating in 'Local Mode'. There are 45 devices installed on 28 feeders operating in 'Open Loop Mode'. Currently we do not have any feeders in 'Closed Loop Mode'. It is only in 'Closed Loop Mode' that we are able to track the reliability performance metric required by Order Point 27(a) of the Commission's July 17, 2023 Order, and we do not yet have any feeders operating in 'Closed Loop Mode.' To reach Closed Loop Mode status will require additional experience and confidence that the technology is working as intended, as it will result in changes to management work practices around fault isolation and restoration. We anticipate having feeders in 'Closed Loop Mode' by the end of the fourth quarter of 2027.

2. Reliability Management Programs – "Star Chart"

After considering the most common failures and their causes, as well as at-risk equipment, we have developed work plans, or programs, to target our reliability investments; we show a summary of these programs in the "Star Chart" below. These programs represent proactive investments in our transmission and distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. These investments are made in addition to other capital investments that provide for adequate capacity to meet customer requirements and to accommodate load switching during outage response to minimize customer impacts.

Table 1
Minnesota Program Summary
Reliability Management Program Impacts (Star Chart)

	Funded Programs	Description	2021 Actuals (k$)	2022 Actuals (k$)	2023 Actuals (k$)	IMPACTS			
						SAIFI	CAIDI	CEMI	Complaints
Reliability	Feeder Perf. Improvement Program (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.	695	3,271	6,501	★		★	★
	Outage Exception Reporting Tool (OH & UG)	OERT process provides automatic notification to area engineers when repeating outage criteria have been met and engineering solutions are implemented to eliminate recurring problems.	250	668	1,548			★	★
	Mainline Cable Replacement, (UG)	Deteriorating non-jacketed cable is failing and causing repeat outages. Proactive and reactive replacement of this cable reduces the outages.	530	4,448	2,207	★			★
	Tap (URD) Cable, (UG)		23,113	31,980	25,628	★	★		★
	Install Automated Switches	These automation solutions reduce restoration times for long lines with long drive times to bring CAIDI in-line with other distribution lines.	0	0	0	★		★	★
	Feeder Infrared Evaluation (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can be repaired prior to causing an outage.	58	45	67	★			
	Vegetation Management (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	29,908	35,522	27,067	★		★	★
Integrity	Pole Inspection & Replacement (Distribution)	Pole Inspections include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Treatment of poles may be included. Based on results poles may be tagged for replacement.	30,208	25,621	29,254	★	★		
	Transmission Substation	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	14,127	15,373	33,763	★			
	Line ELR Work (Transmission)	Identifies lines that have components that have reached their end of life or where significant refurbishment work is needed to enhance system performance and reliability. Project focus may be to extend life of existing asset 20+ years, or to replace and address future capacity upgrade concerns.	5,021	5,200	6,289	★			★

Footnote: The above table reflects multi-year initiatives that are part of the Reliability Management Program (RMP). Information is based on current RMP and is subject to change.

Funding information for previous years is a combination of Capital and O&M dollars; most of the equipment replacement dollars are capital expense while the inspection and testing programs include O&M dollars; O&M dollars and capital for pole replacements and FIRE program are currently estimates since changes are included in broader programs of work (e.g., OH rebuild OH maintenance accounts).

We have indicated the primary performance impacts of these programs with a red star, where applicable; performance impacts include SAIFI , CAIDI, CEMI and Customer Complaints.

3. Management Programs – Key Initiatives

Table 2 below outlines primary program indicators for our key reliability initiative and programs. The actual amount of work completed under each program varies from year-to-year and is based primarily on assessments of those areas requiring the greatest attention, as well as the results of our condition assessment (i.e., the number of deficiencies requiring corrective action). For further description of the programs described in Table 2 below, please see the Star Chart (Table 1) above.

Table 2
Reliability Management Key Initiatives/Programs

Information based on Current RMP and is subject to change

	2023	2022	2021	2020	2019	2018	2017
Vegetation Management Program							
Total Overhead Distribution miles completed	1,128	2,239	2,019	1,606	2,647	2,307	2,417
Total Overhead Transmission miles completed	670	807	754	762	896	768	762
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	247,376	231,463	168,848	184,302	170,994	214,299	145,422
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	444,037	405,731	285,454	286,735	242,158	243,867	277,068
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	2,526	2,591	2,252	2,579	1,158	1,504	1,411
# of Failures(Only on Primary Cable)	1,269	1,429	1,656	1,459	1,301	1,366	1,453
Feeder Infrared Evaluation (FIRE)							
# of Feeders Scanned	126	270	276	259	280	209	248
# of Hot Spots Corrected	18	16	28	66	55	67	71
Feeder Performance Improvement Plans (FPIP)							
Investigations Completed	109	91	97	112	111	108	113
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	54,642	42,330	39,045	40,179	10,312	33,720	17,972
Total Transmission Wood Poles Inspected	1,915	4,329	4,945	3,124	3,381	2,464	4,000

4. Reliability Management Programs – Work Practices

Improvements to existing work practices that the reliability core team members identify and implement are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the duration of outages should they occur, or to reduce the frequency of outages.

As noted in the Reliability Management Work Practices Table 3 below, we assess and prioritize the actions based on a balance of their ability to positively impact reliability (high, medium or low), as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions and update our plan as appropriate.

Table 3
Reliability Management Work Practices

Areas of Opportunity	Key Initiative	Action/ Program	Description	Reliability Impact
Resource Management	Duration	Work Coordination	Introduce a full-time work coordinator to schedule all appointment work when able. The coordinator will be in contact with customers prior-to, during and following their scheduled appointment. This will optimize use resources in support our customers. Better customer service for appointments and resource availability for outage restoration work will result.	Medium
	Frequency	System Integrity	Substation inspection done on every substation specific to identifying vegetation issues, in addition moving to an electronic work collection APP to track and prioritize timely maintenance.	High
Substations	Duration	Equipment Failure Response	Install Mobile subs and connection cables as quickly as possible when customers are out due to equipment failure.	Medium
	Duration	Restore before repair	During a feeder event Control Center personnel restore service to as many customers as possible before making temporary/permanent repairs.	Medium
	Duration	Patrol Optimization	Use of application software to assist manual patrol of outages and momentary outages. This will allow for quicker response and permit a single resource to respond to a greater number of outages or appointments.	Medium
Feeders	Frequency	Intentional Outages	Reduce impact of intentional outage to ensure all steps are being taken to keep the maximum number of customers on. Verify switching to reduce customer counts. Repair while hot instead of taking outage.	Medium
	Frequency & Duration	VM Partnership	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated feeders.	High
	Frequency & Duration	Feeder Patrol Program	Looking for unfused taps and animal protection. Continued use of IR/thermo imaging to identify problems.	Medium
	Frequency	Condition Assessment & Correction	Utilizing UAS (Drone) technology to complete a comprehensive inspection of our worst performing feeders, upon request.	High
	Duration	Restore before repair	Advanced technology going into the control centers and the field.	High
Control Center	Duration	Distribution Operations Model	ADMS (Advanced Distribution Management System) application is live in all NSP Control Centers (4); as the application matures, we are working to locate the fault on the circuit to cut down on the response time.	High
	CAIDI	Model 1/0 Switching	Standard operating procedure to model 1/0 URD as close to real time so the OMS model will reflect the configuration of the URD circuit after it has been switched.	Medium
	CAIDI	Validate Restoration Times	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct.	High
	CAIDI	COM Saturday Crews	Crews metro COM Saturday Crews. 3 Metro East and 3 Metro West	Medium
COM	CAIDI	Backup Crews	Currently negotiating on-call crews for outage response, Friday-Monday to enhance response time to customer outages.	Medium
	SAIFI & CAIDI	Underground Cable Repair	Repair and/or replace cables as directed by engineering	High
	SAIFI	REMS/CEMI Work	Complete work referred by engineering in a timely manner	Low
	SAIFI & CAIDI	On-going Regular Reliability Meeting	Meet regularly to review reliability and share ideas to improve reliability performance.	Low
Reliability Team/ Communications	CAIDI	Continuous Improvement	In 2021, Control Center Leadership is producing a detailed CAIDI report on a monthly basis, the purpose and impact of the report is to call out opportunities for improvement on response, meet with the first responders to develop plans to remove obstacles to response and holding employees accountable to timeliness of response using the data and operator comments.	Medium

5. CEMI Tools

Xcel Energy developed tools that allow us to better track the causes of our CEMI (Customers Experiencing Multiple Interruptions). In conjunction with a mapping tool that identifies customers with multiple outages over a revolving 12 months, we can look at our customers' experiences and then provide a visual representation of those outages in our service territory. Although the metric measures customers who have experienced at least six sustained outages during non-storm days, we can study customers' experiences earlier. This customer centric tool helps highlight customers that have had outages from different causes rather than a single root cause. In other words, this tool does not look at the device that caused the outage, it examines how many times a customer was out of service regardless of the reason.

These tools compliment other programs that help us identify specific equipment issues (for instance, the same device tripping multiple times). The CEMI tools provide the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this tool enhances our reliability planning by helping focus on the customers' experiences.

There are many reasons a customer could have an outage. These causes include downed trees, animal contact, a car hitting a pole, or even a lightning strike. Each one of these causes could show up on a different report for a different piece of equipment that all flow down to the same customer. The CEMI tools allow us to analyze customer experience truly from a customer perspective. These tools also help our efforts in the long term to reduce repeated outages for customers.

The Company provides more detail about CELI metrics, including responding to specific Commission order points, in the body of its Annual Report.

Conclusion

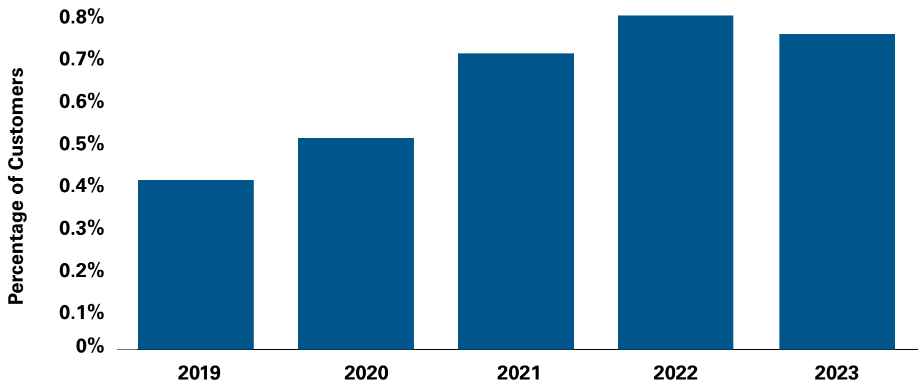
In accordance with Order Point 3 in the Commission's December 12, 2014 Order in Docket No. E-002/M- 14-131 we include this process summary with the data we use to determine areas of greatest impact, develop targeted investment strategies, ensure the execution of annual work plans, and assure reliability and ongoing satisfactory performance of the system as a whole. We know that positive results are a direct reflection of consistent and sustained focus, and as such, believe our reliability management programs and other actions provide a solid foundation on which to deliver and maintain reliable performance of our distribution system.

INFORMATION SHEET

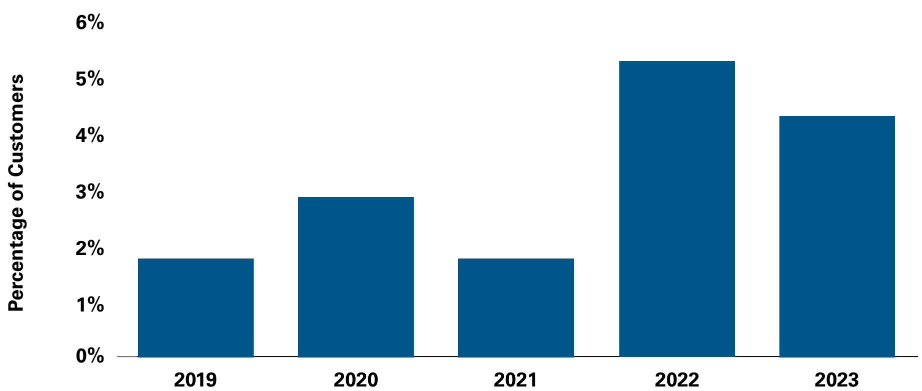
MINNESOTA

DELIVERING CLEAN, SAFE, RELIABLE ELECTRICITY

Percentage of customers with six or more power outages††



Percentage of customers with a power outage lasting twelve or more hours §



The Company has averaged 397 customer complaints per year over the five years from 2019 to 2023. This compares to an average of 371 complaints allowed under the Company's Service Quality Tariff during those years.

2023 Reliability Performance Results

Minnesota	
Average outage duration per customer **	86 minutes
Average number of outages per customer †	0.85
Average outage length***	101.56 minutes

8,256

New residential electric service installations completed in 2023

23 days

Average time to complete a new residential service installation

CONTACT INFORMATION

Customers can contact us and learn more by visiting **xcelenergy.com**, calling customer service at **800-895-4999**, or finding us on Facebook or Twitter.

If you believe we have not resolved your concerns, you may contact the Minnesota Public Utilities Commission, Consumer Affairs Office at 651-296-0406 or 800-657-3782 or email at consumer.puc@state.mn.us at any time.

†† Also known as Customers Experiencing Multiple Interruptions, or CEMI, includes major event days

§ Also known as Customers Experiencing Lengthy Interruptions, or CELI, includes major event days

** Also known as System Average Interruption Duration Index, or SAIDI. Excludes major event days, which include high-impact storms.

† Also known as System Average Interruption Frequency Index, or SAIFI. Excludes major event days, which include high-impact storms.

*** Also known as Customer Average Interruption Duration Index, or CAIDI. Excludes major event days, which include high-impact storms.

Xcel Energy®

Metro East

	Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Total (All levels, All Causes included) Outages	Customers Affected	Customer Mins Out	Bulk Power Supply (All Causes, Distribution Substation, Transmission Substation, and Transmission Line levels) Outages	Customers Affected	Customer Mins Out	Unplanned (All levels, No "Planned" Cause Includes Bulk Power Supply) Outages	Customers Affected	Customer Mins Out	Planned (All levels, "Planned" Cause only Includes Bulk Power Supply) Outages	Customers Affected	Customer Mins Out
	[Protected Data Begins																	
1			White Bear Lake	3.10	992.6	320	40	4,231	1,352,946	0	0	0	40	4,231	1,352,946	0	0	0
2			Stillwater	2.21	741.0	335	121	4,534	1,516,875	0	0	0	120	4,533	1,516,736	1	1	139
3			Cottage Grove	2.42	654.0	270	4	46	12,426	0	0	0	4	46	12,426	0	0	0
4			Inver Grove Heights	3.91	530.5	136	35	7,821	1,060,533	0	0	0	35	7,821	1,060,533	0	0	0
5			Empire Twp	4.16	434.5	105	13	4,103	428,865	1	977	112,619	13	4,103	428,865	0	0	0
6			White Bear Lake	4.81	425.8	89	100	11,390	1,009,146	0	0	0	99	11,386	1,008,730	1	4	416
7			White Bear Lake	1.63	407.8	250	90	4,263	1,064,281	0	0	0	90	4,263	1,064,281	0	0	0
8			Mounds View	3.20	373.6	117	38	5,271	615,238	0	0	0	38	5,271	615,238	0	0	0
9			White Bear Lake	1.31	371.5	284	40	1,740	493,409	0	0	0	40	1,740	493,409	0	0	0
10			Rosemount	1.51	355.6	236	18	285	67,203	0	0	0	18	285	67,203	0	0	0
11			Saint Paul	0.67	344.0	516	2	6	3,096	0	0	0	2	6	3,096	0	0	0
12			Saint Paul	1.36	324.3	239	20	2,076	496,894	0	0	0	20	2,076	496,894	0	0	0
13			Taylors Falls	2.65	321.1	121	84	5,301	642,861	0	0	0	84	5,301	642,861	0	0	0
14			Lent	1.59	320.8	202	163	5,264	1,062,494	0	0	0	163	5,264	1,062,494	0	0	0
15			Farmington	2.96	310.1	105	4	409	42,794	1	137	15,824	4	409	42,794	0	0	0
16			North Oaks	1.31	269.2	206	38	1,484	304,991	0	0	0	38	1,484	304,991	0	0	0
17			Lino Lakes	2.51	259.4	103	48	10,461	1,079,467	1	4,151	153,587	48	10,461	1,079,467	0	0	0
18			Saint Paul	3.15	256.8	82	29	7,186	585,709	0	0	0	28	7,181	585,372	1	5	337
19			Saint Paul	1.67	247.4	148	27	3,531	522,436	0	0	0	26	3,530	522,375	1	1	60
20			White Bear Lake	1.38	227.0	164	19	1,069	175,248	0	0	0	19	1,069	175,248	0	0	0
21			Shoreview	2.98	222.1	74	17	3,190	237,376	2	2,129	107,510	17	3,190	237,376	0	0	0
22			New Scandia	2.67	221.6	83	114	8,233	683,006	2	5,896	356,332	114	8,233	683,006	0	0	0
23			New Brighton	2.37	215.9	91	26	5,225	476,777	0	0	0	26	5,225	476,777	0	0	0
24			Lino Lakes	1.29	214.3	166	49	5,142	852,819	0	49	2,548	49	5,142	852,819	0	0	0
25			Saint Paul	1.24	207.9	167	40	2,670	446,771	0	0	0	40	2,670	446,771	0	0	0

(1) Based on **Jan 1-Dec 31, 2023**, year-end normalized data (IEEE Op Co Level)
"Total" includes all causes, all levels
"Bulk Power Supply" includes Distribution Substation, Transmission Substation, and Transmission Line levels, all cause codes
"Unplanned" includes all levels and no outages with a primary cause code of "Intentional/Planned", Includes Bulk Power Supply outages
"Planned" includes all levels and only outages with a primary cause code of "Intentional/Planned", Includes Bulk Power Supply outages

Metro East Poor Performing Feeders (2)
Based on performance **Sept 2022 to Aug 2023**, Major Event Days are included

CMO: customer minutes out

Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Reasons for Poor Performance	Operational Changes Made, Considering or Planned
		Afton	1.9	1373.9	721.90	75.6% of CMOs are due to vegetation/storms. 12.6% of CMOs are due to overhead equipment.	Total scope of work includes installing 4 tripsavers, installing/replacing 18 fuses, and replacing 1 overloaded transformer.
		Hugo	2.0	635.0	310.10	60% of CMOs are due to vegetation/storms. 12.7% of CMOs are due to overhead equipment.	Replacing 3 end of life reclosers with viper reclosers. Also installing tripsavers on smaller taps.
		Stillwater	3.4	1486.5	431.58	63.6 % of CMOs are due to vegetation. 16.2% of CMOs are unknown but likely vegetation, and 10.6% of CMOs are due to overhead equipment.	Replacing 1 end of life recloser with a viper recloser. Also installing 7 tripsavers. Tree trimming scheduled for 2024
		Stillwater	3.9	1357.2	347.11	72.9% of CMOs are due to vegetation. 13.2% of CMOs are due to overhead equipment.	Referred to tree trimming. Installing 6 tripsavers and 1 viper recloser. FLISR on this feeder
		Hugo	2.3	609.3	264.59	52.5% of CMOs are due to vegetation. 15.3% of CMOs are due to overhead equipment.	Installing 2 viper reclosers and 2 tripsavers. Referred to tree trimming.
		White Bear Lake	2.6	741.6	288.69	77.5% of CMOs are due to vegetation, lightning, or wildlife.	Installing 9+ tripsaver reclosers on taps. FLISR being implemented on feeder for faster isolation and restorations. Referred for tree trimming
		Afton	1.8	325.9	180.71	55.4% of CMOs are due to vegetation or lightning. 21.6% of CMOs are due to overhead equipment.	Installing 5 tripsaver reclosers on taps. Recently installed 1 viper recloser. Installing various wildlife protection.
		Lindstrom	1.6	292.3	179.93	59.7% of CMOs are due to vegetation. 13% of CMOs are due to undergound equipment. 9% of CMOs are due to public damage. 40% fo CMOs occurred during a winter storm on 4/1/23 (all vegetation related).	Install 3 tripsaver reclosers on fused taps and install viper recloser on 3 phase tap. Consider substation project. Referred for tree trimming.
		Arden Hills	1.7	506.1	293.66	41.6% of CMOs are due to vegetation. 22.1% of CMOs are due to underground equipment.	Install 5 tripsaver reclosers on fused taps. Add various wildlife protection. Consider replacing headend cable. Referred for tree trimming.
Protected Data Ends]							

(2) Distribution outages only, Major Event Days are included

Metro West

							All levels, All Causes included **Total**			All Causes, Distribution Substation, Transmission Substation, and Transmission Line levels **Bulk Power Supply**			All levels, No "Planned" Cause Includes Bulk Power Supply **Unplanned**			All levels, "Planned" Cause only Includes Bulk Power Supply **Planned**		
	Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out
	[Protected Data Begins																	
1			Mound	4.07	770.7	190	35	4,937	935,661	1	1,205	125,320	35	4,937	935,661	0	0	0
2			Minneapolis	1.00	527.0	527	1	1	527	0	0	0	1	1	527	0	0	0
3			Minnetonka	3.42	475.4	139	58	5,314	737,893	1	1,557	303,615	58	5,314	737,893	0	0	0
4			Minneapolis	5.69	436.3	77	21	3,912	299,731	0	0	0	21	3,912	299,731	0	0	0
5			Minnetonka	4.30	414.6	96	24	3,041	293,095	0	0	0	24	3,041	293,095	0	0	0
6			Deephaven	2.36	392.2	166	52	2,270	377,708	1	964	206,296	52	2,270	377,708	0	0	0
7			Minneapolis	3.71	363.4	98	27	1,132	110,848	0	0	0	27	1,132	110,848	0	0	0
8			Deephaven	2.38	341.8	144	88	4,151	596,136	1	1,749	346,302	88	4,151	596,136	0	0	0
9			Saint Anthony	1.31	311.7	238	19	1,467	348,823	0	0	0	19	1,467	348,823	0	0	0
10			Bloomington	2.75	310.5	113	29	2,284	257,736	0	0	0	29	2,284	257,736	0	0	0
11			Mound	3.21	256.8	80	88	8,767	700,230	1	2,717	282,568	88	8,767	700,230	0	0	0
12			Brooklyn Center	2.94	250.6	85	65	7,514	640,357	0	0	0	65	7,514	640,357	0	0	0
13			Minnetonka	3.62	247.6	68	33	11,415	781,089	0	0	0	33	11,415	781,089	0	0	0
14			Cologne	2.33	245.6	105	49	3,347	352,636	0	0	0	49	3,347	352,636	0	0	0
15			Edina	3.41	240.6	71	38	5,244	369,811	0	0	0	38	5,244	369,811	0	0	0
16			Tonka Bay	1.70	237.5	139	75	2,764	385,186	1	1,623	162,300	75	2,764	385,186	0	0	0
17			Minnetonka	1.12	235.0	210	25	988	207,461	1	885	189,390	25	988	207,461	0	0	0
18			Spring Park	3.19	233.6	73	65	6,292	460,473	2	3,948	262,392	65	6,292	460,473	0	0	0
19			Minnetonka	3.27	231.3	71	37	4,637	327,576	1	1,409	140,900	37	4,637	327,576	0	0	0
20			Savage	2.43	228.7	94	14	2,379	224,160	0	0	0	14	2,379	224,160	0	0	0
21			Minnetonka	2.41	224.8	93	76	4,025	374,667	0	0	0	76	4,025	374,667	0	0	0
22			Long Lake	0.55	224.6	409	50	722	295,132	0	0	0	50	722	295,132	0	0	0
23			Golden Valley	0.76	223.1	293	26	597	174,653	0	0	0	26	597	174,653	0	0	0
24			Minneapolis	4.49	216.0	48	22	4,228	203,220	0	0	0	19	4,193	200,369	3	35	2,851
25			Savage	1.41	198.1	140	8	134	18,819	0	0	0	8	134	18,819	0	0	0

(1) Based on **Jan 1-Dec 31, 2023**, year-end normalized data (IEEE Op Co Level)
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Metro West Poor Performing Feeders (2)
Based on performance **Sept 2022 to Aug 2023**, Major Event Days are included **CMO: customer minutes out**

Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Reasons for Poor Performance	Operational Changes Made, Considering or Planned
		Bloomington	3.34	896.99	268.29	44.9% of CMOs due to vegetation. 40.4% of CMOs are due to planned work.	Adding tripsavers and fuses for reclosing capability and better coordination.
		Brooklyn Center	1.55	207.43	134.10	59.6% of CMOs due to vegetation or storms. 13% of CMOs are unknown but likely vegetation related, and 10.4% of outages are due to underground equipment.	Reclosers are being installed for FLISR implementation and tripsavers are being installed.
		Deephaven	3.40	519.11	152.48	77.3% of CMOs due to vegetation.	Reframe ~24 structures from narrow 3-phase construction to standard tangent build. Replace structures as needed. Trim corridor per capatilization policy to accomodate wider construction.
		Bloomington	3.72	344.96	92.81	56.4% of CMOs due underground equipment. 26.3% of CMOs due to vegetation.	Replacing 2 sections of unjacketed cable that failed.
		Bloomington	2.44	629.33	257.41	65.5% of CMOs due to vegetation. 10.7% of CMOs due to underground equipment.	Targeted underground project to break long radial tap into smaller taps.
Protected Data Ends]							

(2) Distribution outages only, Major Event Days are included

Northwest

							All levels, All Causes included			All Causes, Distribution Substation, Transmission Substation, and Transmission Line levels			All levels, No "Planned" Cause Includes Bulk Power Supply			All levels, "Planned" Cause only Includes Bulk Power Supply		
							Total			**Bulk Power Supply**			**Unplanned**			**Planned**		
	Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out
	[Protected Data Begins																	
1			Sumter Twp	3.18	544.2	171	12	175	29,929	0	0	0	12	175	29,929	0	0	0
2			Dayton	2.51	358.8	143	30	3,038	434,105	0	0	0	30	3,038	434,105	0	0	0
3			Danube	1.02	296.8	291	7	303	88,150	0	0	0	6	293	87,293	1	10	857
4			Borup	1.01	280.7	278	2	105	29,191	0	0	0	2	105	29,191	0	0	0
5			Rogers	2.23	232.6	104	55	12,963	1,349,829	0	0	0	54	12,924	1,348,503	1	39	1,326
6			Greenwald	1.12	212.4	189	7	328	62,023	1	291	51,798	7	328	62,023	0	0	0
7			Montrose	2.14	196.1	92	44	4,249	388,865	1	1,986	127,104	44	4,249	388,865	0	0	0
8			Starbuck	1.03	174.9	170	14	1,228	208,963	2	1,175	192,758	14	1,228	208,963	0	0	0
9			Monticello	3.07	151.3	49	7	1,401	69,164	1	457	11,425	7	1,401	69,164	0	0	0
10			St Cloud	1.30	149.1	115	24	3,184	366,492	0	0	0	22	3,136	356,622	2	48	9,870
11			Rockville	1.32	148.7	113	24	857	96,655	0	0	0	24	857	96,655	0	0	0
12			Sartell	1.08	140.1	130	25	3,975	514,965	0	0	0	25	3,975	514,965	0	0	0
13			Belview	1.25	131.0	105	20	426	44,677	0	0	0	20	426	44,677	0	0	0
14			Cokato	1.06	129.0	122	13	1,394	169,827	0	0	0	13	1,394	169,827	0	0	0
15			Waite Park	1.03	127.1	124	7	508	62,810	0	0	0	7	508	62,810	0	0	0
16			Saint Michael	1.95	125.8	65	79	10,055	648,845	1	3,607	173,136	76	10,036	647,602	3	19	1,243
17			Becker	1.00	125.5	125	1	1	125	0	0	0	1	1	125	0	0	0
18			Sauk Rapids	1.72	119.3	69	49	6,501	450,683	0	0	0	48	6,500	450,618	1	1	65
19			Westport	0.92	115.7	125	6	48	6,018	0	0	0	6	48	6,018	0	0	0
20			Howard Lake	1.42	112.3	79	24	1,459	115,284	1	1,028	65,792	24	1,459	115,284	0	0	0
21			Raymond	0.68	108.3	159	35	602	95,950	0	0	0	33	579	94,621	2	23	1,329
22			Clarkfield	0.18	105.5	571	15	111	63,408	0	0	0	14	104	63,141	1	7	266
23			Sedan	1.24	105.4	85	5	88	7,486	1	71	6,035	5	88	7,486	0	0	0
24			Paynesville Twp	0.75	103.6	138	65	1,944	268,404	0	0	0	65	1,944	268,404	0	0	0
25			Sauk Rapids	1.11	103.3	93	9	2,580	240,045	0	0	0	9	2,580	240,045	0	0	0

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Northwest Poor Performing Feeders (2)
Based on performance Sept 2022 to Aug 2023, Major Event Days are included **CMO: customer minutes out**

Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Reasons for Poor Performance	Operational Changes Made, Considering or Planned
		Paynesville	2.15	1,073.15	499.18	45.4% of CMOs due to vegetation. 34.6% of CMOs due to overhead equipment	Replacing 2 fuses with tripsavers, rebuilding 12 miles of conductor, and replacing various overhead equipment over 5 mile span.
		Paynesville	2.43	813.66	334.80	46.6% of CMOs due to overhead equipment. 27.4% or CMOs due to vegetation.	Rebuilding distribution and transmission lines. Also replacing poles and crossarms along 2 mile stretch.
		Buffalo	1.47	256.257	174.32	34.7% of CMOs due to storm, 35.8% of CMOs due to overhead equipment, and 11.2% of CMOs due to public damage.	Replacing various cutouts, arrestors, and insulators. Also rereferred to tree trimming.
		Averill	1.61	268.89	167.01	The main contributor to CMOS this year was an overhead recloser that feeds a long section of line.	The feeder was recently split into a smaller section. Will continue to monitor performance and rebuild worst performing tap.
Protected Data Ends]							

(2) Distribution outages only, Major Event Days are included

	Southeast						All levels, All Causes included			All Causes, Distribution Substation, Transmission Substation, and Transmission Line levels			All levels, No "Planned" Cause Includes Bulk Power Supply			All levels, "Planned" Cause only Includes Bulk Power Supply		
							Total			**Bulk Power Supply**			**Unplanned**			**Planned**		
	Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out	Outages	Customers Affected	Customer Mins Out
	[Protected Data Begins																	
1			Iona	2.84	678.2	239	13	585	139,705	0	0	0	13	585	139,705	0	0	0
2			Saint Clair	2.39	463.3	194	23	1,433	277,982	0	0	0	22	1,423	273,846	1	10	4,137
3			Florence Twp	3.85	402.1	104	48	2,788	291,105	3	2,152	134,826	48	2,788	291,105	0	0	0
4			Wabasha	1.15	360.2	312	35	1,001	312,638	0	0	0	34	982	312,150	1	19	488
5			Jasper	3.24	346.8	107	37	3,477	371,735	0	0	0	37	3,477	371,735	0	0	0
6			Mankato	2.00	308.2	154	2	2	308	1	1	79	2	2	308	0	0	0
7			Red Wing	3.57	302.6	85	38	7,618	645,386	0	0	0	38	7,618	645,386	0	0	0
8			Mankato	1.14	292.8	258	21	2,009	517,679	0	0	0	21	2,009	517,679	0	0	0
9			Mankato	1.58	291.3	185	45	2,564	473,320	0	0	0	45	2,564	473,320	0	0	0
10			Tracy	1.71	269.7	158	31	1,684	265,889	0	0	0	30	1,678	265,320	1	6	570
11			Lake Wilson	1.06	266.3	250	3	183	45,798	0	0	0	3	183	45,798	0	0	0
12			Cleveland	1.04	256.9	246	13	519	127,688	0	0	0	13	519	127,688	0	0	0
13			Castle Rock Twp	2.00	250.3	125	4	164	20,526	1	82	16,400	3	82	4,126	1	82	16,400
14			North Mankato	1.52	245.6	161	16	1,744	281,465	0	0	0	16	1,744	281,465	0	0	0
15			North Mankato	1.41	245.0	174	12	1,158	201,109	1	811	165,444	11	1,149	199,420	1	9	1,689
16			Lime Twp	0.84	225.0	268	16	451	121,066	0	0	0	16	451	121,066	0	0	0
17			Hatfield	2.57	217.6	85	17	144	12,186	1	57	3,876	17	144	12,186	0	0	0
18			Mankato Twp	1.99	211.2	106	2	1,868	197,920	1	935	57,970	2	1,868	197,920	0	0	0
19			Balaton	2.53	195.5	77	12	1,377	106,559	0	0	0	12	1,377	106,559	0	0	0
20			Mount Pleasant Twp	1.41	188.9	134	21	269	36,079	0	0	0	21	269	36,079	0	0	0
21			Gillford Twp	1.32	174.2	132	31	1,022	135,346	0	0	0	31	1,022	135,346	0	0	0
22			Nerstrand	2.34	174.1	74	26	1,190	88,619	1	507	5,070	26	1,190	88,619	0	0	0
23			Mankato	2.17	172.2	79	14	3,460	274,318	1	1,601	99,262	14	3,460	274,318	0	0	0
24			Hampton	1.31	163.9	125	38	1,492	187,207	0	0	0	38	1,492	187,207	0	0	0
25			Wanamingo Twp	1.21	157.9	131	12	75	9,789	1	61	6,845	12	75	9,789	0	0	0

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Southeast Poor Performing Feeders (2)
Based on performance **Sept 2022 to Aug 2023**, Major Event Days are included

CMO: customer minutes out

Feeder ID	Substation	City	SAIFI	SAIDI	CAIDI	Reasons for Poor Performance	Operational Changes Made, Considering or Planned
		Pipestone	5.31	618.12	116.41	57.8% of CMOs are due to overhead equipment. 19.3% of outages are due to public damage.	Reclosers on the feeder are responsible for the majority of interruptions, and they are working as intended. One recloser was replaced with a new viper recloser. Trees need trimming and bad poles were replaced.
		Iona	2.04	665.44	326.20	86.9% of CMOs are due to overhead equipment. Galloping is a repeated issue.	Interset poles between long spans and install spacers to limit galloping.
Protected Data Ends]							

Line	Begin Date	Begin Time	Duration Hours	Duration Minutes	Cause	Remedial Action
[PROTECTED DATA BEGINS						
	1/19/2023	8:36	0	46	Equipment / Wire Down	Repair down wire
	2/1/2023	14:40	1	5	Vegetation / Tree on Line	Remove tree (that was felled by a tree trimming contractor) and inspect conductor for damage
	2/8/2023	5:30	0	2	Unknown	Patrol not requested
	3/16/2023	18:16	1	38	Winter Storm / Potential Galloping	Patrolled and no damage found
	3/31/2023	23:39	3	56	Winter Storm / Potential Galloping	Patrolled and no damage found
	4/1/2023	2:56	2	10	Winter Storm / Potential Galloping	Patrolled and found galloping that was occuring - Evaluate for future mitigation project
	4/1/2023	3:09	1	5	Winter Storm / Potential Galloping	Isolated galloping section until galloping subsided
	4/1/2023	3:51	0	6	Winter Storm / Potential Galloping	Isolated galloping section until galloping subsided
	4/5/2023	17:51	0	4	Winter Storm / Potential Galloping	Patrolled and no damage found
	4/11/2023	1:32	3	15	System Protection	Substation breaker opened for a real time overload, causing a different Substation breaker to trip.
	5/1/2023	10:06	3	59	Substation Equipment	Fixed problem in Substation
	5/12/2023	0:26	1	44	Storm / Substation Equipment	Fixed problem in Substation
	5/29/2023	19:23	0	53	Storm	Non-Xcel line patroled and line re-energized
	6/25/2023	1:31	12	9	Storm / Substation Equipment	Fixed jumper failure in Substation - crew needed to mobilize man lift to the site
	6/28/2023	17:16	1	19	Vegetation / Tree on Line	Remove tree and inspect conductor for damage
	6/29/2023	16:59	0	10	Storm	Patrolled and no damage found
	7/19/2023	17:16	2	4	Storm / Wire Down	Repair down wire
	7/27/2023	21:30	1	12	Storm	Patrolled and no damage found
	8/11/2023	14:53	1	26	Vegetation / Tree on Line	Remove tree and inspect conductor for damage
	8/24/2023	1:00	0	2	Equipment / Distribution	Remove distribution underbuild line that was found wrapped around one phase of the transmission line
	9/29/2023	9:30	0	44	External / Public Damage	Patrol found fresh burn mark on bottom phase and cited possible contact with construction equipment
	12/20/2023	14:27	1	14	Mis-Operation	Switching procedure was reviewed and completed in correct order

PROTECTED DATA ENDS]

	Feeder	Primary Event #	Begin Time	Completion Time	Duration Min.	Customers Out	Region	Email sent to CAO
	[PROTECTED DATA BEGINS							
	JANUARY = 9 total qualifying event, 1 event with no email							
1		2313852	01/03/23 09:26	01/03/23 10:53	87	779	Southeast	X
2		2314368	01/04/23 02:45	01/04/23 05:10	145	2,131	Southeast	X
3		2314433	01/04/23 06:23	01/04/23 07:40	77	2,600	Metro East	X
4		2314988	01/04/23 11:37	01/04/23 12:56	79	1,030	Southeast	X
5		2315458	01/05/23 06:47	01/05/23 08:35	108	1,534	Metro West	X
6		2316871	01/10/23 18:19	01/10/23 20:03	104	1,655	Metro West	X
7		2317300	01/12/23 00:22	01/12/23 01:34	72	3,339	Metro East	
8		2314411	01/04/23 05:47	01/04/23 06:51	64	816	Metro West	X
9		2314989	01/04/23 11:37	01/04/23 12:46	69	403	Southeast	X
	FEBRUARY = 15 total qualifying events, 0 events with no email							
1		2323240	2/5/2023 2:36	2/5/2023 4:05	89	2,482	Northwest-St Cloud_NT	X
2		2324314	2/7/2023 19:08	2/7/2023 20:11	7	606	Northwest	X
3		2324309	2/7/2023 19:08	2/7/2023 20:11	7	41	Northwest	X
4		2324306	2/7/2023 19:08	2/7/2023 20:11	63	714	Northwest-St Cloud_NT	X
5		2325350	2/10/2023 18:32	2/10/2023 21:56	204	811	Faribault_Mankato_SE	X
6		2325363	2/10/2023 18:32	2/10/2023 19:34	63	302	Faribault_Mankato_SE	X
7		2325356	2/10/2023 18:32	2/10/2023 19:34	62	1,601	Faribault_Mankato_SE	X
8		2325351	2/10/2023 18:32	2/10/2023 19:34	62	935	Faribault_Mankato_SE	X
9		2325972	2/13/2023 11:25	2/13/2023 15:44	258	944	Edina_MW	X
10		2325974	2/13/2023 11:27	2/13/2023 14:00	153	2,600	Edina_MW	X
11		2326807	2/14/2023 19:08	2/14/2023 21:40	152	961	Minnetonka_MW	X
12		2329365	2/23/2023 4:38	2/23/2023 6:07	89	2,584	White Bear_ME	X
13		2331665	2/27/2023 5:10	2/27/2023 7:47	157	2,128	St Paul_ME	X
14		2331675	2/27/2023 5:19	2/27/2023 6:47	87	2,584	White Bear_ME	X
15		2332651	2/28/2023 9:33	2/28/2023 10:41	67	2,407	White Bear_ME	X
	MARCH = 13 total qualifying events, 1 event with no email							
1		2337209	3/16/2023 18:17	3/16/2023 19:55	98	566	Faribault_Mankato_SE	X
2		2341042	3/30/2023 19:19	3/30/2023 20:25	66	1,985	White Bear_ME	X
3		2341814	3/31/2023 22:11	4/1/2023 1:45	214	1,194	Minnetonka_MW	X
4		2342027	3/31/2023 22:54	4/1/2023 1:07	133	3,232	Mpls_Mtka_Plymouth_MW	
5		2342023	3/31/2023 22:54	4/1/2023 2:17	203	1,955	Mpls_Mtka_Plymouth_MW	X
6		2342093	3/31/2023 23:09	4/1/2023 1:01	112	1,503	Maple Grove_MW	X
7		2342096	3/31/2023 23:09	4/1/2023 1:03	114	964	Maple Grove_MW	X
8		2342264	3/31/2023 23:32	4/1/2023 1:59	146	886	Maple Grove_MW	X
9		2341697	3/31/2023 20:43	4/1/2023 2:54	371	1532	Metro West	X
10		2342001	3/31/2023 10:49	4/1/2023 12:55	846	885	Metro West	X
11		2342234	3/31/2023 23:24	4/1/2023 23:59	755	1605	Metro West	X
12		2342291	3/31/2023 23:39		236	611	Southeast	X
13		2342000	3/31/2023 22:49	5/1/1900 0:00	122	25	Metro West	X
	APRIL = 58 total qualifying events, 1 event with no email							
1		2342421	4/1/2023 0:07	4/1/2023 4:27	260	4,987	Northwest-St Cloud_NT	X

2		2342434	4/1/2023 0:20	4/1/2023 2:34	134	2,939	White Bear_ME	X
3		2342657	4/1/2023 0:35	4/1/2023 2:58	143	2,120	White Bear_ME	X
4		2342795	4/1/2023 0:50	4/1/2023 4:01	191	2,176	Winona_SE	X
5		2342819	4/1/2023 0:54	4/1/2023 2:54	120	2,613	Newport_ME	X
6		2342875	4/1/2023 1:00	4/1/2023 5:10	250	1,845	Newport_ME	X
7		2342908	4/1/2023 1:03	4/1/2023 4:36	213	2,716	St Paul_ME	X
8		2342929	4/1/2023 1:04	4/1/2023 9:29	505	1,428	White Bear_ME	X
9		2357982	4/1/2023 1:06	4/1/2023 8:16	430	579	St Paul_ME	X
10		2342987	4/1/2023 1:09	4/1/2023 3:29	140	2,003	Edina_MW	X
11		2342992	4/1/2023 1:09	4/1/2023 3:53	164	2,502	St Paul_ME	X
12		2343035	4/1/2023 1:12	4/1/2023 8:35	443	1,718	White Bear_ME	X
13		2343116	4/1/2023 1:21	4/1/2023 8:01	400	1,071	Edina_MW	X
14		2343188	4/1/2023 1:25	4/1/2023 11:15	589	1,166	Newport_ME	
15		2343236	4/1/2023 1:28	4/1/2023 10:11	523	3,695	Newport_ME	X
16		2343265	4/1/2023 1:29	4/1/2023 16:34	905	2,113	White Bear_ME	X
17		2343427	4/1/2023 1:43	4/1/2023 4:44	180	1,879	Mpls_Mtka_Plymouth_MW	X
18		2343422	4/1/2023 1:43	4/1/2023 5:13	210	1,368	Mpls_Mtka_Plymouth_MW	X
19		2343423	4/1/2023 1:43	4/1/2023 5:14	211	3,093	Mpls_Mtka_Plymouth_MW	X
20		2343542	4/1/2023 1:58	4/1/2023 5:36	217	2,098	Maple Grove_MW	X
21		2343581	4/1/2023 2:03	4/1/2023 3:15	71	1,420	St Paul_ME	X
22		2343612	4/1/2023 2:08	4/1/2023 5:54	226	2,108	White Bear_ME	X
23		2343647	4/1/2023 2:10	4/1/2023 5:04	174	2,063	White Bear_ME	X
24		2352110	4/1/2023 2:10	4/1/2023 13:28	678	1,166	White Bear_ME	X
25		2341872	4/1/2023 2:23	4/1/2023 7:15	292	2,909	Minnetonka_MW	X
26		2344124	4/1/2023 3:02	4/1/2023 10:14	432	1,843	Mpls_Mtka_Plymouth_MW	X
27		2344460	4/1/2023 3:37	4/1/2023 5:53	136	1,158	Newport_ME	X
28		2354111	4/1/2023 3:37	4/1/2023 5:53	136	2,614	Newport_ME	X
29		2344457	4/1/2023 3:37	4/1/2023 5:53	136	484	Metro East	X
30		2354115	4/1/2023 3:37	4/1/2023 5:53	136	600	Newport_ME	X
31		2344520	4/1/2023 3:37	4/1/2023 5:53	136	662	Newport_ME	X
32		2344456	4/1/2023 3:37	4/1/2023 5:53	136	341	Newport_ME	X
33		2344462	4/1/2023 3:38	4/1/2023 4:39	60	2,003	Edina_MW	X
34		2344739	4/1/2023 4:27	4/1/2023 6:10	103	3,332	Edina_MW	X
35		2351523	4/1/2023 4:43	4/1/2023 6:12	89	3,345	Newport_ME	X
36		2351521	4/1/2023 4:43	4/1/2023 6:12	88	347	Newport_ME	X
37		2354276	4/1/2023 4:43	4/1/2023 6:12	89	285	Newport_ME	X
38		2344909	4/1/2023 4:51	4/1/2023 8:19	207	1,939	Maple Grove_MW	X
39		2344972	4/1/2023 5:03	4/1/2023 12:10	427	735	Newport_ME	X
40		2345097	4/1/2023 5:26	4/1/2023 9:53	266	1,847	Newport_ME	X
41		2357985	4/1/2023 8:56	4/1/2023 9:53	54	579	Newport_ME	X
42		2345655	4/1/2023 7:23	4/1/2023 12:27	304	2,319	Newport_ME	X
43		2354656	4/7/2023 14:50	4/7/2023 15:57	66	1,555	Mpls_Mtka_Plymouth_MW	X
44		2355691	4/10/2023 12:07	4/10/2023 14:32	145	1,140	Faribault_Mankato_SE	X
45		2355691	4/10/2023 12:07	4/10/2023 14:32	145	1,153	Faribault_Mankato_SE	X
46		2356110	4/11/2023 0:03	4/11/2023 1:44	100	1,648	Northwest-St Cloud_NT	X
47		2356128	4/11/2023 5:03	4/11/2023 7:10	127	509	Faribault_Mankato_SE	X

48		2356767	4/12/2023 4:39	4/12/2023 6:11	92	1,507	Mpls_Mtka_Plymouth_MW	X
49		2357369	4/12/2023 22:15	4/12/2023 23:46	91	780	Mpls_Mtka_Plymouth_MW	X
50		2357422	4/12/2023 22:41	4/13/2023 0:48	126	833	Edina_MW	X
51		2357420	4/12/2023 22:41	4/13/2023 0:48	127	833	Edina_MW	X
52		2357421	4/12/2023 22:41	4/12/2023 23:59	77	2,098	Maple Grove_MW	X
53		2365991	4/15/2023 13:22	4/15/2023 14:54	92	1,520	Maple Grove_MW	X
54		2359534	4/16/2023 1:53	4/16/2023 3:22	89	2,191	Newport_ME	X
55		2361327	4/17/2023 13:37	4/17/2023 14:57	80	2,541	Mpls_Mtka_Plymouth_MW	X
56		2363722	4/20/2023 20:37	4/20/2023 22:16	99	2,715	Minnetonka_MW	X
57		2366581	4/28/2023 18:47	4/28/2023 20:00	73	1,174	White Bear_ME	X
58		2367313	4/30/2023 15:22	4/30/2023 16:56	94	1,149	Faribault_Mankato_SE	X
MAY = 18 total qualifying events, 0 events with no email								
1		2367650	5/1/2023 10:05	5/1/2023 14:05	240	1174	Northwest-St Cloud_NT	X
2		2367668	5/1/2023 10:05	5/1/2023 14:05	85	71	Northwest-St Cloud_NT	X
3		2367647	5/1/2023 10:05	5/1/2023 14:05	497	1	Northwest-St Cloud_NT	X
4		2368810	5/3/2023 14:18	5/3/2023 15:46	88	1,770	White Bear_ME	X
5		2369976	5/5/2023 9:20	5/5/2023 10:52	92	1,554	Minnetonka_MW	X
6		2371151	5/8/2023 14:54	5/8/2023 15:57	63	1,006	Winona_SE	X
7		2372564	5/11/2023 6:04	5/11/2023 10:10	246	1412	Minnetonka_MW	X
8		2373108	5/12/2023 0:27	5/12/2023 2:11	104	1,205	Minnetonka_MW	X
9		2373099	5/12/2023 0:27	5/12/2023 2:11	104	2,717	Minnetonka_MW	X
10		2373101	5/12/2023 0:27	5/12/2023 2:11	104	1,799	Minnetonka_MW	X
11		2373100	5/12/2023 0:27	5/12/2023 2:11	104	2,367	Minnetonka_MW	X
12		2373117	5/12/2023 0:27	5/12/2023 2:11	104	1,972	Minnetonka_MW	X
13		2379709	5/25/2023 2:31	5/25/2023 3:45	74	4644	Mpls_Mtka_Plymouth_MW	X
14		2380858	5/27/2023 5:07	5/27/2023 6:14	66	1,971	Newport_ME	X
15		2381245	5/28/2023 1:15	5/28/2023 3:02	106	1,875	Newport_ME	X
16		2382104	5/30/2023 4:34	5/30/2023 5:39	65	815	Faribault_Mankato_SE	X
17		2382314	5/30/2023 8:45	5/30/2023 10:14	88	659	Maple Grove_MW	X
18		2384132	5/31/2023 23:43	6/1/2023 1:20	97	1329	Winona_SE	X
JUNE = 49 total qualifying events, 3 events with no email								
1		2384701	6/1/2023 13:52	6/1/2023 16:12	140	2,617	St Paul_ME	X
2		2386490	6/3/2023 23:35	6/4/2023 1:17	102	1,624	St Paul_ME	X
3		2389053	6/8/2023 0:24	6/8/2023 1:40	75	1,812	Minnetonka_MW	X
4		2390954	6/10/2023 16:10	6/10/2023 20:05	235	1,416	Minnetonka_MW	X
5		2391119	6/10/2023 19:48	6/10/2023 21:07	79	2,187	Maple Grove_MW	X
6		2394091	6/11/2023 2:31	6/11/2023 5:09	158	1,159	Newport_ME	X
7		2392006	6/12/2023 13:19	6/12/2023 15:27	128	621	White Bear_ME	X
8		2393038	6/14/2023 6:58	6/14/2023 8:16	78	2,522	Newport_ME	X
9		2393645	6/14/2023 19:50	6/14/2023 21:02	72	2,868	Minnetonka_MW	X
10		2395149	6/17/2023 14:54	6/17/2023 16:14	80	3,715	St Paul_ME	X
11		2397132	6/20/2023 5:47	6/20/2023 6:48	61	680	Newport_ME	X
12		2397987	6/21/2023 5:56	6/21/2023 7:13	76	2,195	White Bear_ME	X
13		2399122	6/21/2023 20:46	6/21/2023 22:20	93	3,900	Northwest-St Cloud_NT	
14		2400046	6/22/2023 18:11	6/22/2023 20:20	129	1,735	Newport_ME	X

15		2400779	6/23/2023 16:42	6/23/2023 21:44	302	589	Northwest-St Cloud_NT	
16		2400852	6/23/2023 17:23	6/23/2023 19:31	128	1,926	Maple Grove_MW	X
17		2400851	6/23/2023 17:23	6/23/2023 18:56	93	2,516	Maple Grove_MW	X
18		2401425	6/24/2023 11:29	6/24/2023 14:16	167	964	Minnetonka_MW	X
19		2401408	6/24/2023 11:29	6/24/2023 14:16	167	1,409	Minnetonka_MW	X
20		2401417	6/24/2023 11:29	6/24/2023 14:16	167	1,675	Minnetonka_MW	X
21		2401413	6/24/2023 11:29	6/24/2023 15:35	246	1,557	Minnetonka_MW	X
22		2401411	6/24/2023 11:29	6/24/2023 14:16	167	1,749	Minnetonka_MW	X
23		2401416	6/24/2023 11:29	6/24/2023 14:16	167	885	Minnetonka_MW	X
24		2402352	6/24/2023 11:49	6/24/2023 19:03	434	1,308	Maple Grove_MW	X
25		2401794	6/24/2023 11:51	6/24/2023 14:33	162	1,046	Faribault_Mankato_SE	X
26		2401791	6/24/2023 11:51	6/24/2023 13:57	126	1,063	Faribault_Mankato_SE	X
27		2401790	6/24/2023 11:53	6/24/2023 13:11	78	1,447	Mpls_Mtka_Plymouth_MW	X
28		2401869	6/24/2023 12:02	6/24/2023 14:17	134	849	Minnetonka_MW	X
29		2401907	6/24/2023 12:08	6/24/2023 13:51	103	1,175	Mpls_Mtka_Plymouth_MW	X
30		2402263	6/24/2023 12:47	6/24/2023 14:49	121	2,053	Mpls_Mtka_Plymouth_MW	X
31		2402277	6/24/2023 12:50	6/24/2023 14:21	91	1,579	Mpls_Mtka_Plymouth_MW	X
32		2403920	6/24/2023 22:57	6/25/2023 0:01	64	1,623	Minnetonka_MW	X
33		2404148	6/24/2023 23:51	6/25/2023 2:22	151	1,014	St Paul_ME	X
34		2404382	6/25/2023 0:37	6/25/2023 13:06	749	1,043	White Bear_ME	X
35		2404509	6/25/2023 1:31	6/25/2023 5:05	214	964	Minnetonka_MW	X
36		2404504	6/25/2023 1:31	6/25/2023 3:11	100	1,409	Minnetonka_MW	X
37		2404527	6/25/2023 1:31	6/25/2023 3:43	132	1,674	Minnetonka_MW	X
38		2404503	6/25/2023 1:31	6/25/2023 4:46	195	1,557	Minnetonka_MW	X
39		2404502	6/25/2023 1:31	6/25/2023 4:49	198	1,749	Minnetonka_MW	X
40		2404498	6/25/2023 1:31	6/25/2023 5:05	214	885	Minnetonka_MW	X
41		2404511	6/25/2023 1:31	6/25/2023 3:03	92	1,291	Minnetonka_MW	X
42		2404500	6/25/2023 1:31	6/25/2023 3:11	100	1,623	Minnetonka_MW	X
43		2404833	6/25/2023 2:16	6/25/2023 3:34	77	1,276	Maple Grove_MW	X
44		2404974	6/25/2023 6:29	6/25/2023 8:37	128	2,606	Mpls_Mtka_Plymouth_MW	X
45		2405924	6/25/2023 14:38	6/25/2023 15:56	78	1,557	Minnetonka_MW	X
46		2408563	6/28/2023 17:16	6/28/2023 18:35	79	716	Winona_SE	X
47		2409249	6/29/2023 8:53	6/29/2023 10:19	86	5,651	Northwest-St Cloud_NT	X
48		2409365	6/29/2023 14:24	6/29/2023 17:36	192	636	White Bear_ME	
49		2409508	6/29/2023 16:59	6/30/2023 0:48	469	507	Faribault_Mankato_SE	X
	JULY = 64 total qualifying events, 3 events with no email							
1		2431578	7/26/2023 1:44	7/26/2023 4:28	163	1,557	White Bear_ME	X
2		2431633	7/26/2023 1:56	7/26/2023 5:20	203	2,305	Newport_ME	X
3		2414325	7/6/2023 19:08	7/6/2023 21:16	128	1,563	Mpls_Mtka_Plymouth_MW	
4		2422634	7/19/2023 17:16	7/19/2023 18:41	85	1,397	Northwest-St Cloud_NT	X
6		2431525	7/26/2023 1:37	7/26/2023 4:12	155	1,269	St Paul_ME	X
7		2418446	7/13/2023 12:04	7/13/2023 13:45	101	598	Faribault_Mankato_SE	X
8		2435387	7/27/2023 21:31	7/27/2023 22:43	72	718	Winona_SE	X
9		2423260	7/19/2023 18:59	7/20/2023 19:40	1,481	1,546	White Bear_ME	X

10		2423216	7/19/2023 18:57	7/20/2023 20:10	1,513	1,324	White Bear_ME	X
11		2433866	7/24/2023 14:18	7/24/2023 19:23	305	1,324	White Bear_ME	X
12		2418804	7/13/2023 21:07	7/13/2023 22:26	79	1,366	White Bear_ME	X
13		2426835	7/19/2023 18:50	7/20/2023 0:20	330	1,366	White Bear_ME	X
14		2430287	7/24/2023 14:08	7/25/2023 4:29	861	1,366	White Bear_ME	X
15		2427887	7/22/2023 15:55	7/22/2023 17:05	70	2,374	White Bear_ME	X
16		2429199	7/24/2023 14:19	7/24/2023 16:01	101	2,374	White Bear_ME	X
17		2423203	7/19/2023 18:57	7/20/2023 3:45	528	2,401	White Bear_ME	X
18		2429158	7/24/2023 14:08	7/24/2023 17:58	229	1,113	White Bear_ME	X
19		2423130	7/19/2023 18:53	7/20/2023 0:28	335	2,604	White Bear_ME	X
20		2429166	7/24/2023 14:13	7/24/2023 19:07	293	2,604	White Bear_ME	X
21		2429179	7/24/2023 14:15	7/24/2023 17:22	187	774	White Bear_ME	X
22		2423193	7/19/2023 18:56	7/19/2023 22:38	221	2,742	White Bear_ME	X
23		2416826	7/10/2023 20:45	7/10/2023 21:54	68	1,765	Maple Grove_MW	X
24		2422905	7/19/2023 18:25	7/19/2023 20:47	142	1,175	Northwest-St Cloud_NT	X
25		2423103	7/19/2023 18:51	7/20/2023 3:57	545	4,163	White Bear_ME	X
26		2422995	7/19/2023 18:45	7/19/2023 21:51	186	773	White Bear_ME	X
27		2426316	7/14/2023 14:29	7/14/2023 15:30	61	665	White Bear_ME	X
28		2412533	7/4/2023 12:37	7/4/2023 14:12	95	764	White Bear_ME	X
29		2424489	7/19/2023 18:53	7/20/2023 7:23	750	1,162	White Bear_ME	X
30		2431403	7/26/2023 1:29	7/26/2023 3:01	92	2,040	White Bear_ME	X
31		2423046	7/19/2023 18:49	7/19/2023 21:18	149	3,466	White Bear_ME	X
32		2429192	7/24/2023 14:18	7/24/2023 15:51	92	2,006	White Bear_ME	X
33		2422684	7/19/2023 17:49	7/19/2023 19:27	98	1,956	Minnetonka_MW	X
34		2422994	7/19/2023 18:45	7/19/2023 20:12	87	3,088	Mpls_Mtka_Plymouth_MW	X
35		2431336	7/26/2023 1:19	7/26/2023 2:50	91	1,381	St Paul_ME	X
36		2416966	7/11/2023 0:28	7/11/2023 2:20	112	1,975	Northwest-St Cloud_NT	X
37		2432052	7/26/2023 6:23	7/26/2023 8:49	145	1,235	Faribault_Mankato_SE	X
38		2414092	7/4/2023 12:24	7/4/2023 17:57	333	2,320	White Bear_ME	X
39		2431175	7/25/2023 23:33	7/26/2023 2:34	181	2,592	Northwest-St Cloud_NT	X
40		2431168	7/25/2023 23:29	7/26/2023 12:03	753	559	Northwest-St Cloud_NT	X
41		2412277	7/4/2023 10:45	7/4/2023 18:24	459	2,252	White Bear_ME	X
42		2422635	7/19/2023 17:16	7/19/2023 18:41	85	791	Northwest-St Cloud_NT	X
43		2437461	7/29/2023 1:04	7/29/2023 2:21	77	2,129	Winona_SE	X
44		2436919	7/28/2023 18:02	7/28/2023 19:40	97	2,129	Winona_SE	X
45		2412623	7/4/2023 13:24	7/4/2023 15:06	102	862	St Paul_ME	X
46		2422637	7/19/2023 17:16	7/19/2023 18:41	85	757	Northwest-St Cloud_NT	X
47		2431805	7/26/2023 5:18	7/26/2023 6:37	79	1,093	White Bear_ME	X
48		2429409	7/24/2023 15:37	7/24/2023 17:27	109	1,550	Northwest-St Cloud_NT	X
49		2427373	7/21/2023 23:46	7/22/2023 11:43	716	1,504	St Paul_ME	X
50		2435586	7/28/2023 0:11	7/28/2023 14:14	843	1,711	Faribault_Mankato_SE	X
51		2435581	7/28/2023 0:16	7/28/2023 3:50	214	1,622	Faribault_Mankato_SE	X
52		2436634	7/28/2023 16:56	7/28/2023 18:32	96	1,075	Edina_MW	X
53		2428222	7/22/2023 22:44	7/23/2023 0:21	97	1,532	Faribault_Mankato_SE	X

54		2435667	7/28/2023 0:53	7/28/2023 3:23	150	933	Faribault_Mankato_SE	X
55		2435138	7/27/2023 19:59	7/27/2023 21:09	70	2,870	St Paul_ME	X
56		2422938	7/19/2023 18:38	7/19/2023 19:40	62	2,518	Maple Grove_MW	X
57		2415160	7/8/2023 0:37	7/8/2023 3:56	199	2,554	Maple Grove_MW	X
58		2438350	7/30/2023 11:23	7/30/2023 12:38	75	1,978	St Paul_ME	
59		2438348	7/30/2023 11:23	7/30/2023 12:38	75	1,013	St Paul_ME	
60		2422925	7/19/2023 18:34	7/19/2023 20:17	102	2,452	White Bear_ME	X
61		2421379	7/17/2023 17:30	7/17/2023 18:59	88	3,236	Northwest-St Cloud_NT	X
62		2422684	7/19/2023 17:49	7/19/2023 19:27	98	1,956	Minnetonka_MW	X
63		2429409	7/24/2023 15:37	7/24/2023 17:27	109	1,550	Northwest-St Cloud_NT	X
64		2438350	7/30/2023 11:23	7/30/2023 12:38	75	1,978	Metro East	X
AUGUST = 32 total qualifying events, 1 event with no email								
1		2440549	8/2/2023 17:04	8/2/2023 18:28	84	2,028	White Bear_ME	X
2		2440806	8/2/2023 19:29	8/3/2023 4:50	561	1118	Mpls_Mtka_Plymouth_MW	X
3		2444318	8/7/2023 10:17	8/7/2023 11:44	86	842	White Bear_ME	X
4		2446362	8/10/2023 12:15	8/10/2023 14:43	148	4,162	White Bear_ME	X
5		2446363	8/10/2023 12:15	8/10/2023 14:50	155	3,965	White Bear_ME	X
6		2446959	8/11/2023 0:51	8/11/2023 4:09	197	1,180	Northwest-St Cloud_NT	X
7		2447031	8/11/2023 5:21	8/11/2023 6:51	90	686	Maple Grove_MW	X
8		2447474	8/11/2023 14:53	8/11/2023 16:19	86	2,820	White Bear_ME	X
9		2448094	8/11/2023 17:37	8/11/2023 19:04	87	2,999	St Paul_ME	X
10		2448100	8/11/2023 17:37	8/11/2023 19:04	24	2,807	St Paul_ME	X
11		2448105	8/11/2023 17:37	8/11/2023 19:04	24	2,702	St Paul_ME	X
12		2448128	8/11/2023 17:37	8/11/2023 19:04	24	1,976	St Paul_ME	X
13		2448247	8/11/2023 17:37	8/11/2023 19:04	24	1,923	St Paul_ME	X
14		2448101	8/11/2023 17:37	8/11/2023 19:04	24	319	St Paul_ME	X
15		2448130	8/11/2023 17:37	8/11/2023 19:04	24	1,268	St Paul_ME	X
16		2448163	8/11/2023 17:37	8/11/2023 19:04	24	593	St Paul_ME	X
17		2448103	8/11/2023 17:37	8/11/2023 19:04	24	411	St Paul_ME	X
18		2448345	8/11/2023 17:37	8/11/2023 19:04	24	206	St Paul_ME	X
19		2449417	8/12/2023 11:51	8/12/2023 13:00	68	3,663	St Paul_ME	X
20		2450863	8/14/2023 15:59	8/14/2023 17:13	73	579	Newport_ME	X
21		2450920	8/14/2023 15:59	8/14/2023 18:22	142	1265	Newport_ME	X
22		2451063	8/14/2023 20:39	8/14/2023 22:21	101	830	St Paul_ME	X
23		2454714	8/19/2023 17:54	8/19/2023 19:14	80	1001	Edina_MW	X
24		2457556	8/23/2023 20:58	8/23/2023 22:33	94	2,205	White Bear_ME	X
25		2460534	8/29/2023 12:49	8/29/2023 14:10	81	1,856	St Paul_ME	X
26		2460572	8/29/2023 12:49	8/29/2023 14:10	81	1,242	St Paul_ME	
27		2440902	8/2/2023 20:04	8/3/2023 0:11	246	2,475	Metro West	X
28		2442918	8/5/2023 17:29	8/6/2023 0:12	402	1,454	Metro East	X
29		2447480	8/11/2023 14:53	8/11/2023 15:45	52	1,063	Metro East	X
30		2452788	8/16/2023 16:03	8/16/2023 18:04	643	935	Metro West	X
31		2456652	8/22/2023 21:46	8/22/2023 23:58	131	792	Metro East	X
32		2456723	8/23/2023 5:21	8/23/2023 17:43	60	3,146	Metro East	X
SEPTEMBER = 21 total qualifying events, 1 event with no email								
1		2463219	9/3/2023 15:43	9/3/2023 17:11	88	2,356	White Bear_ME	X
2		2463222	9/3/2023 15:45	9/3/2023 17:22	97	2,056	Newport_ME	X
3		2463475	9/3/2023 19:59	9/3/2023 22:06	127	3,337	Northwest-St Cloud_NT	X

4		2467343	9/10/2023 6:52	9/10/2023 8:27	95	920	Mpls_Mtka_Plymouth_MW	X
5		2467883	9/10/2023 8:49	9/10/2023 10:08	79	1,247	Faribault_Mankato_SE	X
6		2467891	9/10/2023 8:49	9/10/2023 10:08	79	1,804	Faribault_Mankato_SE	X
7		2467888	9/10/2023 8:49	9/10/2023 10:08	79	1	Faribault_Mankato_SE	X
8		2470002	9/15/2023 14:12	9/15/2023 15:31	79	526	Newport_ME	
9		2471935	9/20/2023 12:16	9/20/2023 23:42	685	1,066	White Bear_ME	X
10		2472033	9/20/2023 15:47	9/20/2023 17:12	84	761	White Bear_ME	X
11		2473200	9/23/2023 6:00	9/23/2023 7:10	69	1,647	Faribault_Mankato_SE	X
12		2473491	9/23/2023 17:17	9/23/2023 19:08	111	3,864	Mpls_Mtka_Plymouth_MW	X
13		2473707	9/23/2023 23:46	9/24/2023 2:49	183	870	Northwest-St Cloud_NT	X
14		2473748	9/26/2023 0:35	9/26/2023 3:04	148	707	Maple Grove_MW	X
15		2475129	9/26/2023 5:20	9/26/2023 7:15	115	977	Newport_ME	X
16		2475249	9/29/2023 8:44	9/29/2023 9:49	65	1,250	Mpls_Mtka_Plymouth_MW	X
17		2475219	9/26/2023 5:20	9/29/2023 9:49	115	137	Mpls_Mtka_Plymouth_MW	X
18		2477215	9/29/2023 21:04	9/29/2023 23:40	156	2,254	St Paul_ME	X
19		2478166	9/29/2023 22:45	9/30/2023 1:00	135	2,173	Maple Grove_MW	X
20		2478258	9/30/2023 12:27	9/30/2023 14:20	112	948	Minnetonka_MW	X
21		2479403	9/30/2023 12:27	9/30/2023 12:27	101	3195	Minnetonka_MW	X
	OCTOBER = 14 total qualifying events, 0 events with no email							
1		2482906	10/5/2023 8:00	10/5/2023 10:00	120	1,313	Northwest-St Cloud_NT	X
2		2481628	10/4/2023 0:12	10/4/2023 1:39	86	3,057	St Paul_ME	X
3		2481627	10/4/2023 0:12	10/4/2023 2:27	135	637	St Paul_ME	X
4		2484367	10/7/2023 16:18	10/7/2023 23:40	442	975	Edina_MW	X
5		2481319	10/3/2023 17:56	10/3/2023 19:00	64	1,028	Northwest-St Cloud_NT	X
6		2481684	10/4/2023 0:24	10/4/2023 1:25	60	664	White Bear_ME	X
7		2481425	10/3/2023 18:19	10/3/2023 19:36	77	1211	Minnetonka_MW	X
8		2487691	10/13/2023 11:58	10/13/2023 13:21	83	1,370	Mpls_Mtka_Plymouth_MW	X
9		2481658	10/4/2023 0:20	10/4/2023 1:32	71	1,243	Mpls_Mtka_Plymouth_MW	X
10		2481311	10/3/2023 17:56	10/3/2023 19:00	64	1,986	Northwest-St Cloud_NT	X
11		2485264	10/9/2023 19:55	10/10/2023 0:32	277	1,987	Newport_ME	X
12		2481313	10/3/2023 17:56	10/3/2023 19:00	64	1,277	Northwest-St Cloud_NT	X
13		2483619	10/6/2023 6:54	10/6/2023 8:45	111	3164	Minnetonka_MW	X
14		2487227	10/13/2023 4:15	10/13/2023 11:30	247	1015	Metro East	X
	NOVEMBER = 4 total qualifying events, 0 events with no email							
1		2501062	11/13/2023 8:41	11/13/2023 10:00	79	1344	St Paul_ME	X
2		2501572	11/14/2023 11:22	11/14/2023 14:25	183	2377	St Paul_ME	X
3		2506396	11/26/2023 13:56	11/26/2023 15:55	118	1493	Metro West	X
4		2507185	11/28/2023 10:31	11/28/2023 11:00	29	1099	Metro West	X
	DECEMBER = 7 total qualifying events, 0 events with no email							
1		2513882	12/18/2023 2:58	12/18/2023 4:37	99	770	Edina_MW	x
2		2513956	12/18/2023 4:26	12/18/2023 7:27	182	1,983	White Bear_ME	x
3		2514862	12/20/2023 14:28	12/20/2023 15:43	75	801	Northwest-St Cloud_NT	x

4		2514992	12/20/2023 15:16	12/20/2023 16:44	88	2,249	St Paul_ME	x
5		2516063	12/24/2023 16:21	12/24/2023 17:23	62	1,341	St Paul_ME	x
6		2516334	12/25/2023 13:17	12/25/2023 15:01	103	1,270	White Bear_ME	x
7		2513253	12/15/2023 22:29	12/16/2023 2:20	230	1,721	Metro East	x

...PROTECTED DATA ENDS]

Minnesota - MAIFI		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	0.02	0.04	0.03	0.14	0.05	0.07	0.09	0.07	0.08	0.05	0.03	0.03	0.69
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.03	0.02	0.08	0.04	0.04	0.07	0.06	0.06	0.05	0.03	0.03	0.53
	Annual Normalized, IEEE Region All Levels, All Cau	0.02	0.04	0.03	0.11	0.05	0.06	0.07	0.07	0.08	0.05	0.03	0.03	0.63
2022	With Storms, All Levels, All Causes	0.03	0.02	0.03	0.07	0.18	0.12	0.07	0.08	0.04	0.05	0.05	0.03	0.76
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.02	0.02	0.05	0.10	0.11	0.07	0.05	0.03	0.05	0.04	0.03	0.57
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.02	0.03	0.07	0.10	0.12	0.07	0.05	0.04	0.05	0.05	0.03	0.65
2021	With Storms, All Levels, All Causes	0.02	0.03	0.04	0.06	0.06	0.11	0.08	0.11	0.10	0.05	0.03	0.05	0.72
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.03	0.04	0.05	0.06	0.11	0.06	0.09	0.06	0.04	0.03	0.03	0.60
	Annual Normalized, IEEE Region All Levels, All Cau	0.02	0.03	0.04	0.06	0.06	0.11	0.08	0.09	0.08	0.05	0.03	0.04	0.69
2020	With Storms, All Levels, All Causes	0.01	0.03	0.03	0.06	0.07	0.17	0.12	0.15	0.07	0.07	0.03	0.06	0.88
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.03	0.03	0.04	0.07	0.15	0.09	0.10	0.06	0.06	0.02	0.05	0.70
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.03	0.03	0.06	0.07	0.17	0.11	0.11	0.07	0.06	0.03	0.06	0.82
2019	With Storms, All Levels, All Causes	0.03	0.04	0.06	0.11	0.09	0.08	0.10	0.06	0.14	0.06	0.04	0.01	0.82
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.01	0.06	0.07	0.07	0.06	0.07	0.05	0.09	0.06	0.02	0.01	0.60
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.04	0.06	0.08	0.09	0.08	0.09	0.06	0.12	0.06	0.04	0.01	0.77

MAIFI - <= 5 Minutes Duration

Metro East - MAIFI		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	0.04	0.05	0.03	0.09	0.04	0.03	0.11	0.06	0.05	0.05	0.02	0.04	0.60
	Tariff Normalized, IEEE Region No Trans Line, All C	0.03	0.04	0.03	0.01	0.03	0.03	0.07	0.06	0.05	0.04	0.02	0.04	0.45
	Annual Normalized, IEEE Region All Levels, All Cau	0.04	0.05	0.03	0.01	0.04	0.03	0.07	0.06	0.05	0.05	0.02	0.04	0.49
2022	With Storms, All Levels, All Causes	0.05	0.01	0.02	0.09	0.16	0.16	0.09	0.08	0.03	0.04	0.05	0.04	0.82
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.01	0.02	0.06	0.06	0.16	0.09	0.04	0.03	0.04	0.05	0.02	0.61
	Annual Normalized, IEEE Region All Levels, All Cau	0.05	0.01	0.02	0.09	0.06	0.16	0.09	0.04	0.03	0.04	0.05	0.02	0.67
2021	With Storms, All Levels, All Causes	0.01	0.04	0.05	0.06	0.11	0.11	0.05	0.07	0.08	0.05	0.05	0.07	0.77
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.04	0.05	0.05	0.11	0.11	0.05	0.05	0.06	0.05	0.05	0.04	0.69
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.04	0.05	0.06	0.11	0.11	0.05	0.05	0.06	0.05	0.05	0.07	0.73
2020	With Storms, All Levels, All Causes	0.00	0.05	0.05	0.08	0.07	0.20	0.15	0.15	0.05	0.05	0.02	0.09	0.97
	Tariff Normalized, IEEE Region No Trans Line, All C	0.00	0.05	0.05	0.08	0.07	0.18	0.12	0.10	0.04	0.05	0.02	0.08	0.85
	Annual Normalized, IEEE Region All Levels, All Cau	0.00	0.05	0.05	0.08	0.07	0.20	0.15	0.13	0.05	0.05	0.02	0.09	0.95
2019	With Storms, All Levels, All Causes	0.03	0.08	0.05	0.09	0.06	0.04	0.11	0.07	0.10	0.06	0.04	0.00	0.74
	Tariff Normalized, IEEE Region No Trans Line, All C	0.03	0.01	0.05	0.09	0.06	0.03	0.06	0.07	0.05	0.06	0.03	0.00	0.54
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.08	0.05	0.09	0.06	0.04	0.09	0.07	0.08	0.06	0.04	0.00	0.70

MAIFI - <= 5 Minutes Duration

Metro West - MAIFI		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	0.01	0.03	0.02	0.16	0.06	0.06	0.05	0.07	0.06	0.05	0.03	0.02	0.62
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.03	0.01	0.14	0.06	0.02	0.05	0.06	0.06	0.05	0.03	0.02	0.55
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.03	0.01	0.15	0.06	0.03	0.05	0.07	0.06	0.05	0.03	0.02	0.57
2022	With Storms, All Levels, All Causes	0.01	0.02	0.04	0.06	0.18	0.07	0.07	0.09	0.06	0.06	0.03	0.02	0.70
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.02	0.02	0.05	0.12	0.07	0.07	0.05	0.04	0.06	0.03	0.02	0.56
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.02	0.04	0.06	0.12	0.07	0.07	0.05	0.06	0.06	0.03	0.02	0.60
2021	With Storms, All Levels, All Causes	0.03	0.02	0.02	0.05	0.03	0.07	0.05	0.11	0.08	0.04	0.01	0.03	0.53
	Tariff Normalized, IEEE Region No Trans Line, All C	0.03	0.02	0.02	0.05	0.03	0.07	0.05	0.10	0.06	0.04	0.01	0.03	0.50
		0.03	0.02	0.02	0.05	0.03	0.07	0.05	0.10	0.07	0.04	0.01	0.03	0.51
2020	With Storms, All Levels, All Causes	0.01	0.01	0.02	0.02	0.07	0.15	0.09	0.12	0.08	0.08	0.03	0.04	0.72
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.01	0.02	0.02	0.07	0.15	0.06	0.06	0.08	0.08	0.03	0.04	0.62
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.01	0.02	0.02	0.07	0.15	0.09	0.06	0.08	0.06	0.03	0.04	0.63
2019	With Storms, All Levels, All Causes	0.02	0.01	0.05	0.08	0.08	0.09	0.07	0.04	0.11	0.07	0.02	0.02	0.64
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.00	0.05	0.08	0.08	0.09	0.06	0.04	0.11	0.07	0.01	0.02	0.61
	Annual Normalized, IEEE Region All Levels, All Cau	0.02	0.01	0.05	0.08	0.08	0.09	0.06	0.04	0.11	0.07	0.02	0.02	0.64

MAIFI - <= 5 Minutes Duration

Northwest - MAIFI		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	0.02	0.02	0.10	0.25	0.03	0.21	0.20	0.12	0.23	0.05	0.04	0.01	1.27
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.02	0.10	0.08	0.02	0.18	0.12	0.09	0.14	0.05	0.04	0.01	0.86
	Annual Normalized, IEEE Region All Levels, All Cau	0.02	0.02	0.10	0.25	0.03	0.21	0.17	0.12	0.23	0.05	0.04	0.01	1.25
2022	With Storms, All Levels, All Causes	0.01	0.03	0.01	0.02	0.27	0.15	0.01	0.06	0.03	0.09	0.09	0.07	0.85
	Tariff Normalized, IEEE Region No Trans Line, All C	0.00	0.03	0.01	0.02	0.18	0.11	0.01	0.06	0.00	0.06	0.07	0.07	0.62
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.03	0.01	0.02	0.20	0.13	0.01	0.06	0.03	0.09	0.09	0.07	0.76
2021	With Storms, All Levels, All Causes	0.00	0.02	0.10	0.19	0.05	0.34	0.21	0.22	0.13	0.09	0.00	0.06	1.41
	Tariff Normalized, IEEE Region No Trans Line, All C	0.00	0.02	0.10	0.10	0.05	0.27	0.15	0.14	0.03	0.04	0.00	0.05	0.95
	Annual Normalized, IEEE Region All Levels, All Cau	0.00	0.02	0.10	0.19	0.05	0.34	0.21	0.18	0.13	0.09	0.00	0.06	1.37
2020	With Storms, All Levels, All Causes	0.01	0.10	0.06	0.10	0.16	0.20	0.14	0.23	0.07	0.13	0.01	0.06	1.27
	Tariff Normalized, IEEE Region No Trans Line, All C	0.01	0.10	0.02	0.04	0.13	0.13	0.08	0.18	0.01	0.05	0.01	0.00	0.75
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.10	0.06	0.10	0.16	0.20	0.09	0.23	0.07	0.13	0.01	0.06	1.22
2019	With Storms, All Levels, All Causes	0.01	0.05	0.12	0.09	0.17	0.14	0.17	0.16	0.46	0.04	0.08	0.05	1.52
	Tariff Normalized, IEEE Region No Trans Line, All C	0.00	0.03	0.12	0.03	0.09	0.09	0.13	0.05	0.16	0.04	0.06	0.05	0.84
	Annual Normalized, IEEE Region All Levels, All Cau	0.01	0.05	0.12	0.06	0.17	0.14	0.17	0.16	0.40	0.04	0.08	0.05	1.43

MAIFI - <= 5 Minutes Duration

Southeast - MAIFI		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	0.03	0.04	0.03	0.13	0.06	0.11	0.06	0.06	0.16	0.04	0.05	0.04	0.79
	Tariff Normalized, IEEE Region No Trans Line, All C	0.00	0.00	0.01	0.02	0.05	0.04	0.04	0.06	0.03	0.04	0.04	0.03	0.36
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.04	0.03	0.13	0.06	0.11	0.04	0.06	0.16	0.04	0.05	0.04	0.78
2022	With Storms, All Levels, All Causes	0.05	0.00	0.03	0.08	0.12	0.19	0.10	0.07	0.02	0.03	0.07	0.02	0.78
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.00	0.00	0.03	0.05	0.12	0.05	0.06	0.02	0.03	0.02	0.02	0.42
	Annual Normalized, IEEE Region All Levels, All Cau	0.05	0.00	0.03	0.08	0.08	0.19	0.10	0.07	0.02	0.03	0.07	0.02	0.74
2021	With Storms, All Levels, All Causes	0.03	0.09	0.04	0.01	0.01	0.09	0.14	0.11	0.21	0.04	0.02	0.04	0.83
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.08	0.01	0.01	0.01	0.09	0.07	0.09	0.09	0.03	0.02	0.00	0.52
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.09	0.04	0.01	0.01	0.09	0.14	0.11	0.21	0.04	0.02	0.00	0.79
2020	With Storms, All Levels, All Causes	0.03	0.00	0.00	0.14	0.01	0.15	0.14	0.22	0.08	0.05	0.09	0.03	0.96
	Tariff Normalized, IEEE Region No Trans Line, All C	0.03	0.00	0.00	0.04	0.01	0.10	0.11	0.15	0.07	0.04	0.02	0.00	0.56
	Annual Normalized, IEEE Region All Levels, All Cau	0.03	0.00	0.00	0.14	0.01	0.15	0.14	0.17	0.08	0.05	0.09	0.03	0.90
2019	With Storms, All Levels, All Causes	0.04	0.04	0.13	0.30	0.11	0.15	0.14	0.03	0.12	0.05	0.09	0.02	1.22
	Tariff Normalized, IEEE Region No Trans Line, All C	0.02	0.04	0.09	0.02	0.04	0.03	0.08	0.03	0.04	0.05	0.05	0.01	0.48
	Annual Normalized, IEEE Region All Levels, All Cau	0.04	0.04	0.13	0.12	0.11	0.15	0.12	0.03	0.09	0.05	0.09	0.02	0.99

MAIFI - <= 5 Minutes Duration

Minnesota - Customer Interruptions		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	26,994	51,613	45,416	188,937	65,423	90,955	116,105	92,784	106,510	66,333	42,505	36,526	930,101
	Tariff Normalized, IEEE Region No Trans Line, All C	17,355	42,507	33,122	108,202	58,131	55,499	87,308	86,138	77,770	63,478	41,901	35,267	706,678
	Annual Normalized, IEEE Region All Levels, All Cau	26,994	51,613	35,244	148,506	65,423	75,681	94,794	92,784	106,510	66,333	42,505	36,526	842,913
	CES Cust Served	1,335,873	1,337,466	1,336,133	1,337,430	1,338,535	1,335,607	1,340,270	1,341,849	1,343,816	1,348,124	1,350,046	1,351,959	
2022	With Storms, All Levels, All Causes	35,895	21,428	36,985	88,710	235,216	159,774	97,051	108,797	56,247	67,723	62,104	44,075	1,014,005
	Tariff Normalized, IEEE Region No Trans Line, All C	19,960	21,428	23,016	68,229	130,379	145,521	90,719	67,038	41,482	63,845	51,370	34,045	757,032
	Annual Normalized, IEEE Region All Levels, All Cau	35,895	21,428	36,985	88,710	137,974	157,110	97,051	68,474	56,247	67,723	62,104	34,045	863,746
	CES Cust Served	1,324,119	1,325,254	1,327,088	1,328,088	1,327,967	1,327,652	1,327,732	1,328,421	1,329,048	1,330,817	1,332,272	1,334,479	
2021	With Storms, All Levels, All Causes	24,324	43,648	49,795	79,383	74,122	145,866	101,017	138,048	130,570	65,673	33,770	60,947	947,163
	Tariff Normalized, IEEE Region No Trans Line, All C	22,911	38,520	46,020	62,452	74,122	137,934	85,098	114,698	74,756	58,274	33,769	42,198	790,752
	Annual Normalized, IEEE Region All Levels, All Cau	24,324	43,648	49,795	79,383	74,122	145,866	101,017	122,217	111,392	65,673	33,770	55,599	906,806
	CES Cust Served	1,301,933	1,304,654	1,307,442	1,308,019	1,308,083	1,309,157	1,310,749	1,313,826	1,315,994	1,318,851	1,321,135	1,322,302	
2020	With Storms, All Levels, All Causes	10,396	39,042	39,986	75,276	94,115	222,654	157,725	197,967	93,098	93,900	35,448	76,966	1,136,573
	Tariff Normalized, IEEE Region No Trans Line, All C	10,396	39,042	35,813	54,924	88,609	197,434	113,516	123,612	81,003	79,725	25,943	61,441	911,458
	Annual Normalized, IEEE Region All Levels, All Cau	10,396	39,042	39,986	75,276	94,115	222,654	147,286	144,530	93,098	80,913	35,448	76,966	1,059,710
	CES Cust Served	1,290,479	1,293,848	1,294,877	1,295,113	1,295,757	1,296,076	1,296,089	1,296,619	1,297,076	1,297,132	1,298,128	1,299,397	
2019	With Storms, All Levels, All Causes	33,812	52,508	81,258	134,469	108,928	103,049	124,083	79,369	179,825	75,041	50,310	18,447	1,041,099
	Tariff Normalized, IEEE Region No Trans Line, All C	28,787	16,119	76,448	87,955	88,939	80,372	87,100	65,265	110,861	75,041	30,296	16,859	764,042
	Annual Normalized, IEEE Region All Levels, All Cau	33,812	52,508	81,258	107,764	108,928	103,049	111,694	79,369	159,811	75,041	50,310	18,447	981,991
	CES Cust Served	1,271,572	1,272,182	1,273,191	1,273,389	1,273,236	1,272,910	1,273,366	1,280,040	1,280,959	1,282,278	1,284,381	1,287,572	

Metro East - Customer Interruptions	January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023 With Storms, All Levels, All Causes	16,734	23,180	15,131	38,270	17,142	13,549	49,537	26,243	20,447	21,084	10,064	15,874	267,255
Tariff Normalized, IEEE Region No Trans Line, All C	11,263	18,905	15,131	3,811	12,965	13,549	32,786	26,243	20,447	18,500	10,064	15,874	199,538
Annual Normalized, IEEE Region All Levels, All Cau	16,734	23,180	15,131	3,811	17,142	13,549	32,786	26,243	20,447	21,084	10,064	15,874	216,045
CES Cust Served	441,761	442,240	442,532	442,883	443,424	443,639	443,861	444,176	444,588	444,987	445,619	446,451	
2022 With Storms, All Levels, All Causes	20,394	5,961	8,862	40,773	69,282	70,487	39,289	34,591	13,700	16,134	23,729	17,873	361,075
Tariff Normalized, IEEE Region No Trans Line, All C	9,909	5,961	8,862	26,702	26,745	70,487	39,289	17,990	13,700	16,133	23,729	7,843	267,350
Annual Normalized, IEEE Region All Levels, All Cau	20,394	5,961	8,862	40,773	26,986	70,487	39,289	17,990	13,700	16,134	23,729	7,843	292,148
CES Cust Served	437,017	437,393	438,274	438,661	438,831	438,877	438,923	439,239	439,660	440,084	440,685	441,360	
2021 With Storms, All Levels, All Causes	3,058	16,639	22,450	25,223	48,489	49,219	23,752	29,321	36,864	22,706	23,137	31,059	331,917
Tariff Normalized, IEEE Region No Trans Line, All C	3,058	16,639	22,450	19,493	48,489	49,218	23,752	23,021	24,986	22,706	23,136	19,286	296,234
Annual Normalized, IEEE Region All Levels, All Cau	3,058	16,639	22,450	25,223	48,489	49,219	23,752	23,021	24,986	22,706	23,137	31,059	313,739
CES Cust Served	428,444	429,234	430,346	430,527	430,677	431,454	432,101	433,066	433,949	435,194	435,923	436,222	
2020 With Storms, All Levels, All Causes		21,232	22,795	34,095	31,423	87,285	63,157	64,341	22,355	22,675	6,522	37,749	413,629
Tariff Normalized, IEEE Region No Trans Line, All Causes		21,232	22,795	34,095	31,183	78,150	53,017	44,777	18,391	19,787	6,522	34,516	364,465
Annual Normalized, IEEE Region All Levels, All Causes		21,232	22,795	34,095	31,423	87,285	63,157	54,908	22,355	22,675	6,522	37,749	404,196
CES Cust Served	424,660	426,282	426,613	426,479	426,652	426,708	426,462	426,801	426,834	426,885	427,232	427,721	
2019 With Storms, All Levels, All Causes	13,545	35,223	19,335	39,427	25,017	15,108	45,934	31,388	43,475	23,817	18,352	2	310,623
Tariff Normalized, IEEE Region No Trans Line, All C	13,545	4,999	19,335	35,822	25,017	13,692	25,945	31,388	22,336	23,817	11,675	2	227,573
Annual Normalized, IEEE Region All Levels, All Cau	13,545	35,223	19,335	39,427	25,017	15,108	39,627	31,388	35,312	23,817	18,352	2	296,153
CES Cust Served	419,683	419,901	420,157	420,211	420,088	419,961	420,135	421,742	421,918	422,298	423,044	424,150	

Metro West - Customer Interruptions	January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023 With Storms, All Levels, All Causes	3,735	21,158	14,303	102,243	35,852	36,163	34,176	42,810	35,619	33,000	20,618	14,689	394,366
Tariff Normalized, IEEE Region No Trans Line, All C	3,735	21,158	4,131	91,847	35,852	13,201	34,176	41,152	35,619	33,000	20,618	14,689	349,178
Annual Normalized, IEEE Region All Levels, All Cau	3,735	21,158	4,131	96,271	35,852	20,889	34,176	42,810	35,619	33,000	20,618	14,689	362,948
CES Cust Served	633,648	634,388	632,669	633,517	633,938	630,668	635,158	635,999	637,405	640,893	641,989	642,604	
2022 With Storms, All Levels, All Causes	7,448	11,767	22,607	34,796	115,548	45,106	43,212	57,233	35,763	36,294	17,880	14,569	442,223
Tariff Normalized, IEEE Region No Trans Line, All C	7,279	11,767	12,575	34,627	74,938	45,106	43,212	33,511	25,722	36,294	15,922	14,569	355,522
Annual Normalized, IEEE Region All Levels, All Cau	7,448	11,767	22,607	34,796	74,938	45,106	43,212	33,511	35,763	36,294	17,880	14,569	377,891
CES Cust Served	628,724	629,209	629,883	630,342	630,198	629,915	629,739	629,790	629,983	630,923	631,560	632,808	
2021 With Storms, All Levels, All Causes	17,511	12,411	10,111	29,718	18,187	42,356	32,865	67,209	48,752	27,008	7,784	16,805	330,717
Tariff Normalized, IEEE Region No Trans Line, All C	17,511	9,549	10,111	29,718	18,187	42,356	32,865	62,194	34,821	27,008	7,784	16,805	308,909
Annual Normalized, IEEE Region All Levels, All Cau	17,511	12,411	10,111	29,718	18,187	42,356	32,865	62,194	41,452	27,008	7,784	16,805	318,402
CES Cust Served	618,963	620,426	621,339	621,741	621,752	621,901	622,483	624,083	625,023	626,431	627,511	628,040	
2020 With Storms, All Levels, All Causes	5,461	5,585	10,064	10,976	41,059	90,801	58,284	76,417	51,502	48,884	16,127	26,842	442,002
Tariff Normalized, IEEE Region No Trans Line, All C	5,461	5,585	10,064	10,976	41,059	90,801	36,345	38,039	51,502	48,884	16,127	26,842	381,685
Annual Normalized, IEEE Region All Levels, All Cau	5,461	5,585	10,064	10,976	41,059	90,801	53,880	39,950	51,502	35,897	16,127	26,842	388,144
CES Cust Served	613,516	614,496	614,923	615,283	616,090	616,224	616,529	616,512	616,878	616,744	617,202	617,724	
2019 With Storms, All Levels, All Causes	12,910	6,452	31,818	46,135	48,620	52,224	39,878	24,462	64,468	40,849	11,121	10,557	389,494
Tariff Normalized, IEEE Region No Trans Line, All C	12,687	2,015	31,818	46,135	47,497	52,224	34,914	23,340	64,468	40,849	5,698	10,557	372,202
Annual Normalized, IEEE Region All Levels, All Cau	12,910	6,452	31,818	46,135	48,620	52,224	36,037	24,462	64,468	40,849	11,121	10,557	385,653
CES Cust Served	602,621	602,845	603,436	603,556	603,725	603,657	603,795	608,316	608,874	609,255	610,028	611,784	

Northwest - Customer Interruptions		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	2,331	2,444	12,205	31,409	3,919	27,080	24,908	15,906	29,096	6,643	5,642	828	162,411
	Tariff Normalized, IEEE Region No Trans Line, All C	2,331	2,444	12,205	10,257	2,624	23,387	14,695	10,918	17,676	6,643	5,642	828	109,650
	Annual Normalized, IEEE Region All Levels, All Cau	2,331	2,444	12,205	31,409	3,919	27,080	22,181	15,906	29,096	6,643	5,642	828	159,684
	CES Cust Served	126,994	127,252	127,344	127,405	127,588	127,671	127,666	127,872	128,015	128,321	128,457	128,792	
2022	With Storms, All Levels, All Causes	1,305	3,221	1,624	2,751	34,572	19,535	1,064	7,401	4,257	11,397	10,966	9,344	107,437
	Tariff Normalized, IEEE Region No Trans Line, All Causes		3,221	1,579	2,751	22,265	14,205	1,063	7,401	10	7,520	9,340	9,344	78,699
	Annual Normalized, IEEE Region All Levels, All Cau	1,305	3,221	1,624	2,751	25,255	16,871	1,064	7,401	4,257	11,397	10,966	9,344	95,456
	CES Cust Served	125,757	125,950	126,136	126,186	126,178	126,149	126,241	126,382	126,385	126,558	126,667	126,845	
2021	With Storms, All Levels, All Causes		2,199	12,577	23,294	6,108	41,911	26,417	26,930	16,733	11,005	15	7,732	174,921
	Tariff Normalized, IEEE Region No Trans Line, All Causes		2,199	11,929	12,093	6,108	34,014	18,738	17,655	3,538	5,218	15	6,104	117,611
	Annual Normalized, IEEE Region All Levels, All Causes		2,199	12,577	23,294	6,108	41,911	26,417	22,414	16,733	11,005	15	7,732	170,405
	CES Cust Served	123,499	123,748	124,141	124,109	124,144	124,193	124,395	124,592	124,797	124,938	125,330	125,526	
2020	With Storms, All Levels, All Causes	885	12,198	6,920	11,708	19,925	24,671	17,486	27,932	8,402	16,134	1,298	7,967	155,526
	Tariff Normalized, IEEE Region No Trans Line, All C	885	12,198	2,748	4,362	15,613	15,912	9,343	21,861	1,485	6,257	1,298	27	91,989
	Annual Normalized, IEEE Region All Levels, All Cau	885	12,198	6,920	11,708	19,925	24,671	11,451	27,932	8,402	16,134	1,298	7,967	149,491
	CES Cust Served	122,214	122,579	122,794	122,821	122,682	122,715	122,721	122,854	122,872	122,971	123,052	123,224	
2019	With Storms, All Levels, All Causes	1,728	5,899	13,998	10,907	20,768	16,473	20,235	19,306	56,047	4,285	9,243	5,554	184,443
	Tariff Normalized, IEEE Region No Trans Line, All Causes		4,172	13,998	3,710	11,114	11,089	15,677	6,357	19,484	4,285	6,821	5,554	102,261
	Annual Normalized, IEEE Region All Levels, All Cau	1,728	5,899	13,998	6,769	20,768	16,473	20,235	19,306	48,244	4,285	9,243	5,554	172,502
	CES Cust Served	120,666	120,755	120,871	120,858	120,786	120,697	120,884	121,043	121,183	121,384	121,716	121,815	

Southeast - Customer Interruptions		January	February	March	April	May	June	July	August	September	October	November	December	YTD
2023	With Storms, All Levels, All Causes	4,194	4,831	3,777	17,015	8,510	14,163	7,484	7,825	21,348	5,606	6,181	5,135	106,069
	Tariff Normalized, IEEE Region No Trans Line, All C	26		1,655	2,287	6,690	5,362	5,651	7,825	4,028	5,335	5,577	3,876	48,312
	Annual Normalized, IEEE Region All Levels, All Cau	4,194	4,831	3,777	17,015	8,510	14,163	5,651	7,825	21,348	5,606	6,181	5,135	104,236
	CES Cust Served	133,470	133,586	133,588	133,625	133,585	133,629	133,585	133,802	133,808	133,923	133,981	134,112	
2022	With Storms, All Levels, All Causes	6,748	479	3,892	10,390	15,814	24,646	13,486	9,572	2,527	3,898	9,529	2,289	103,270
	Tariff Normalized, IEEE Region No Trans Line, All C	2,772	479		4,149	6,431	15,723	7,155	8,136	2,050	3,898	2,379	2,289	55,461
	Annual Normalized, IEEE Region All Levels, All Cau	6,748	479	3,892	10,390	10,795	24,646	13,486	9,572	2,527	3,898	9,529	2,289	98,251
	CES Cust Served	132,621	132,702	132,795	132,899	132,760	132,711	132,829	133,010	133,020	133,252	133,360	133,466	
2021	With Storms, All Levels, All Causes	3,755	12,399	4,657	1,148	1,338	12,380	17,983	14,588	28,221	4,954	2,834	5,351	109,608
	Tariff Normalized, IEEE Region No Trans Line, All C	2,342	10,133	1,530	1,148	1,338	12,346	9,743	11,828	11,411	3,342	2,834	3	67,998
	Annual Normalized, IEEE Region All Levels, All Cau	3,755	12,399	4,657	1,148	1,338	12,380	17,983	14,588	28,221	4,954	2,834	3	104,260
	CES Cust Served	131,027	131,246	131,616	131,642	131,510	131,609	131,770	132,085	132,225	132,288	132,371	132,514	
2020	With Storms, All Levels, All Causes	4,050	27	207	18,497	1,708	19,897	18,798	29,277	10,839	6,207	11,501	4,408	125,416
	Tariff Normalized, IEEE Region No Trans Line, All C	4,050	27	206	5,491	754	12,571	14,811	18,935	9,625	4,797	1,996	56	73,319
	Annual Normalized, IEEE Region All Levels, All Cau	4,050	27	207	18,497	1,708	19,897	18,798	21,740	10,839	6,207	11,501	4,408	117,879
	CES Cust Served	130,089	130,491	130,547	130,530	130,333	130,429	130,377	130,452	130,492	130,532	130,642	130,728	
2019	With Storms, All Levels, All Causes	5,629	4,934	16,107	38,000	14,523	19,244	18,036	4,213	15,835	6,090	11,594	2,334	156,539
	Tariff Normalized, IEEE Region No Trans Line, All C	2,555	4,933	11,297	2,288	5,311	3,367	10,564	4,180	4,573	6,090	6,102	746	62,006
	Annual Normalized, IEEE Region All Levels, All Cau	5,629	4,934	16,107	15,433	14,523	19,244	15,795	4,213	11,787	6,090	11,594	2,334	127,683
	CES Cust Served	128,602	128,681	128,727	128,764	128,637	128,595	128,552	128,939	128,984	129,341	129,593	129,823	

EXECUTIVE SUMMARY

Service Quality and Demographics Analysis

Introduction

Xcel Energy contracted with TRC to provide **objective and comprehensive analysis** of the relationship between demographics, key metrics of power service reliability and quality (e.g., disconnections, outages), and low-income program participation. This work builds on analysis conducted by Dr. Gabriel Chan on behalf of the Just Solar Coalition.

This work incorporates three important improvements. First, we control for additional demographic characteristics that influence power service. Second, we use a more flexible modeling approach that allows us to see how relationships between power service and demographics are different in different communities (such as low percent POC vs. high percent POC or low income vs. high income). Third, we extend the analysis to consider outage duration, outage frequency, and participation in low-income product offerings, in addition to disconnections.

Methods

Gather additional demographic data from the American Community Survey conducted by the US Census Bureau.

Model relationships using nonparametric regression.

Vary one demographic characteristic while holding others constant to see the impact on key metrics.

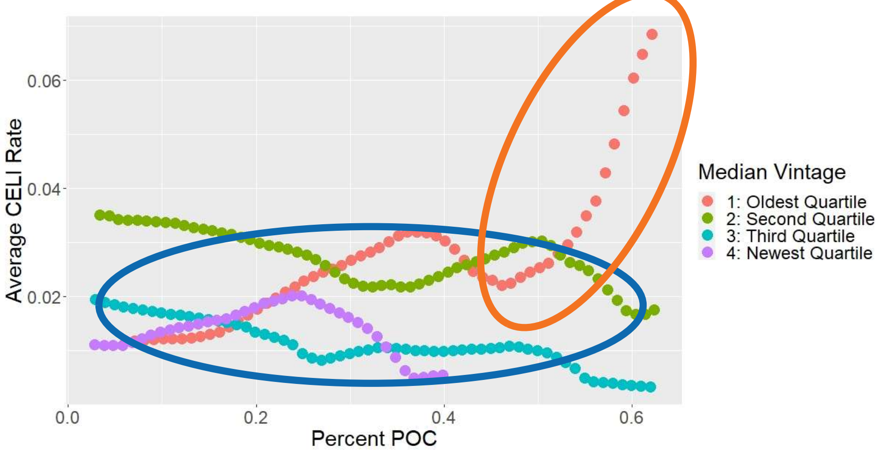
Summary of Findings

Overall, the **outage data generally does not indicate more outages or long outages in higher percent POC neighborhoods** with the exception of neighborhoods with both high percent POC and older home vintages.

After controlling for relevant demographic information, **disconnections are still higher in higher POC neighborhoods**, but the impact is smaller than indicated by previous analysis.

CIP Low Income and LIEAP **participation is higher in high percent POC Census block groups** than it is in other neighborhoods with similar characteristics.

CELI (outage duration)



A comparison across most neighborhoods shows **no overall trend in CELI with rising percent POC**.

But **among neighborhoods with older homes, CELI rises rapidly with percent POC at higher levels**.

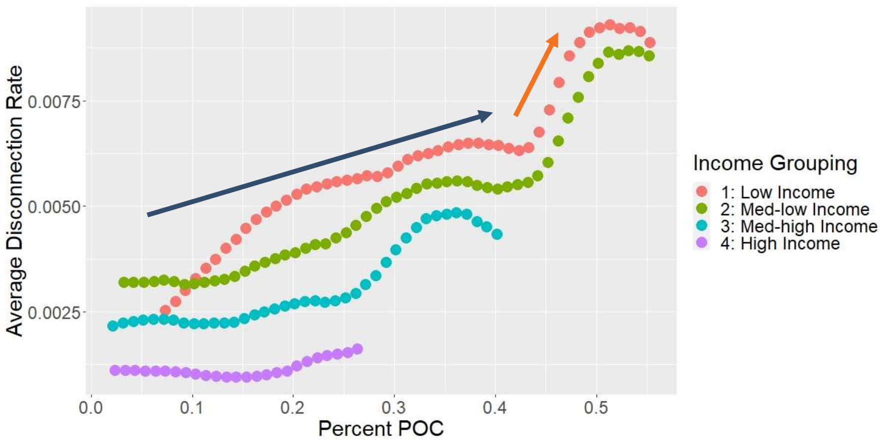
CEMI (outage frequency)

There is not a strong relationship between outage frequency and any of the explanatory variables we considered. In particular, **percent POC has no systematic relationship with CEMI**: CEMI falls, rises, falls again and then is stable as percent POC rise.

EXECUTIVE SUMMARY

Service Quality and Demographics Analysis

Disconnections



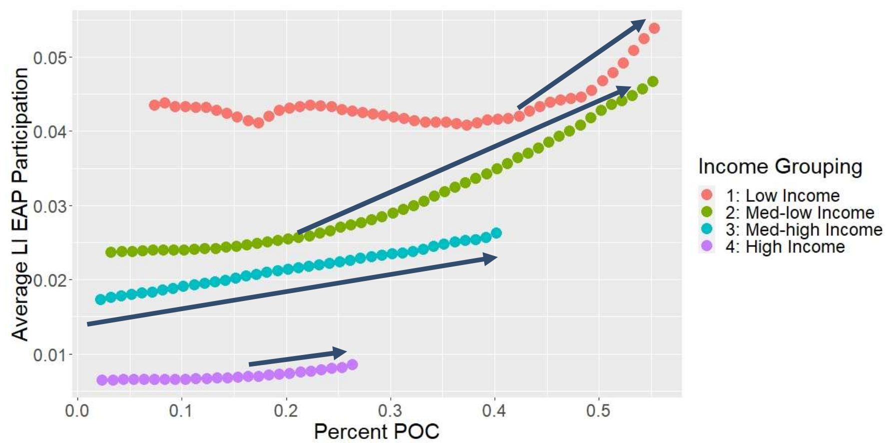
After controlling for other variables, disconnections rise with rising percent POC.

As shown in the figure at left, when holding other characteristics—including income, poverty, and home ownership—constant, **higher percent POC neighborhoods have higher disconnections than similar neighborhoods with lower percent POC**. This relationship is particularly clear in neighborhoods with greater than about 45% POC. Given the data available, we cannot distinguish between different non-payment rates and different disconnection policy application by Xcel Energy.

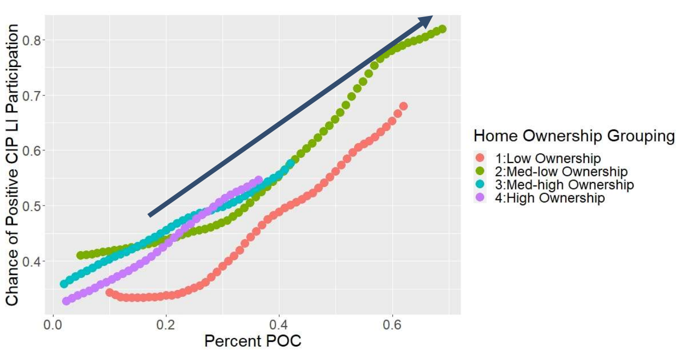
Low Income Energy Assistance Program

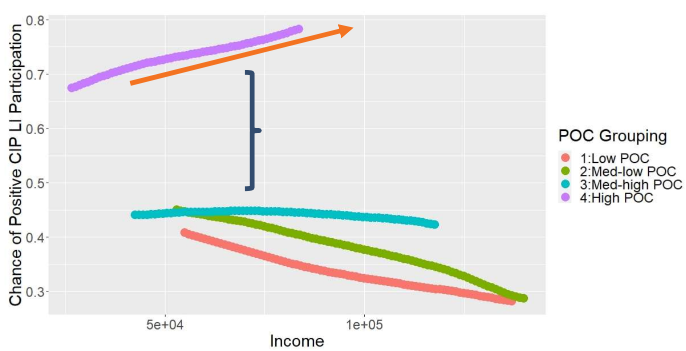
Participation in Low Income EAP is higher in neighborhoods with high percent POC after controlling for other characteristics, including income, poverty, and home ownership.

This is consistent with Xcel Energy having successful targeting and outreach with communities of color.



CIP Low Income





CIP Low Income participation is sparse, but **program does not appear to be underserving communities with high percent POC** as shown by the rising lines in the left graph and higher participation in the high percent POC quartile on the right. **It may be underserving very low income communities**, as shown in the increase in participation with rising income among very low-income communities with high percent POC in this right graph.

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Xcel Energy

Service Quality and Demographics Analysis

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1 Introduction and Background

The following memo outlines TRC's analysis of service reliability data and program participation as it relates to community demographics (e.g., ethnicity, race, and income). The overall objective of this study is to provide Xcel Energy with objective and comprehensive analysis of the relationship between these demographics and key metrics of power service reliability and quality (e.g., disconnections, outages). This work builds on analysis conducted by Dr. Gabriel Chan on behalf of the Just Solar Coalition.

Dr. Chan showed in testimony on December 6, 2022 for Docket No. E002/GR-21-630 that disconnections were higher in neighborhoods (Census block groups) with higher share of population that self-reports as a person of color ("percent POC"), even after controlling for median household income and percent of household below 185% percent of the poverty level. That analysis included linear regression models to estimate the effect of changes in percent POC on average disconnection rate, holding income and poverty constant. The analysis presented in this memo extends that analysis in three ways. First, it incorporates additional explanatory information that is relevant to bill payment and disconnection. Second, it relies on a modeling approach that allows the impacts of different explanatory variables to be more flexible, rather than assuming a straight-line relationship, allowing us to identify the ranges of values under which different characteristics are associated with changes in the variables we are studying. Third, it extends the analysis to additional key criteria: outage duration (CELI), outage frequency (CEMI), participation in the CIP Low Income programs (CIP LI), and participation in the Low Income Energy Affordability Program (LI EAP).

Overall, the outage data generally does not indicate more outages or longer outages in higher percent POC neighborhoods with the exception of neighborhoods with high percent POC and older home vintages. After controlling for relevant demographic information, disconnections are still higher in higher POC neighborhoods, but the impact is smaller than indicated by Dr. Chan's analysis. Participation in CIP LI and LI EAP are actually higher in high percent POC Census block groups.

1.1 Methodology

TRC extended previous analysis by collecting additional explanatory variables, utilizing a more general modeling approach, and modeling impacts on additional key metrics. This section describes each of these elements.

In addition to the 2019-2021 Xcel Service Quality Map data that formed the basis for Dr. Chan's analysis, we collected additional explanatory variables in order to develop a more comprehensive model of the factors that influence reliability and disconnection rates, and participation in low income energy conservation and affordability programs. Previous analysis by Dr. Chan on behalf of the Just Solar Coalition controlled for median household income and percent of the population below 185% of the poverty level. While these are undoubtedly key variables, there are likely additional factors that drive disconnections. Leaving out the additional key variables that we added leads to a bias in modeling known as omitted variable bias, where the estimated impact of included variables is biased due to their correlation with important variables that are left out. In this case, the extent to which percent POC is correlated with other relevant factors will bias the results regarding the impact of percent POC on disconnections and other key metrics. While income—as proxied by median household income and percent below 185% of poverty—is certainly a key factor in bill payment and thus disconnections, there are additional factors that are likely to drive disconnections, including wealth, ease of communication with Xcel Energy, and access to payment options. TRC gathered additional information from the American Community Survey conducted by the U.S. Census Bureau to proxy for these other factors:

- Home ownership rates along with housing vintage information provide proxies for wealth.
- Limited English proficiency, home computer access, and home internet access provide proxies for ease of communication.
- Home computer access, home internet access, and distance to the nearest payment center that accepts payments for Xcel Energy[1] provide proxies for access to payment options.

Inclusion of these additional variables significantly reduces omitted variable bias, as well as increasing model fit. These variables similarly provide relevant explanatory power for the other key metrics investigated.

TRC also used a more general modeling approach. The previous analysis relied on linear regression (also known as ordinary least squares) in its modeling approach. This is a standard and very powerful technique with many benefits. However, it imposes a constant relationship between the dependent variable and the explanatory variables across all values of these variables; that is, it assumes the relationship is a straight line or a flat surface. This will fail to provide insights into how the relationships between variables change over different ranges, which can hamper interpretation of the relationships or lead researchers to draw misleading conclusions. TRC addressed this drawback by using a nonparametric modeling approach known as nonparametric kernel smoothing that allows variables to have more flexible relationships; that is, it allows relationships to be curved lines or curved surfaces. This modeling technique is essentially a statistically-based form of moving average that uses the data “nearby” any given point to estimate the average value at that point. “Nearby” is determined by how well the model predicts outside the sample at each combination of distances and how well it avoids overfitting.[2] That is, the fitted value in a linear regression uses a straight line relationship with constant slope that is determined to fit best over the full range of values, but the fitted value in a kernel smoothing regression will be based on the nearby values and their changes. This approach combines the benefits of a rolling average—the ability to see how values are changing in different ways—with the benefits of a regression—measuring how each explanatory variable influences the dependent variable while holding all the other constant—while avoiding over-fitting the model and making it overly dependent on individual sample values.

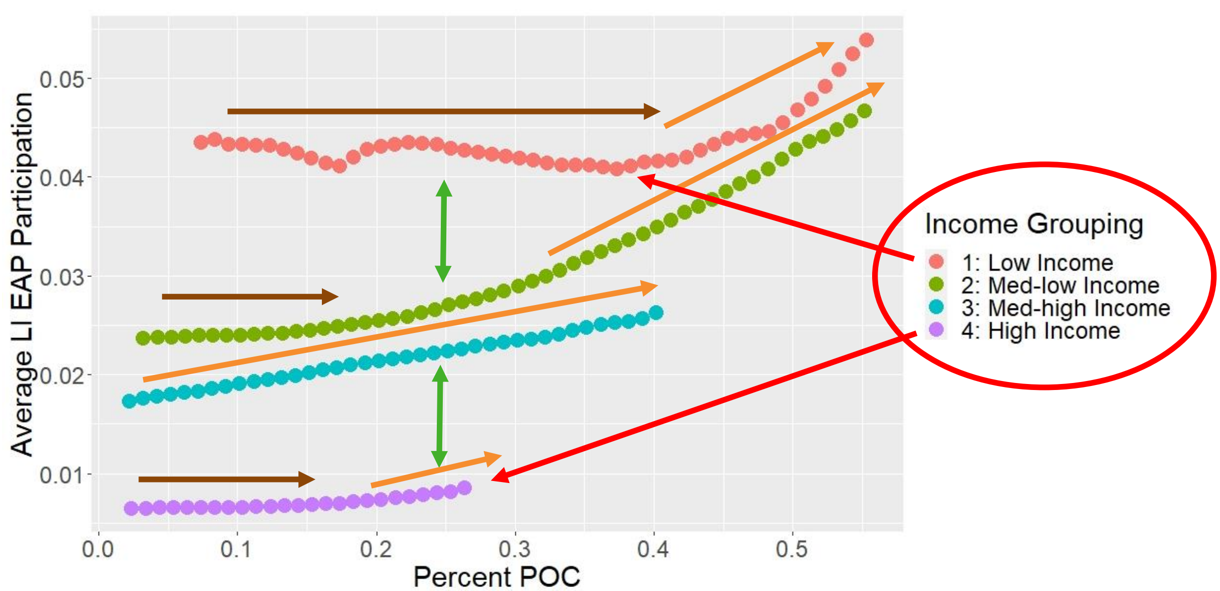
[1] Payment center locations provided by Xcel Energy.

[2] Which observations are considered “nearby” is defined by a set of bandwidths, which are determined by fitting the model thousands of times to minimize the error associated with each observation while omitting that observation from the modeling dataset. This avoids overfitting the model, which would lead to it fitting observation in the sample, but not the overall relationships between variables.

Our analysis uses both data visualization of the modeled results and quantitative interpretation of average marginal impacts. In most of the figures presented in the following section, we leveraged the flexibility of the modeling framework with the ability of the regression to hold all equal and only let the dependent variable and one explanatory variable change (usually percent POC). To accomplish this, we divided the sample into four equal quartiles by another key explanatory variable—such as median household income or home ownership rate—and calculated the average value of the other independent variables in that quartile. Then we held all of these values constant and calculated the fitted values from the model over a range of values for the one explanatory variable we analyzed. Because the fitted values in the model were calculated based on the sample values "nearby" this point (that is, within the set of bandwidths determined by the model) this showed us how the dependent variable changed with the explanatory variable we analyzed holding all others constant.

Figure 1 provides an example showing the impact of changing percent POC on average participation in LI EAP (which will be discussed below). The series of light red, green, blue, and purple dots represent the values for the low, medium-low, medium-high, and high-income quartiles as percent POC varies but holding all other values at their average within that quartile. As shown by the green arrows, the average LI EAP participation is higher for lower levels of income at all values of percent POC. As shown by the brown and orange arrows, participation is roughly steady at lower values of percent POC but then begins to rise (except for the medium-high quartile which has a steady rise throughout). The point at which participation begins to rise is higher in the lower income quartiles than in the high income quartile.

Figure 1. Example figure



For some of the key metrics, we also present a table of average marginal impacts. For a typical linear regression those are equal to the model coefficients (slopes). For a kernel smoothing regression there is no overall model slope, but the model produces a slope estimate as well as a fitted value for each point. The marginal impacts presented in Tables 1 and 2 below were calculated based on the average slope with respect to each explanatory variable for the observations in the dataset.

The additional data and flexible modeling approach improved the analysis, but do not address the challenge of relying on aggregate data. That is, we had information available at the Census block group-level, but not at an individual account-level. Measures of association between average characteristics in aggregated units are not necessarily equivalent to the measures at the individual level. Making these associations in aggregate is known as the ecological fallacy, which is unavoidable given the nature of the data available.

2 Findings

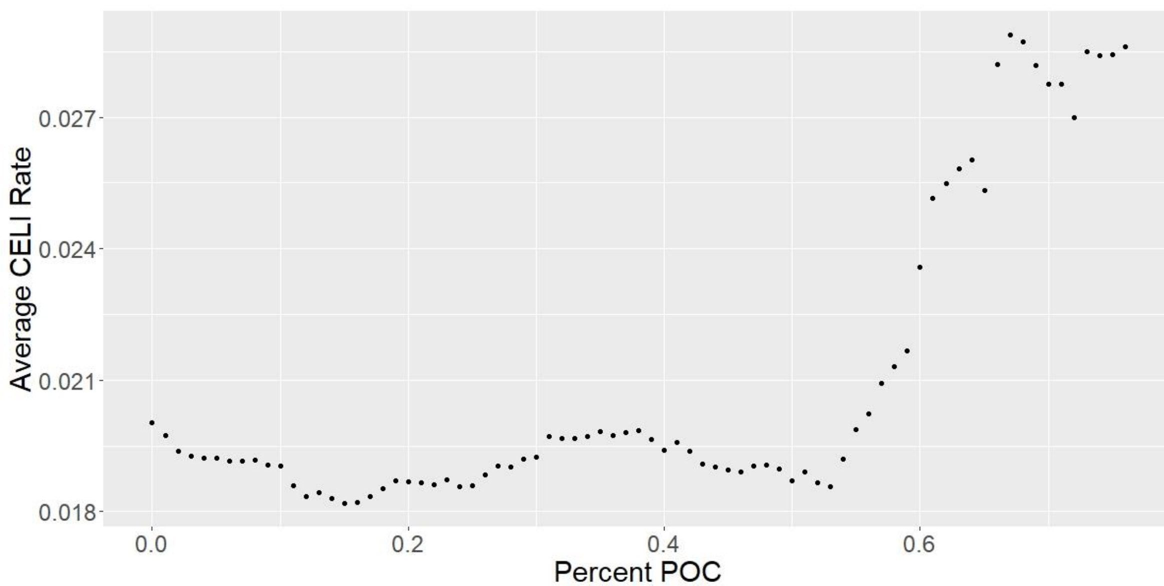
This section presents the findings from TRC's analysis for CELI, CEMI, disconnection, LI EAP, and CIP LI.

2.1 Customers Experiencing Lengthy Interruptions (CELI)

The racial composition of a neighborhood does not have a strong relationship with outage duration, except among neighborhoods with old housing stock and high percent POC where the highest CELI rates are observed and CELI rates rise with percent POC.

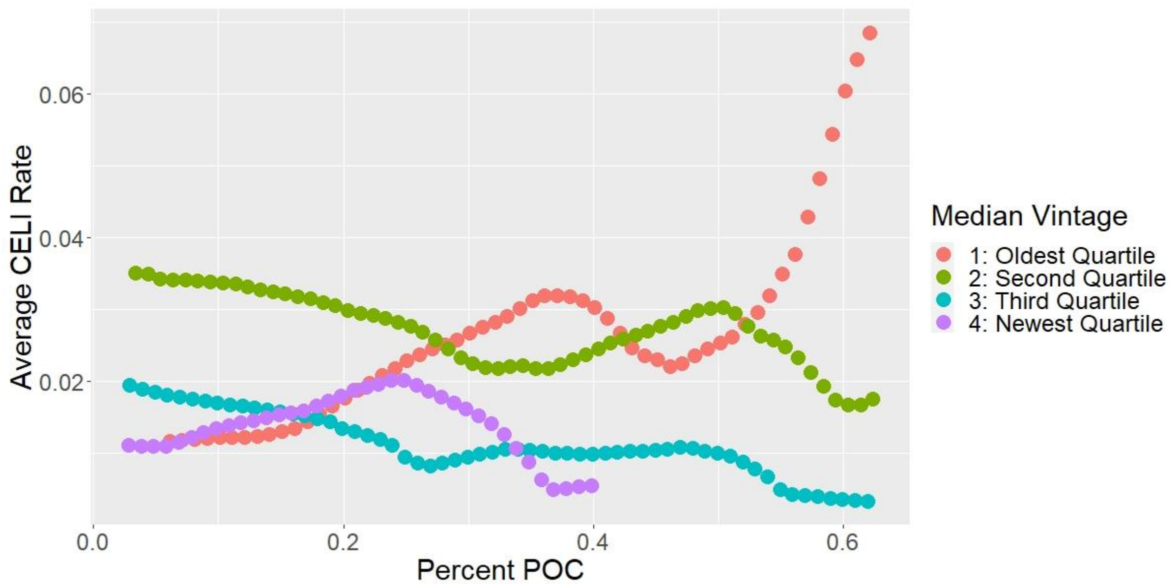
CELI is a measure of how many customers experienced an outage of 12 hours or longer. The occurrence of an outage is generally out of customers' direct control, but duration may be related to how quickly it is reported and in some cases may require other actions by customers, such as hiring an electrician to repair a broken overhead service mast. Overall, CELI is relatively flat with increasing percent POC for values less than about 50% POC and then rises, as shown in Figure 2.

Figure 2. Average CELI vs. Percent POC



Once controlling for other variables through the nonparametric regression model, we can see that this increase is isolated primarily within Census block groups with older housing, as shown in Figure 3. The model used for this analysis includes Median Home Age, Median Household Income, Percent POC, Home Ownership Rate, Percent Below 185% Poverty, Limited English Percentage, Percent with No Internet, and Distance to Payment Center and has a model fit R^2 of 0.467. For values of percent POC lower than roughly 50%, there is no clear relationship between CELI and housing vintage or percent POC. For values above roughly 50% POC, CELI rises substantially for Census block groups in the oldest median vintage quartile, but declines for Census block groups in the second and third quartiles.[3]

Figure 3. Average CELI vs. Percent POC by Vintage Quartile



[3] There are not enough Census block groups in the newest quartile of housing vintage and high percent POC for reliable estimates.

These Census block groups are clustered in three areas in North Minneapolis, South Minneapolis, and surrounding downtown St Paul, as shown in blue in Figure 4 also shows the outlines of Hennepin and Ramsey Counties. The Census blocks groups in South Minneapolis are in the same general area as Census block groups identified by Xcel Energy as impacted by civil unrest in 2020, but only three of the block groups overlap between the two lists. This demonstrates that the overall result may be somewhat impacted by the civil unrest but is not due solely to civil unrest.

Figure 4. Census Block Groups with High Percent POC and High CELI

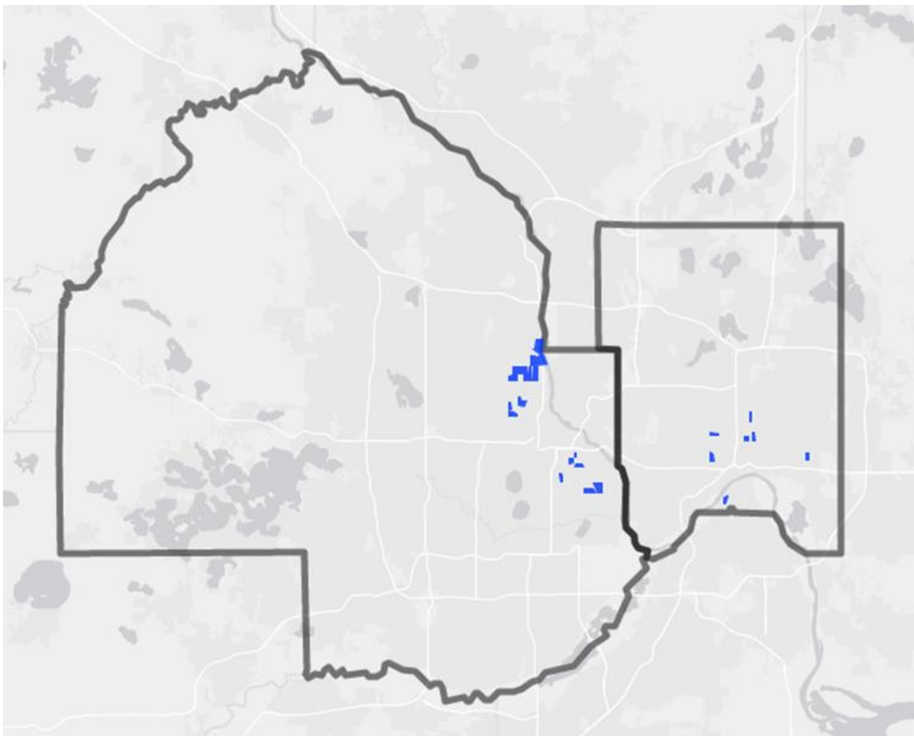


Table 1 shows two measures of the average marginal impacts of each explanatory variable on CELI:

- The first column provides the variable description.
- The second column provides the average marginal impact of a one percentage point increase in each explanatory variable on CELI.
- The third column presents the impact of a one percentage point change in each explanatory variable relative to the impact of a one percentage point change in percent POC. So, percent POC is fixed to 100% and a one percentage point change in median home age, home ownership rate and percent with no internet access are all associated with a larger average change in CELI than a one percentage point change in percent POC.
- The fourth column presents the average marginal impact of a one standard deviation change in each explanatory variable.

- The fifth column presents the impact of a one standard deviation change in each explanatory variable relative to the impact of a one standard deviation change in percent POC. So, percent POC is fixed to 100% and a one standard deviation change in median home age, home ownership rate and distance to payment center are all associated with a larger average change in CIP LI than a one standard deviation change in percent POC.

Table 1. Average Marginal Impacts of Explanatory Variables on CELI

Variable	Percentage Point Impact	Percentage Point Impact (relative to %POC)	Standard Deviation Impact	Standard Deviation Impact (relative to %POC)
Median Home Age	-7.07x10^(-5)	N/A[a]	-0.00131	-107%
Median Household Income	1.12 x10^(-5)	N/A[a]	0.000754	62%
Percent POC	5.34 x10^(-3)	100%	0.001222	100%
Home Ownership Rate	0.0114	213%	0.002964	243%
Percent Below 185% Poverty	-5.52 x10^(-17)	0%	-9.70 x10^(-18)	0%
Limited English Percentage	-1.36 x10^(-3)	-25%	-7.98 x10^(-5)	-7%
Percent with No Internet	0.0135	253%	0.000781	64%
Distance to Payment Center	4.01 x10^(-5)	N/A[a]	0.005052	413%

a: Because these variables are not measured in percentage points, the percentage point comparison is not directly applicable.

Table 1 presents the overall average marginal impacts for the explanatory variables on CELI, but as shown in Figure 4, the impact of percent POC is very different among neighborhoods with older homes and percent POC above roughly 50%. Among this smaller group, the average marginal impacts are much larger and positive, so the modest values in Table 1 (5.34 x10^(-3)) combine a large positive value for the small subset with older homes and high percent POC (0.0516) with a smaller value for the remainder of Census block groups (1.744505 x10^(-3)). This average marginal impact for neighborhoods with older homes and high percent POC is roughly four and a half times as large as the impact of a one percentage point change in the home ownership rate, which is the variable with the largest marginal impact across both percentage point and standard deviation.

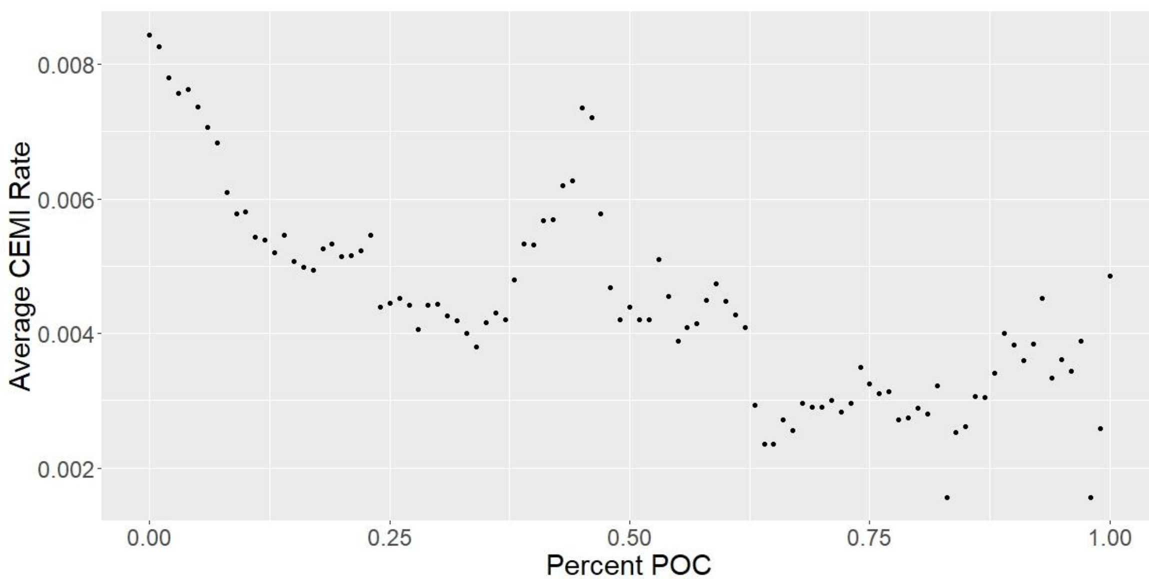
Though it is unclear from the data exactly why this is the case, this increase with percent POC in neighborhoods with older housing stock may be attributed to a combination of larger and more established vegetation cover and infrastructure age in older neighborhoods. Because these neighborhoods were developed earlier than other neighborhoods, the distribution infrastructure is likely to be older on average and is less likely to be underground construction, making it more susceptible to disruption from vegetation.

2.2 Customers Experiencing Multiple Interruptions (CEMI)

There is not a strong relationship between outage frequency and any of the explanatory variables we considered.

CEMI (Customers Experiencing Multiple Interruptions) is a measure of how many customers experience six or more outages. Outage frequency is generally out of customers' direct control. None of the variables we considered had particularly notable explanatory power for the variation in CEMI across different Census block groups. While the model had relatively good fit (R^2 of 0.545), none of the patterns that emerged from the relationship between CEMI and Median Household Income, Percent POC, Percent of Homes Built before 1970, Home Ownership Rate, Limited English Percentage, Percent with No Internet, and Distance to Payment Center showed meaningful relationships. Figure 5 shows the overall pattern, which declines, increases, declines again, then is roughly stable before increasing again. Figure 6 shows the analysis broken up by income grouping. No clear or coherent pattern is evident.[4] That is, while these variables can help us know the average CEMI rate, there is not an overall clear pattern of the ways in which they influence CEMI.[5]

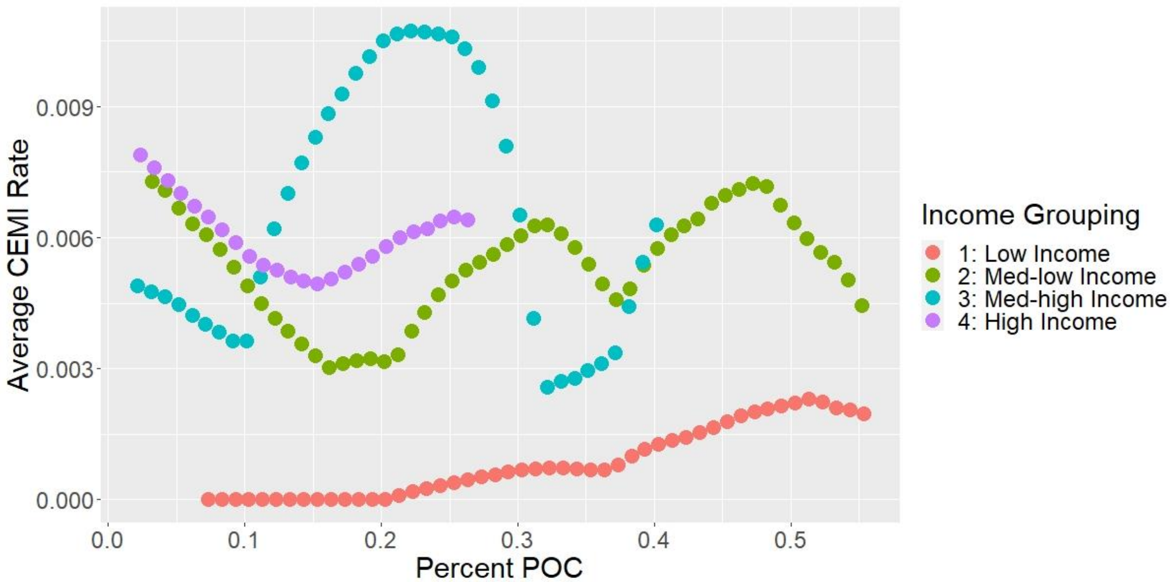
Figure 5. Average CEMI vs. Percent POC



[4] Because there is no coherent relationship we are not presenting a table of average marginal effects, as we are for CELI and disconnections, because it would not represent meaningful results.

[5] A linear regression of average CEMI on the same variables yields an R^2 of 0.016, significantly less than the 0.545 of the nonparametric regression.

Figure 6. Average CEMI vs. POC by Income

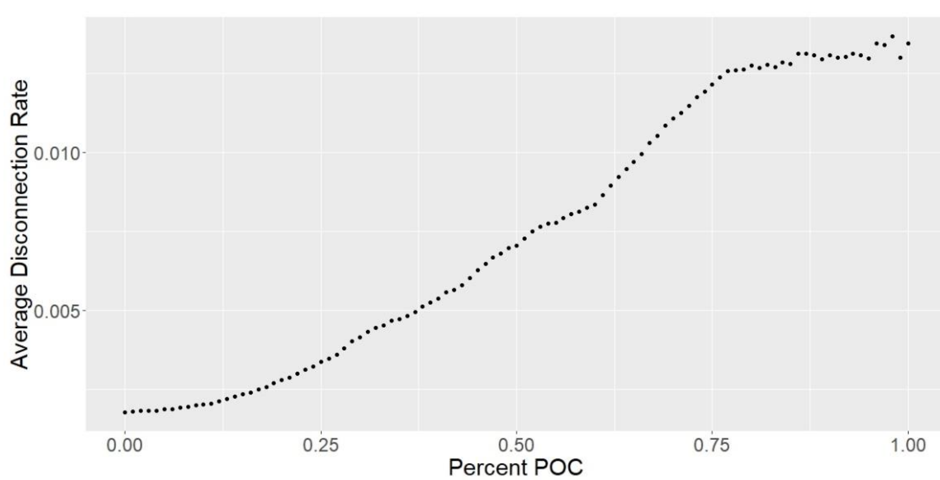


2.3 Disconnections

After controlling for additional variables and allowing more flexibility, the racial composition of a neighborhood still has a strong correlation with the disconnection rate, but the impact is smaller than previous analysis indicated.

As discussed in the previous modeling work performed by Dr. Chan on behalf of the Just Solar Coalition, disconnections do show a clear relationship with percent POC, as shown in Figure 7. There is a gradual increase in the average disconnection rate through the range of percent POC values.

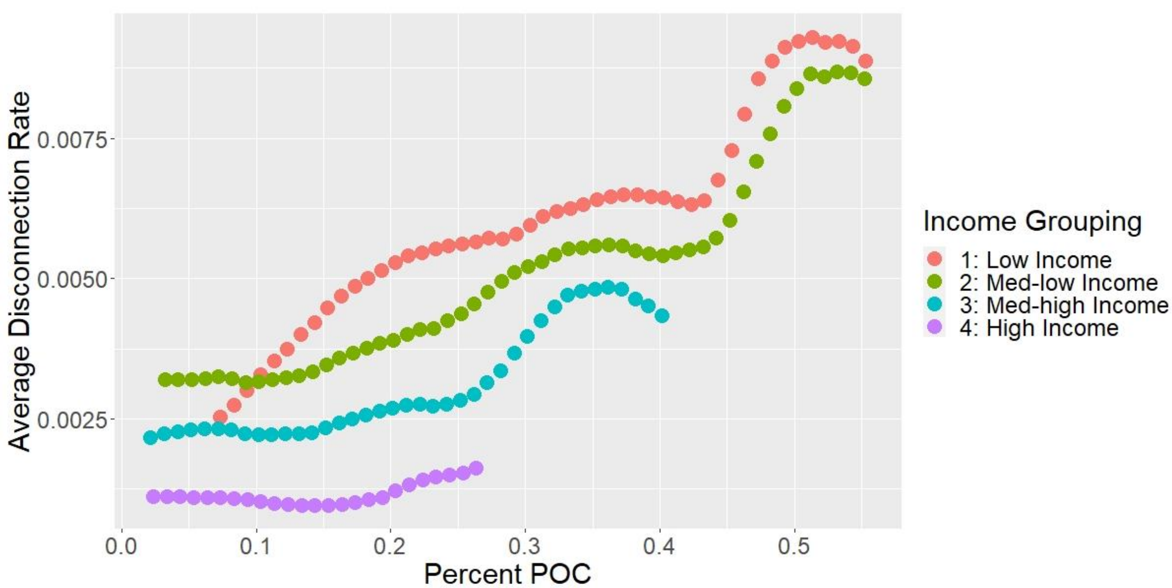
Figure 7. Average Disconnections vs. Percent POC



After controlling for relevant variables, this overall pattern remains, although the impact of percent POC is attenuated somewhat. The model used for this analysis includes Median Household Income, Percent POC, Home Ownership Rate, Percent Below 185% Poverty, Limited English Percentage, Percent with No Internet, Distance to Payment Center, and Percent of Homes Built before 1970 and has a model fit R^2 of 0.507.[6] Figure 8 shows the relationship between disconnection rate and percent POC by income quartile, holding all other explanatory variables constant at their average in the quartile. This figure shows that disconnections are higher in low income areas at essentially all levels of percent POC. It also demonstrates that disconnections rise with percent POC across all income groupings. A similar relationship exists when grouping Census block group by home ownership quartile. Because disconnection rate is available by Census block group, but non-payment rate is not, we cannot distinguish between three possible reasons for this results:

1. There is a higher rate of non-payment in higher percent POC neighborhoods (and Xcel is applying the disconnect policy uniformly or non-uniformly);
2. The non-payment rate is the same and Xcel is applying a disconnect policy in a non-uniform way; or,
3. The non-payment rate is the same and Xcel is applying the disconnect policy in a uniform way, but that people in different communities are accessing some of the elements of the disconnect policy (such as payment plans) in different ways.

Figure 8. Average Disconnection vs. Percent POC by Income



[6] This compares to an R^2 of 0.2816 for linear regression using the variables from the previous analysis on behalf of the Just Solar Coalition using the same dataset and R^2 of 0.337 for the original results, which relied on a dataset with slightly older values.

Table 2 shows two measures of the average marginal impacts of each explanatory variable on disconnections.

- The first column provides the variable description.
- The second column provides the average marginal impact of a one percentage point increase in each explanatory variable on disconnections.
- The third column presents the impact of a one percentage point change in each explanatory variable relative to the impact of a one percentage point change in percent POC. So, percent POC is fixed to 100% and a one percentage point change in median income and percent of houses built before 1970 each have about one third the impact of a one percentage point increase in percent POC.
- The fourth column presents the average marginal impact of a one standard deviation change in each explanatory variable.
- The fifth column presents the impact of a one standard deviation change in each explanatory variable relative to the impact of a one standard deviation change in percent POC. So, percent POC is fixed to 100% and a one standard deviation change in median income is associated with a roughly equivalent change as a one standard deviation change in percent POC, though in the opposite direction. While the overall pattern of increasing disconnections with increasing percent POC remains with the inclusion of additional variables and a more flexible modeling approach, the magnitude of impact is decreased by about one half.[7]

[7] This decrease appears to be driven more by the flexible modeling approach than by the inclusion of additional explanatory variables. A comparison of linear regression coefficients for a model with only percent POC, median income, and percent below 185 of poverty and a model that includes the additional explanatory variables shows similar coefficients on percent POC.

Table 2. Average Marginal Impacts of Explanatory Variables on Disconnections

Variable	Percentage Point Impact	Percentage Point Impact (relative to %POC)	Standard Deviation Impact	Standard Deviation Impact (relative to %POC)
Median Household Age	-1.75 x10^(-5)	N/A[a]	-0.00117	-95%
Percent POC	5.38 x10^(-3)	100%	0.001231	100%
Home Ownership Rate	5.34 x10^(-3)	0%	-6.90 x10^(-6)	-1%
Percent Below 185% Poverty	-2.65 x10^(-5)	12%	0.000113	9%
Limited English Percentage	6.43 x10^(-4)	0%	-6.29 x10^(-19)	0%
Percent with No Internet	-1.36 x10^(-3)	-17%	-5.33 x10^(-5)	-4%
Distance to Payment Center	2.71 x10^(-18)	N/A[a]	3.41 x10^(-16)	0%
Percent of Homes Pre- 1970	-1.73 x10^(-3)	N/A[a]	-0.00051	-41%

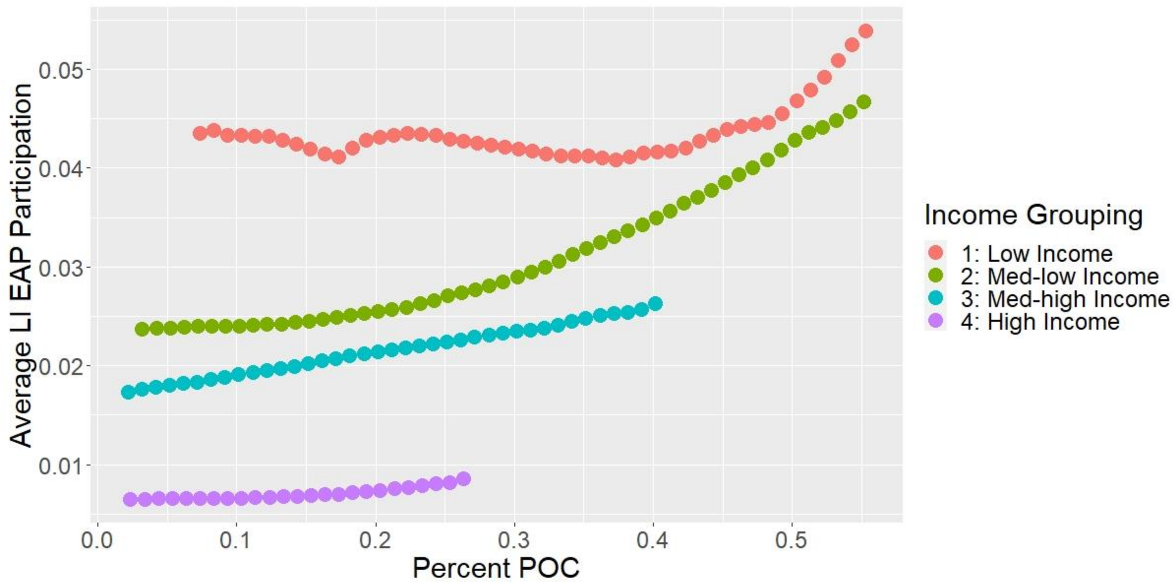
a: Because these variables are not measured in percentage points, the percentage point comparison is not directly applicable.

2.4 Low Income Energy Assistance Programs (LI EAP)

After controlling other factors, LI EAP participant is higher in neighborhoods with high percent POC. This is consistent with Xcel being successful at targeting program impacts to disadvantaged communities.

Low Income Energy Assistance Program (LI EAP) participation includes participation in any of the programs provided by the State of Minnesota or Xcel Energy to have qualified households pay their gas or electric bills. As such, participation requires both eligibility based on income and households to take steps to enroll. This makes analysis based on Census block group-level data—rather than household-level data—even more challenging than with disconnections and outages. After controlling for relevant explanatory variables, the participation pattern shows higher participation rates in Census block groups with higher percent POC, as shown in Figure 9. The model used for this analysis includes Median Household Income, Percent POC, Home Ownership Rate, Percent Below 185% Poverty, and Distance to Payment Center and has a model fit R^2 of 0.721. Other relationships in the data are as expected: participation rises with the percent of homes below 185% of poverty and declines with median income. The most striking factor is the extent to which participation rates are higher with higher percent POC holding income and poverty constant. This is consistent with Xcel Energy and the State of Minnesota being successful at conducting outreach and enrollment in communities with high percent POC and does not indicate any type of under-performance.

Figure 9. LIEAP Participation vs. Percent POC by Income



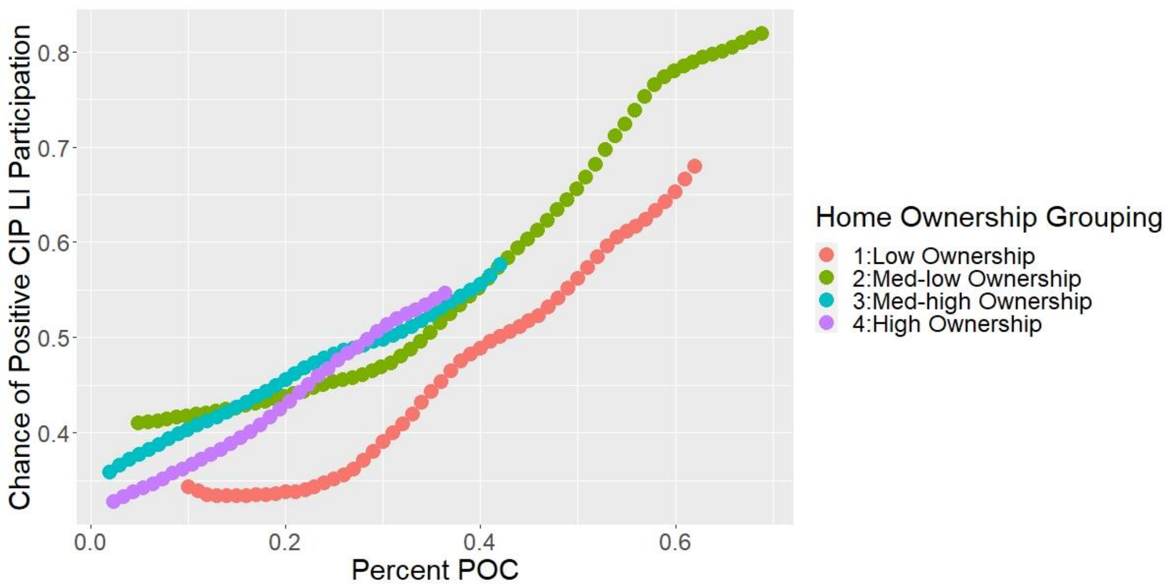
2.5 CIP Low Income (CIP LI)

CIP Low Income participation is sparse, but the program does not appear to be underserving communities with high percent POC. It may be underserving very low income communities, which is not unexpected given the challenges of programs designed to make improvements to building stock in areas with low capital and split incentives, even though the program is designed to address those barriers.

The CIP LI programs include the Low-Income Home Energy Squad, the Home Energy Savings Program, and the Multi-family Energy Savings Program. These programs provide energy efficient equipment, information, and other support in various forms. Because it focuses on residential applications where there are many renters rather than owners, this type of program faces a split incentives barrier where some of the benefits accrue to tenants through reduced utility bills and some accrue to owners through improved capital stock. There are also additional challenges of coordinating logistics and consent between tenants and owners.

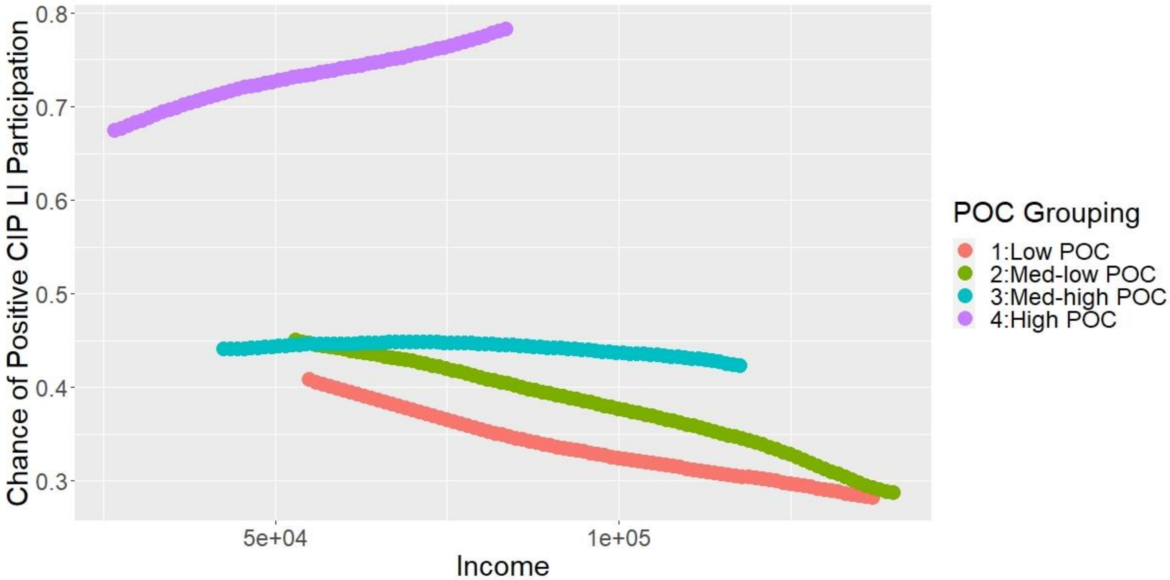
Overall participation in CIP LI is relatively sparse, making an analysis at the Census block group level more difficult. Only 42% of Census block groups had positive participation with the remainder at zero participation, and overall average participation at 0.19%. This compares to 94% of Census block groups with positive participation in LI EAP and average LI EAP participation of 2.9%. To address this challenge with the data, we analyzed the likelihood that a Census block group had positive participation, rather than analyzing the participation rate directly. After controlling for relevant explanatory variables, the likelihood that a Census block group has positive participation rises substantially with percent POC even after controlling for income, poverty, and home ownership, as shown in Figure 10. The model used for this analysis uses an indicator that there was positive (i.e. not zero) participation in the Census block group and includes Median Household Income, Percent POC, Home Ownership Rate, Percent Below 185% Poverty, Limited English Percentage, Percent with No Internet, and Distance to Payment Center, and has a model fit R^2 of 0.152. This model fit is quite low and indicates the fact that very similar Census block groups have a mix of positive and zero participation due to the overall sparse positive participation. The overall pattern, which is replicated in similar comparisons with income and grouping by percent POC rather than home ownership, is that percent POC is the much stronger determinant of positive participation. Except for slightly lower participation within the low home ownership quartile (which makes sense given the split incentive and coordination challenges mentioned above), participation is very similar across home ownership and income levels for a fixed percent POC but increases substantially as percent POC increases.

Figure 10. Change of Positive CIP LI Participation vs. Percent POC by Home Ownership



Participation does appear to increase somewhat as income increases from a low level, as shown by the positive slope of the purple line (high percent POC quartile) and slightly positive slope at the low end of income for the blue line (medium-high percent POC) in Figure 11. This may indicate an opportunity to improve performance among the lowest-income neighborhoods, but there is no evidence that the participation is under-performing relative to percent POC.

Figure 11. Chance of Positive CIP LI Participation vs. Income by Percent POC



3 Conclusions

This analysis indicates that in general, Xcel Energy performs well on key electric reliability and service quality metrics, and low-income program participation metrics. The analysis identified three places where there are opportunities for improvement. First, there have been more long-duration outages in high percent POC communities that also have older housing vintage. There may be an opportunity to assess vegetation management practices in those neighborhoods or assess distribution equipment vintage that could lead to longer outages. Second, disconnections are higher in high percent POC neighborhoods even after controlling for other relevant explanatory variables; we cannot determine from the data if this is due to higher non-payment rates or differential application of disconnection policy. Given the success of enrollment in the LI EAP and CIP LI programs in high percent POC neighborhoods, there may be opportunities to leverage those relationships to identify a path to address the disparity in disconnections. Finally, CIP LI participation may be lower in very-low-income communities. This may present an opportunity to conduct additional outreach or assess program barriers to participation in those communities.