Docket	:	A.25-06-017
Exhibit Number	:	CA-08
Commissioner	:	M. Baker
Admin Law Judge	:	R. Haga
Witness	:	T. Holzschuh

PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY ON CONSTRUCTION PRACTICES FOR MOUNTAIN VIEW FIRE COST-RECOVERY APPLICATION

Reasonableness of Construction Practices Prior to Ignition

PUBLIC

San Francisco, California
December 12, 2025

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CONSTRUCTION PRACTICES PRIOR TO IGNITION

I. INTRODUCTION

This exhibit pertains to the application of Liberty Utilities (CalPeco Electric) LLC, ("Liberty") to recover costs associated with the Mountain View Fire (Application 25-06-017). Here, the Public Advocates Office (Cal Advocates) presents evidence regarding the reasonableness of Liberty's construction practices. Specifically, this exhibit relates to Exhibit Liberty-03: Prudence of Operations, Liberty's testimony on design and construction of Liberty's power lines and how Liberty's construction practices relate to the Mountain View Fire ignition.

II. LIBERTY'S CONSTRUCTION PRACTICES ALLOWED PHASE-TO-PHASE CONTACT AND ITS OUTAGE HISTORY DEMONSTRATES POOR CONSTRUCTION PRACTICES

Liberty allowed a number of phase-to-phase[1] contact events and demonstrated poor construction on Topaz 1261 (the circuit involved with the ignition).[2] Not only was there phase-to-phase contact at the site of the ignition,[3] Liberty had a history of excessive phase-to-phase contacts on Topaz 1261.[4] Furthermore, the high number of outages on Topaz 1261[5] is evidence of poor construction practices.

A. General Order 95 requirements prohibiting phase-to-phase contact were in effect at the time of construction and ignition

The Commission's General Order 95 (GO-95) regulates phase-to-phase clearance on conductors, like those involved with the Mountain View Fire.[6] Table 2 of GO-95

[1] Contact between different phases results in a large, abnormal electron flow. "Phase" refers to the angle of the sinusoidal voltage, given a specific magnitude or root mean square of the voltage waveform.

[2] Exhibit (Ex.) Liberty-02: Ignition at 3.

[3] Ex. Liberty-02: Ignition at 8.

[4] Attachment 1, Liberty's 2020 Wildfire Mitigation Plan, Attachment 5 – Section 4.1 (Attachment 1).

[5] Attachment 2, Liberty, *Electric System Reliability Annual Report 2020*, July 15, 2021 at 23, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2020-liberty-annual-reliability-report.pdf. Accessed December 5, 2025. (Attachment 2).

[6] GO-95 at III-29.

requires that "conductors, taps, or lead wires of the same circuit" at "7,500 – 20,000 Volts" have a clearance of six inches.[7] However, Rule 38 states, "the clearances in Table 2 shall in no case be reduced more than 10 percent … because of temperature and loading."[8] Therefore, the clearance requirement for the Topaz 1261 Circuit at 12.5 kV[9] is at least 5.4 inches at all times. Accordingly, the mere occurrence of contact between the phases (known as wire slap), implies insufficient clearance compared to the requirements of GO-95.

Liberty states that "records indicate that the East pole in place at the time of the fire was installed in 1947, and the West pole in 2000 or 2001."[10] Since these Rule 38 and Table 2 requirements have not changed since 1941,[11] GO-95 required Liberty to maintain at least 5.4 inches of clearance between phases on the Topaz 1261 Circuit.

B. There was evidence of phase-to-phase contact at the site of ignition

As evidenced by Liberty's testimony, immediately before the ignition was first reported there was phase-to-phase contact on the subject span where the California Department of Forestry and Fire Protection (CAL FIRE) determined that the fire started. To confirm the lack of clearance, Liberty's witness, G. Fowler, states:

> The center and field phase conductors show evidence of recent arcing consistent with phase-to-phase contact on November 17, 2020. The area of contact was approximately mid-span between the West and East Poles, including at the location where the field phase conductor ultimately separated and fell to the ground. The field

[7] GO-95 at III-29.

[8] GO-95 at III-27. Temperature causes additional slack through thermal expansion and tensile loading causes additional slack through the elasticity of materials. GO-95 has allowances for these effects when determining minimum clearances.

[9] Attachment 1.

[10] Attachment 3, Liberty's Amended Response to CalAdvocates-LIB-A2506017-018, Question 4 (Attachment 3).

[11] Original GO-05 Rule 38, Decision 34884, December 23, 1941, available at https://files.cpuc.ca.gov/LegacyCPUCDecisionsAndResolutions/Decisions/Decisions_D25901_to_D40599/D34884_19411223_C4324.pdf. Accessed December 5, 2025.

> phase conductor exhibited arcing and melting on each end of the separation point.[12]

Here, separation refers not to the distance between conductors, but to where the conductor broke. Clearly, there was no clearance between the two conductors when they contacted together, forming an arc. Because the conductor in question was #4 aluminum conductor steel reinforced (ACSR),[13] the arc was hot enough to melt the steel and aluminum.[14]

Furthermore, Liberty's witness T. Fee describes more evidence that there was inadequate clearance between the wires of different phases:

> A protection device on Liberty's system recorded electrical faults on the Topaz 1261 Circuit around the time of the ignition consistent with phase-to-phase contact and the conductor separation.[15]

From the grid sensor (i.e. the 1261 R2 Recloser)[16] data and the indication of arcing, there was evidence that contact (i.e. a separation of zero inches) between two conductors of different phase occurred. Indeed, Liberty appears to concede this point, stating that "the conductor showed damage consistent with phase-to-phase contact."[17] Liberty is responsible for keeping wires at different voltages or phases separated from one another and in compliance with GO-95 at all times.

C. There was a history of numerous phase-to-phase contacts and other outages on the Topaz 1261 Circuit

According to Liberty's wildfire mitigation plan submission in 2020, Liberty had 18 "wire slap" (i.e. phase-to-phase contact) events on the Topaz 1261 Circuit between

[12] Ex. Liberty-02: Ignition at 8 (internal footnote omitted).

[13] Ex. Liberty-03: Prudence of Operations at 8.

[14] Ex. Liberty-02: Ignition at 8.

[15] Ex. Liberty-02: Ignition at 3.

[16] Ex. Liberty-02: Ignition at 3.

[17] Ex. Liberty-02: Ignition at 1.

2015 and 2019.[18] Since the clearance at the site of phase-to-phase contact is zero, this implies that Liberty did not maintain the required clearances to meet GO-95 18 times on the Topaz 1261 between 2015 and 2019.

The repeated phase-to-phase contact indicates subpar construction and maintenance practices which led to the phase-to-phase contact. Proper construction ensures that, outside of damage to poles and equipment, phase-to-phase contact would not occur. In other words, temperature, ice loading, and wind would all be accounted for during construction, ensuring none of these factors could cause phase-to-phase contact.[19] Logically, the numerous wire slap events on the Topaz 1261 Circuit implies that there were inadequate construction and maintenance on that circuit.

Furthermore, the Topaz 1261 Circuit had an unacceptable outage history. In its 2020 electric reliability report, Liberty provided historical system average interruption duration index (SAIDI) (outage minutes per customer per year) metrics for its Topaz 1261 Circuit.[20] These data are provided below along with Liberty[21] and PacifiCorp's[22] California distribution system SAIDI (with major event days included):

[18] Attachment 1.

[19] GO-95 at III-27, IV-7, IV-8.

[20] Attachment 2 at 23.

[21] Attachment 2 at 1.

[22] PacifiCorp is chosen for this analysis because PacifiCorp is the geographically closest investor owned utility in California that did not institute a large public safety power shutoff (PSPS) between 2016 and 2020. See Attachment 4, Commission's Safety Enforcement Division, *PSPS Dashboard*, available at https://www.arcgis.com/apps/dashboards/ecd21b1c204f47da8b1fcc4c5c3b7d3a. Accessed December 5, 2025. (Attachment 4). Attachment 5, PacifiCorp, *Annual California Electric Reliability Report Calendar Year 2021 Review*, July 15, 2022, at 9, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2021-pacificorp-annual-electric-reliability-report.pdf. Accessed December 5, 2025. (Attachment 5).

Table 1: System Average Interruption Duration Index (SAIDI, with major event days included) for Liberty's Topaz 1261 Circuit, Liberty's distribution system, and PacifiCorp's California distribution system.

Year	Liberty's SAIDI for its Topaz 1261 Circuit	Liberty's distribution system SAIDI (with major event days included)	PacifiCorp's California distribution system SAIDI (with major event days included)
2016	1,930.4	213.6	130.8
2017	3,004.5	1,597.4	421.8
2018	2,393.8	288.0	202.5
2019	3,040.6	416.5	419.7
2020	2,615.2	181.6	251.5

As can be seen in Table 1, Liberty's Topaz 1261 Circuit (Liberty's worst performing circuit in 2020)[23] had between seven and 15 times the number of outage minutes per customer that PacifiCorp's system had between 2016 and 2020. During this same period, Liberty's Topaz 1261 Circuit also performed far worse than Liberty's overall distribution system in California. This level of outages reveals a chronically poor performing circuit, which Liberty knew was problematic.[24] These outages further highlight that Liberty's response (i.e. its maintenance and construction on the line) was insufficient to mitigate numerous outages, faults, and ultimately a wildfire.

D. Liberty's power line tensioning practices were insufficient

Liberty appears to have also set slack too loose when sagging conductors. Although Liberty did not provide sagging tables for #4 ACSR, the size of conductor that failed,[25] Liberty did provide sagging tables for #2 ACSR (the closest sized conductor to

[23] Attachment 2 at 22.

[24] Attachment 6, Liberty, *Electric System Reliability Annual Report 2019*, February 1, 2020 at 21, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2019_peco.pdf. Accessed December 8, 2025. (Attachment 6).

[25] Ex. Liberty-03: Prudence of Operations at 8.

#4 ACSR that Liberty had sagging tables for).[26] For a 250-foot ruling span[27] and 300-foot span length,[28] Liberty's sagging standards state that, at 100° F, sag should be 28 inches.[29] However, this level of sag is dangerous because, with a 54-inch radial clearance at the crossarm,[30] phase-to-phase contact would be possible.[31]

III. LIBERTY FAILED TO MAINTAIN PROPER POLE LOADING RECORDS

In 2012, the Safety and Enforcement Division (SED) of the Commission stated Liberty's pole loading calculations were inaccurate. Specifically, SED's audit summary stated Liberty's "pole load calculations did not contain accurate information."[32] Accurate inputs to pole loading calculations are extremely important, and the lack of accuracy can lead to safety risks. Incorrect calculation inputs can cause a pole to fail, leading to wildfire or electrocution risk. Furthermore, erroneous calculations may go unnoticed initially but could cause failure during the high winds that often coincide with wildfire risk.

[redacted]

[26] Attachment 7, Liberty, *Overhead Distribution Conductor Stringing Guide* (CON05T) at 384, Liberty's Amended Response to CalAdvocates-LIB-A2506017-018 Question 3 (Attachment 7).

[27] A ruling span is a calculated span length that assists in sagging conductors. See Attachment 7 at 378.

[28] 300 feet was the approximate distance between the poles where the ignition occurred. See Attachment 8, Google Maps View of East and West Pole Locations. Accessed December 5, 2025. (Attachment 8).

[29] Attachment 7 at 384.

[30] 54 inches was the radial clearance at the poles nearest to the ignition for the conductors involved with the ignition. Exhibit Liberty-03: Prudence of Operations at 14.

[31] Phase-to-phase contact would result in an abnormally large electron flow or arc. The midpoint clearance with 54-inch crossarm clearance and 28 inches of sag is 54 – 2*28 = -2 inches, indicating likely contact.

[32] Attachment 9, Safety and Enforcement Division, *Audit of Liberty Utilities*, August 24, 2012, at 3, available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/safety/electric_safety_and_reliability/reports_and_audits/electric_facilities/ea2012-013.pdf. Accessed December 5, 2025. (Attachment 9).

[redacted][33]<CONF> Liberty stated, "Liberty has not identified records of pole loading calculations for the East Pole[34] dated prior to November 17, 2020."[35] [redacted].[36] [redacted][37] [redacted] [redacted].[38] [redacted]

Failing to maintain pole loading records is unacceptable. Without such records, Liberty cannot prove its poles are within safety limits.[39] In addition, Liberty's poor recordkeeping increases the chance of phase-to-phase contact or other failures. For example, if Liberty recorded the tension at a higher level than the actual tension, wire slap events may not lead Liberty to believe tension or sag is the issue.

Liberty still does not have proper pole loading calculations. When asked to provide pole loading calculations for 20 poles and towers randomly selected by Cal Advocates,[40] Liberty could locate calculations for only two poles.[41] This suggests that Liberty is likely missing pole loading calculations for a substantial portion of its poles and that Liberty was likely missing these calculations at the time of the fire. As stated

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[33] For the locations of the East and West Poles, see Ex. Liberty-02: Ignition at 4.

[34] For the location of the East Pole, see Ex. Liberty-02: Ignition at 4.

[35] Attachment 10, Liberty's Response to CalAdvocates-LIB-A2506017-019, Question 10 (Attachment 10).

[36] Attachment 11, Liberty's Response to CalAdvocates-LIB-A2506017-019, attachment "CONFIDENTIAL-Pole 266731 Loading Calculations," (Attachment 11).

[37] R. C. Hibbeler, *Engineering Mechanics Statics*, Eleventh Edition, at 383. Attachment 12, Priority Wire & Cable Inc., *Aluminum Conductor Steel Reinforced Specifications*, available at https://www.prioritywire.com/specs/acsr.pdf. Accessed December 5, 2025. (Attachment 12).

[38] Ex. Liberty-03: Prudence of Operations at 14.

[39] For instance, the safety factors in GO-95 Table 4 at IV-10.

[40] 20 random support structures were taken from Liberty's Wildfire Mitigation Plan submission of geographical information system data by Cal Advocates.

[41] Attachment 13, Liberty's Response to CalAdvocates-LIB-A2506017-036, Question 1 (Attachment 13).

before, having proper pole loading calculations is necessary for operating a safe electric grid.

IV. CONCLUSION

There is evidence that Liberty had several construction practices that were unsafe. Excessive wire slap events, such as what occurred at the ignition location demonstrate poor construction. In addition, Liberty's loose slack when tensioning power lines puts the public at an unnecessary risk. Finally, Liberty failed to maintain proper pole loading calculations, which are necessary to operate an electric grid as safely as possible.

APPENDIX A

QUALIFICATIONS OF WITNESS

PREPARED TESTIMONY AND QUALIFICATIONS

OF

TYLER HOLZSCHUH

My name is Tyler Holzschuh. My business address is 505 Van Ness Avenue, San Francisco, California. I am employed by the California Public Utilities Commission as a Utilities Engineer in the Public Advocates Office, Safety Branch.

I received a Master of Science degree in Electrical Engineering from the University of California, Los Angeles and a Bachelor of Arts degree in Math and Physics from Wesleyan University in Connecticut. I also have a professional engineering license in Mechanical Engineering in the State of California with license #39545. Since joining Cal Advocates in 2019, I have worked on analyzing the wildfire mitigation plans of Pacific Gas and Electric Company, PacifiCorp, and Bear Valley Electric Service, Inc. I have also served as an expert witness in the Aliso Canyon blowout enforcement proceeding.

Prior to joining Cal Advocates, I served as an engineer for the Commission in the Gas Safety and Reliability Branch, where I analyzed natural gas transportation companies' adherence to state and federal regulations.

This concludes my statement of qualifications.

APPENDIX B

SUPPORTING ATTACHMENTS

LIST OF ATTACHMENTS FOR APPENDIX B

Attachment	Title	Bates No.
Attachment 1	Liberty's 2020 WMP Attachment 5 Section 4.1 Wire Slap Events on Topaz 1261	CA-08-0001
Attachment 2	Liberty's Electric System Reliability Annual Report 2020	CA-08-0003
Attachment 3	Liberty CalPeco's Amended Response to DR CalAdvocates-LIB-A2506017-018	CA-08-0057
Attachment 4	PacifiCorp's Public Safety Power Shutoff History Commission Dashboard	CA-08-0064
Attachment 5	PacifiCorp's Annual California Electric Reliability Report Calendar Year 2021 Review	CA-08-0068
Attachment 6	Liberty's Electric System Reliability Annual Report 2019	CA-08-0131
Attachment 7	Liberty's Overhead Stringing and Sagging Standards in effect as of November 17, 2020	CA-08-0182
Attachment 8	Google Maps View of East and West Pole Locations	CA-08-0210
Attachment 9	Commission's Safety and Enforcement Division's 2012 Audit of Liberty Utilities	CA-08-0212
Attachment 10	Liberty CalPeco's Response to DR CalAdvocates-LIB-A2506017-019	CA-08-0236
Attachment 11 (Confidential)	Liberty's Response to CalAdvocates-LIB-A2506017-019, attachment "CONFIDENTIAL-Pole 266731 Loading Calculations." CONFIDENTIAL	CA-08-0243
Attachment 12	Priority Wire & Cable Inc., *Aluminum Conductor Steel Reinforced Specifications*, Accessed December 5, 2025	CA-08-0255
Attachment 13	Liberty CalPeco's Response to DR CalAdvocates-LIB-A2506017-036	CA-08-0259

ATTACHMENT 1

Liberty's 2020 WMP Attachment 5
Section 4.1 Wire Slap Events on Topaz 1261

Identifying Information	tion Informa	U

ID	Type of event	Date	Time	Circuit name	Voltage	Age of involved equipment
523	Wire slap	2015-07-01	18:00:00	1261	12.47kV	
570	Wire slap	2015-10-02	11:30:00	1261	12.47kV	
618	Wire slap	2016-01-29	15:00:00	1261	12.47kV	
650	Wire slap	2016-04-14	04:36:00	1261	12.47kV	
712	Wire slap	2016-10-14	07:31:00	1261	12.47kV	
697	Wire slap	2016-10-15	12:43:00	1261	12.47kV	
698	Wire slap	2016-10-16	00:51:00	1261	12.47kV	
719	Wire slap	2016-11-19	08:22:00	1261	12.47kV	
732	Wire slap	2016-11-27	06:52:00	1261	12.47kV	
749	Wire slap	2016-12-15	06:46:00	1261	12.47kV	
1039	Wire slap	2017-04-12	22:42:00	1261	12.47kV	
17187	Wire slap	10/20/17 0:00	0:00:00	1261	12.47kV	
17921	Wire slap	1/24/18 0:00	16:01:00	1261	12.47kV	
18087	Wire slap	2/22/18 0:00	6:39:00	1261	12.47kV	
19501	Wire slap	5/30/18 0:00	16:10:00	1261	12.47kV	
21408	Wire slap	1/17/19 0:00	9:29:00	1261	12.47kV	
22711	Wire slap	2/25/19 0:00	23:45:00	1261	12.47kV	
24279	Wire slap	9/16/19 0:00	18:03:00	1261	12.47kV	

ATTACHMENT 2

Liberty's Electric System Reliability Annual Report 2020

ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2020

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15, 2021

CA-08-0004

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2020 has been prepared in response to CPUC Decision 16-01-008, which established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC ("Liberty").

Liberty does not provide transmission services and does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for distribution services only. All statistics and calculations include forced distribution outages. Forced distribution outages are those that are not pre-arranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

Outages are tracked/recorded using the Responder OMS system and supplemented with dispatch emails when an incident is not logged. Dispatch is notified of outages from customer calls, device alarms, line crew, or another third party. An incident ID# is created and a troubleman will go investigate the nature of the incident. If it is a customer issue, the customer is told to contact an electrician. If the incident is an outage, efforts are made to restore customers in a timely manner. Once restored the incident ID is closed with the time of restoration and saved in Responder Archive.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.

2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.

3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.

4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

Liberty presents ten years (2011- 2020) of data, which represents the period in which Liberty Utilities has owned the utility.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days ("MED") instead of CPUC Major Events. An IEEE MED is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as "TMED". Thus, any day in which the total system SAIDI exceeds TMED is excluded from Liberty's reliability results. The applicable TMED value is calculated at the end of each year using Liberty's daily SAIDI values for the prior five years. Liberty's TMED value for 2020 was 189.04 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

Table of Contents

1) System Indices for the Last 10 Years

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

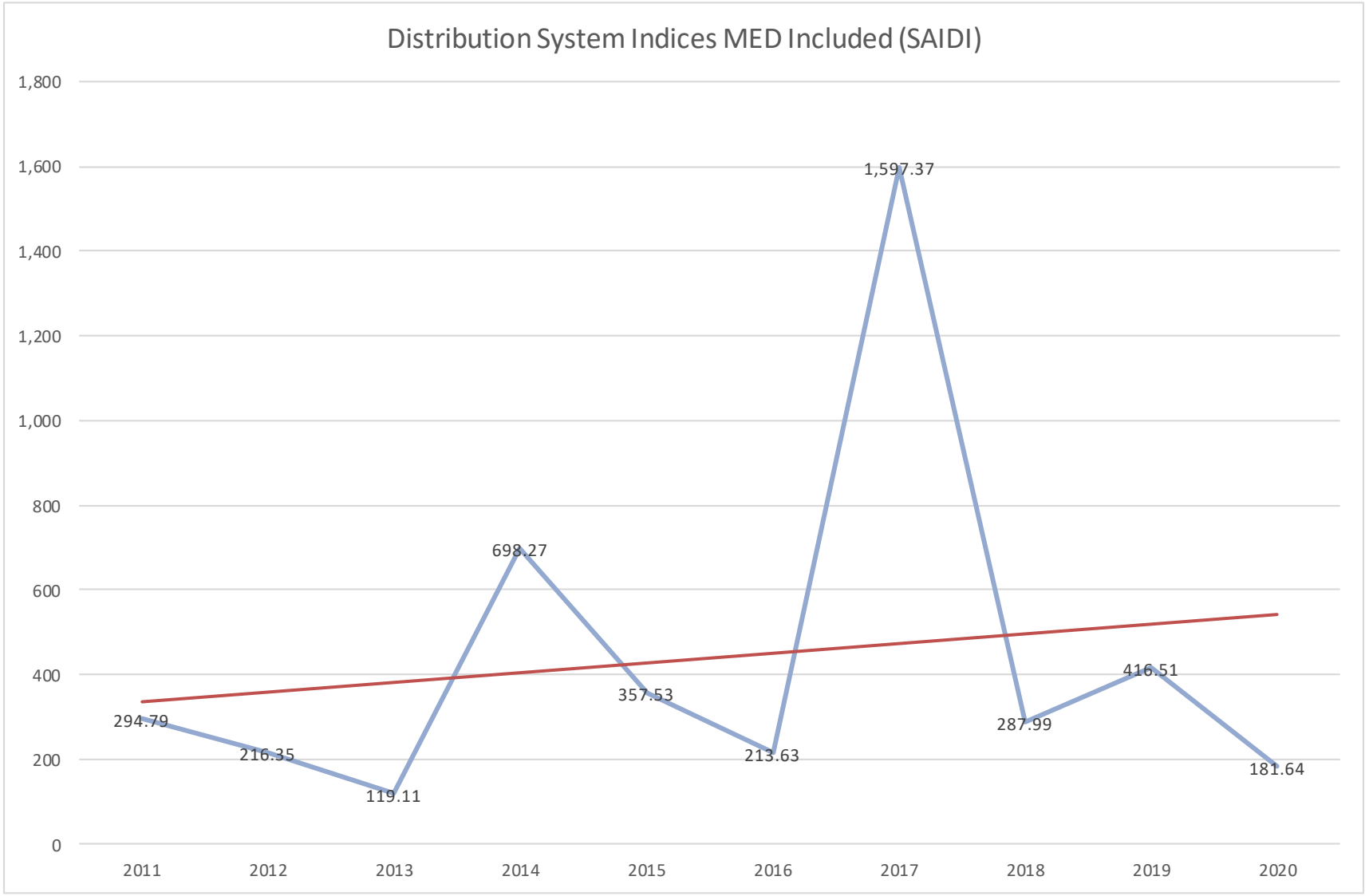
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 10 Years (Years in Business)

	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1,597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

II. Transmission System Indices (MED Included and Excluded)

Liberty does not own Transmission.

b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years (years in business) with linear trend line (TMED included and excluded).


Distribution System Indices MED Included (SAIDI)
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1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
181.64
2011
2012
2013
2014
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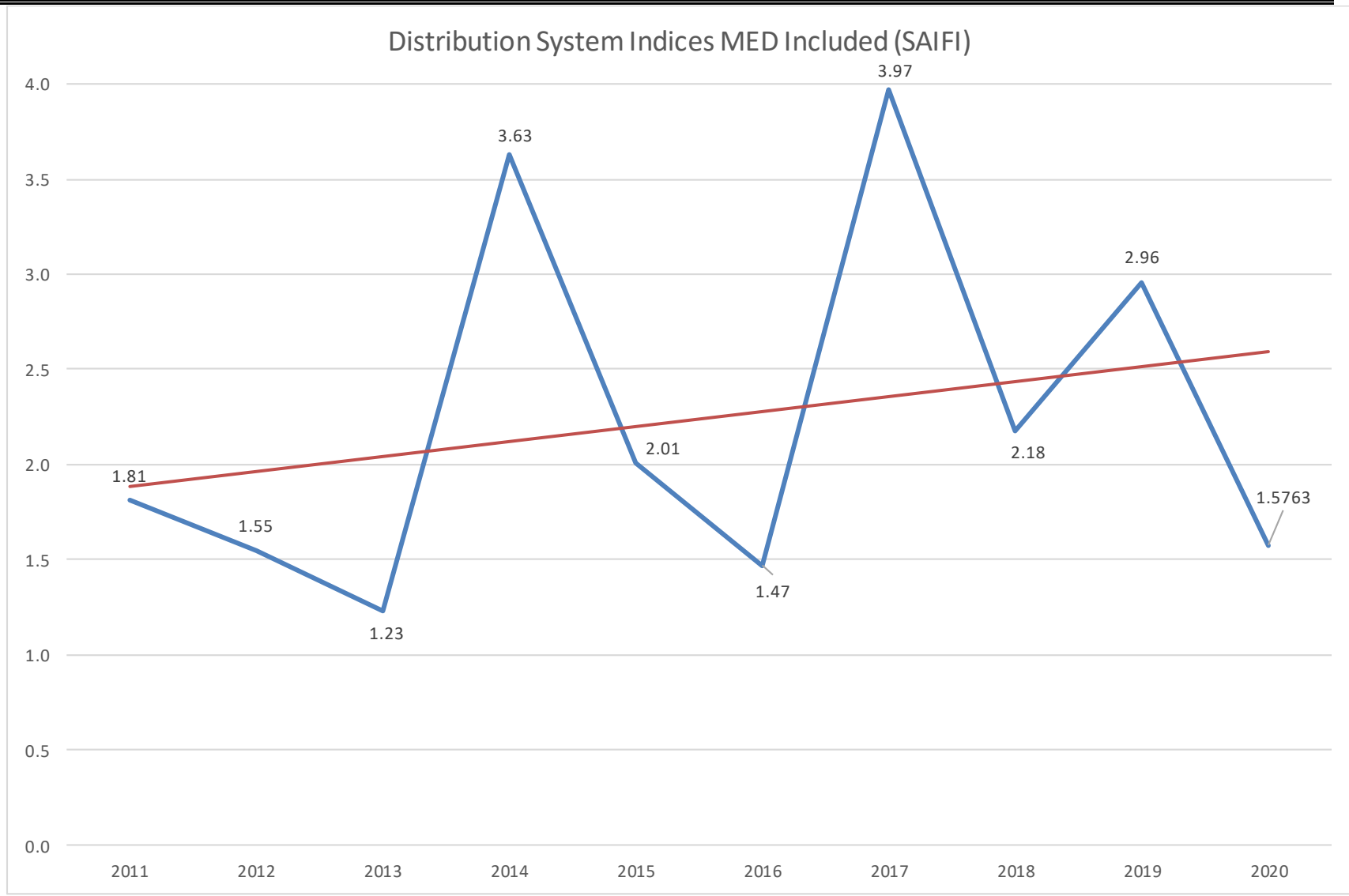
2017
2018
2019
2020


Distribution System Indices MED Included (SAIFI)
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3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
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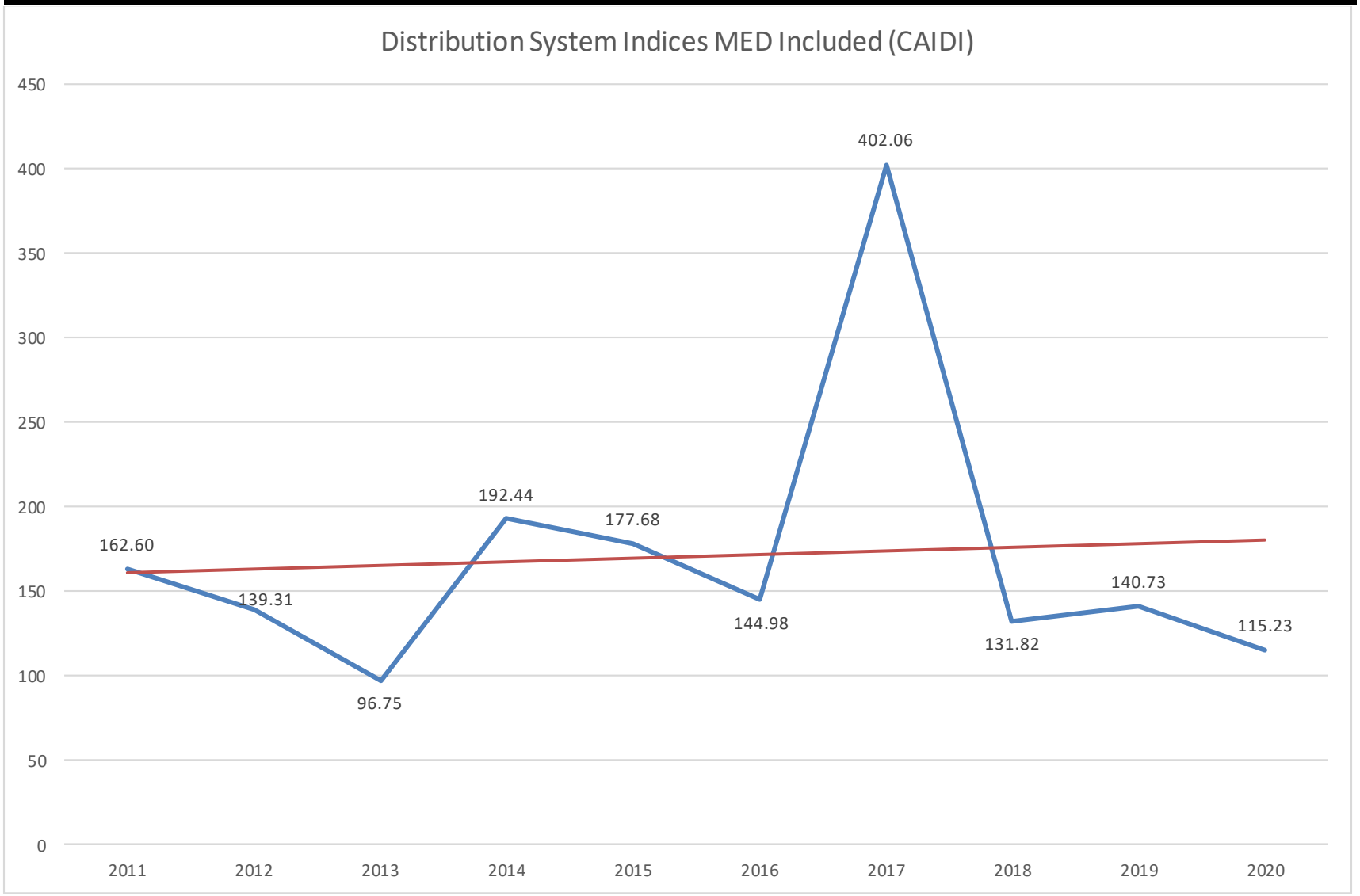
3.97
2.18
2.96
1.5763
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020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400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
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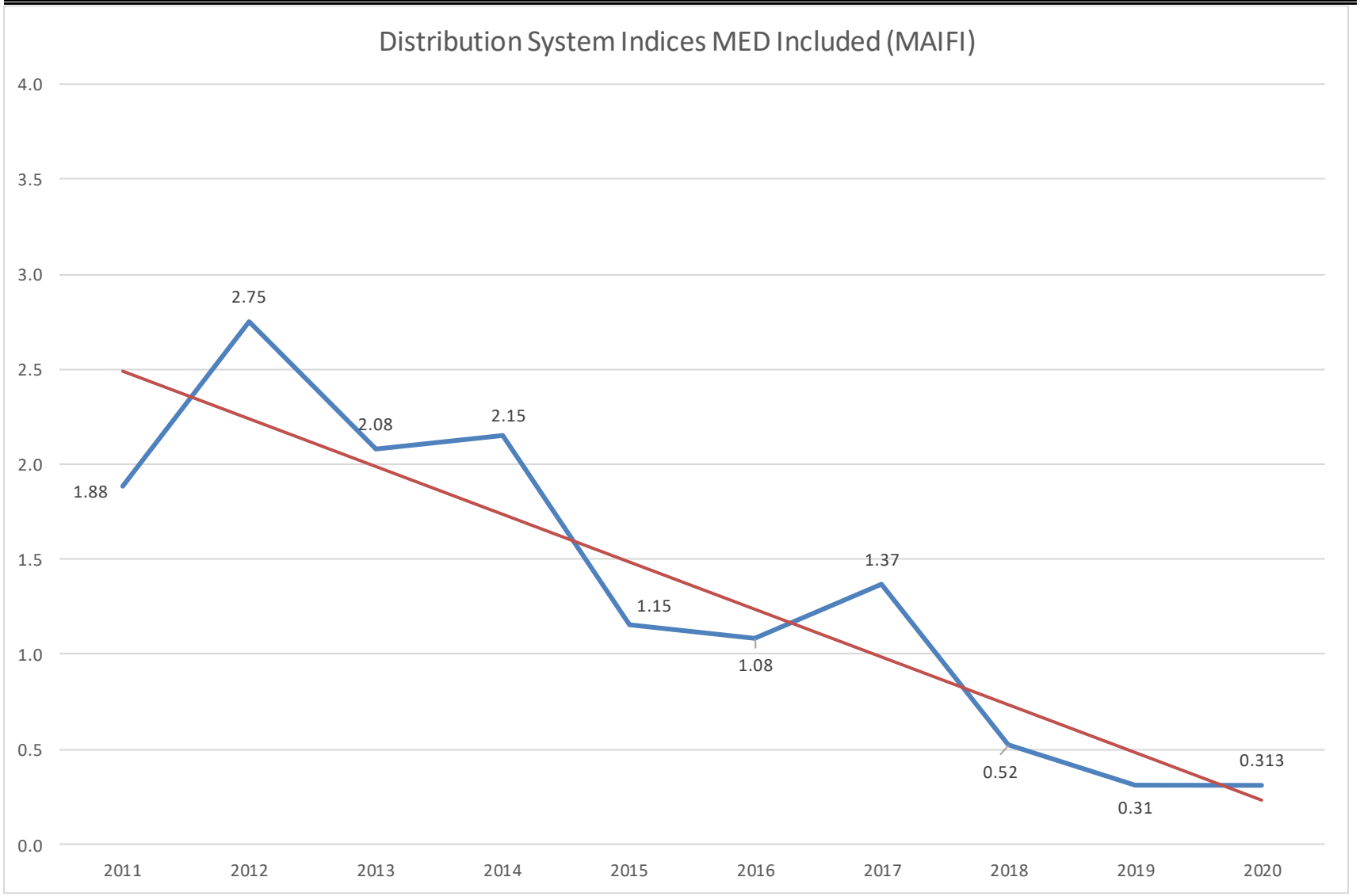
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Included (MAIFI)
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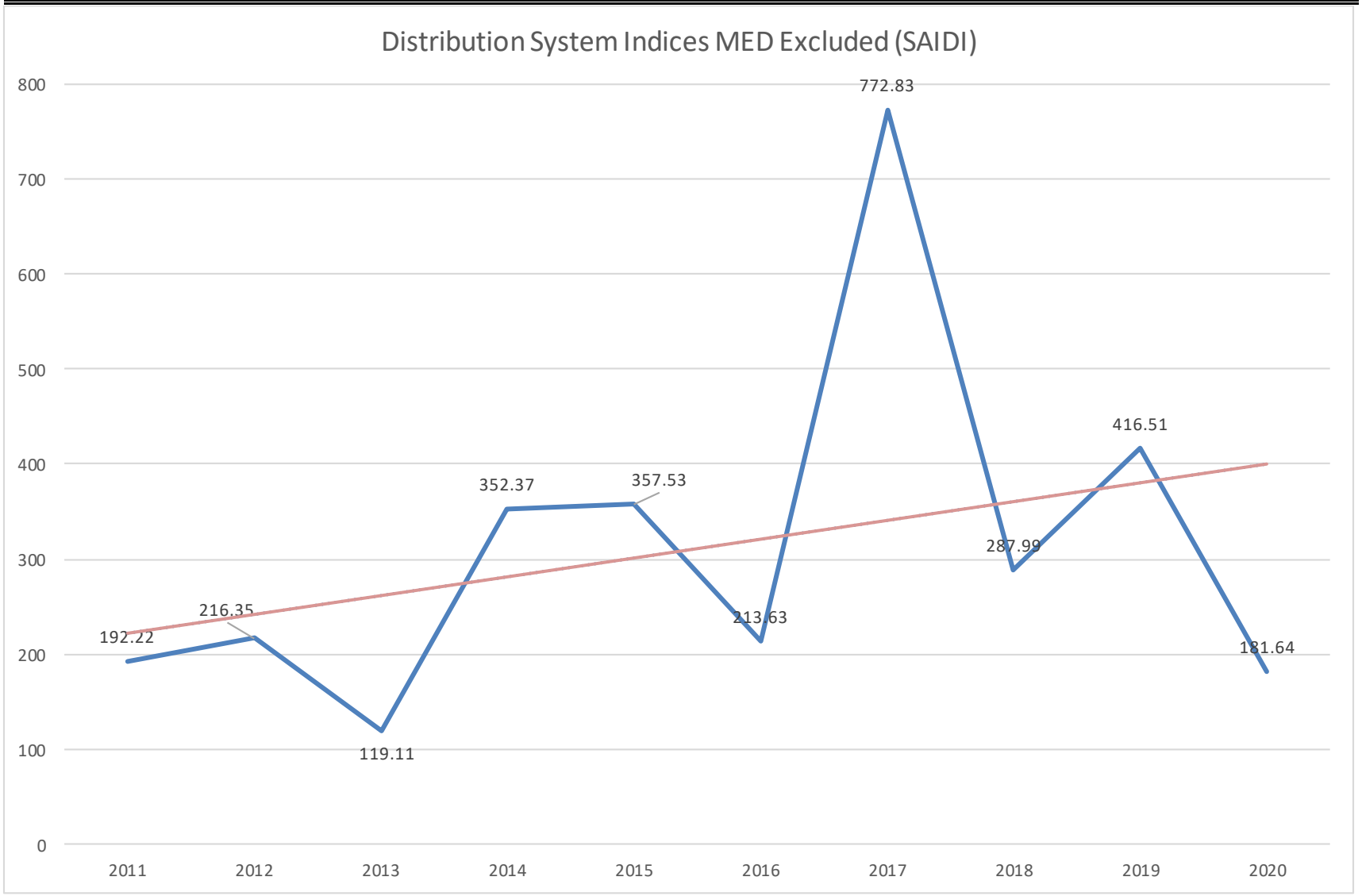
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.15
1.08
1.37
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (SAIDI)
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700
600
500
400
300
200
100
0
192.22
216.35
119.11
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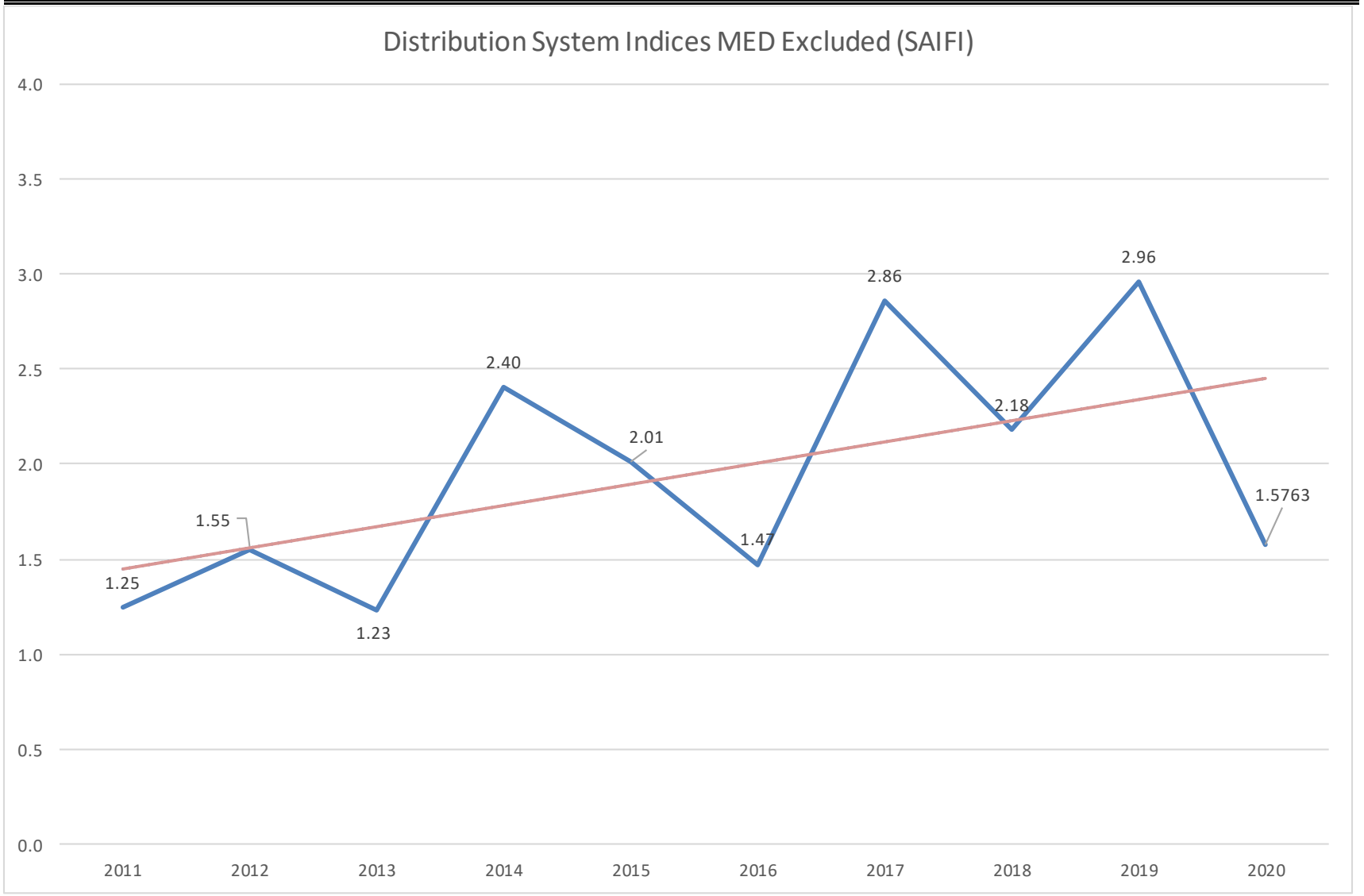
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (SAIFI)
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3.5
3.0
2.5
2.0
1.5
1.0
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0.0
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1.55
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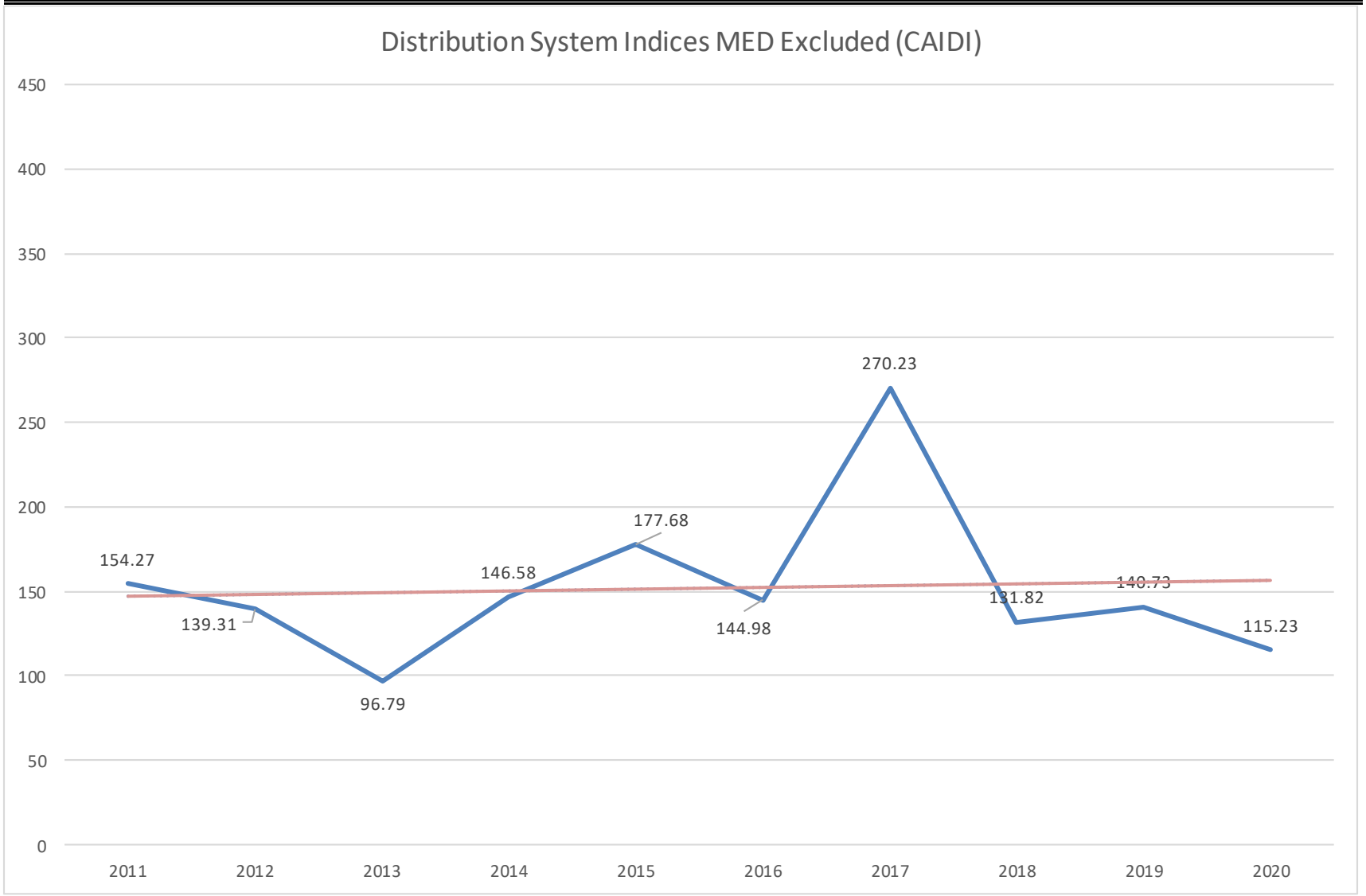
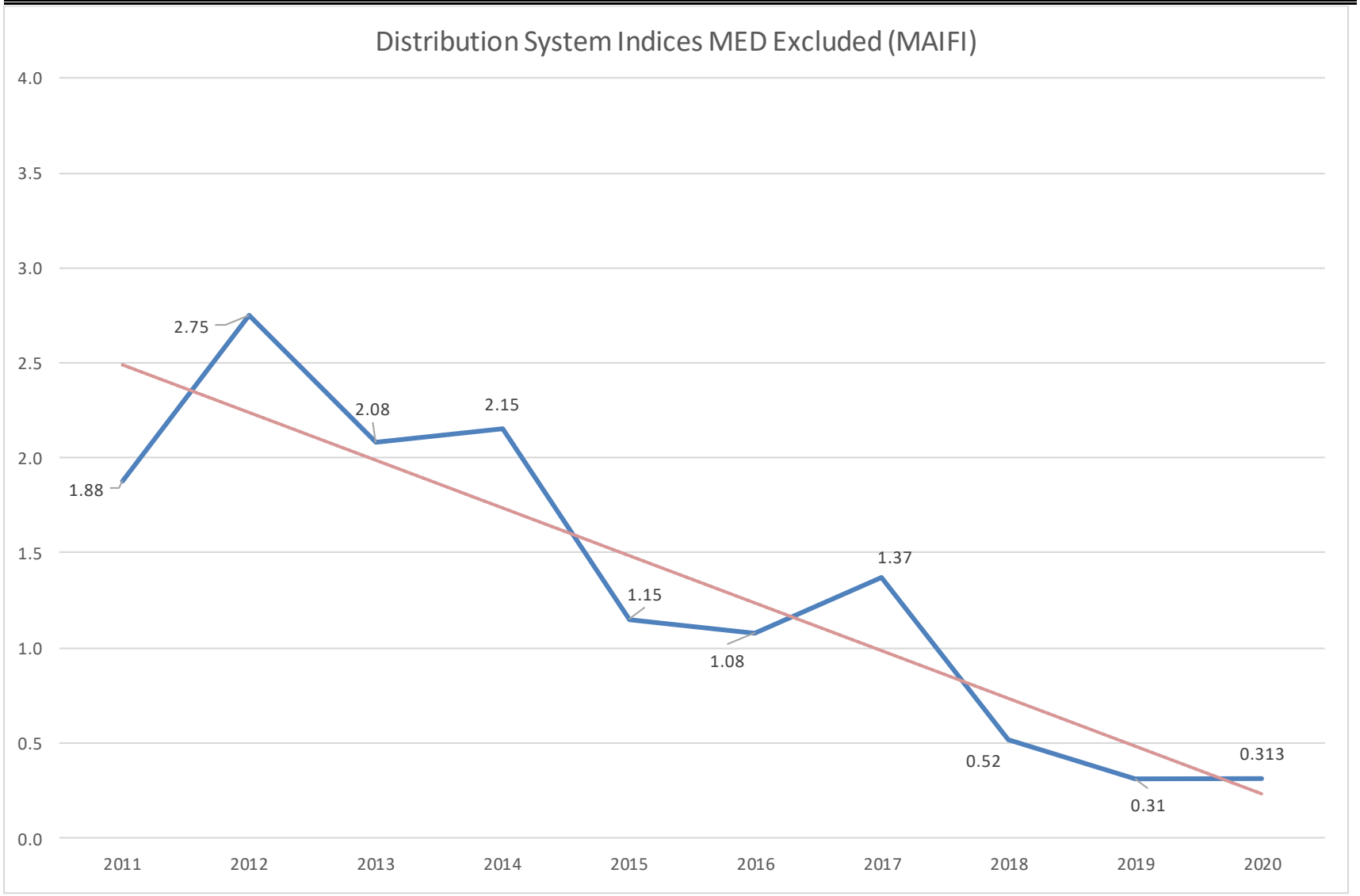
2.40
2.01
1.47
2.86
2.18
2.96
1.5763
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
270.23
131.82
140.73
115.23
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

2) Division (or District) Reliability Indices for the past 10 years

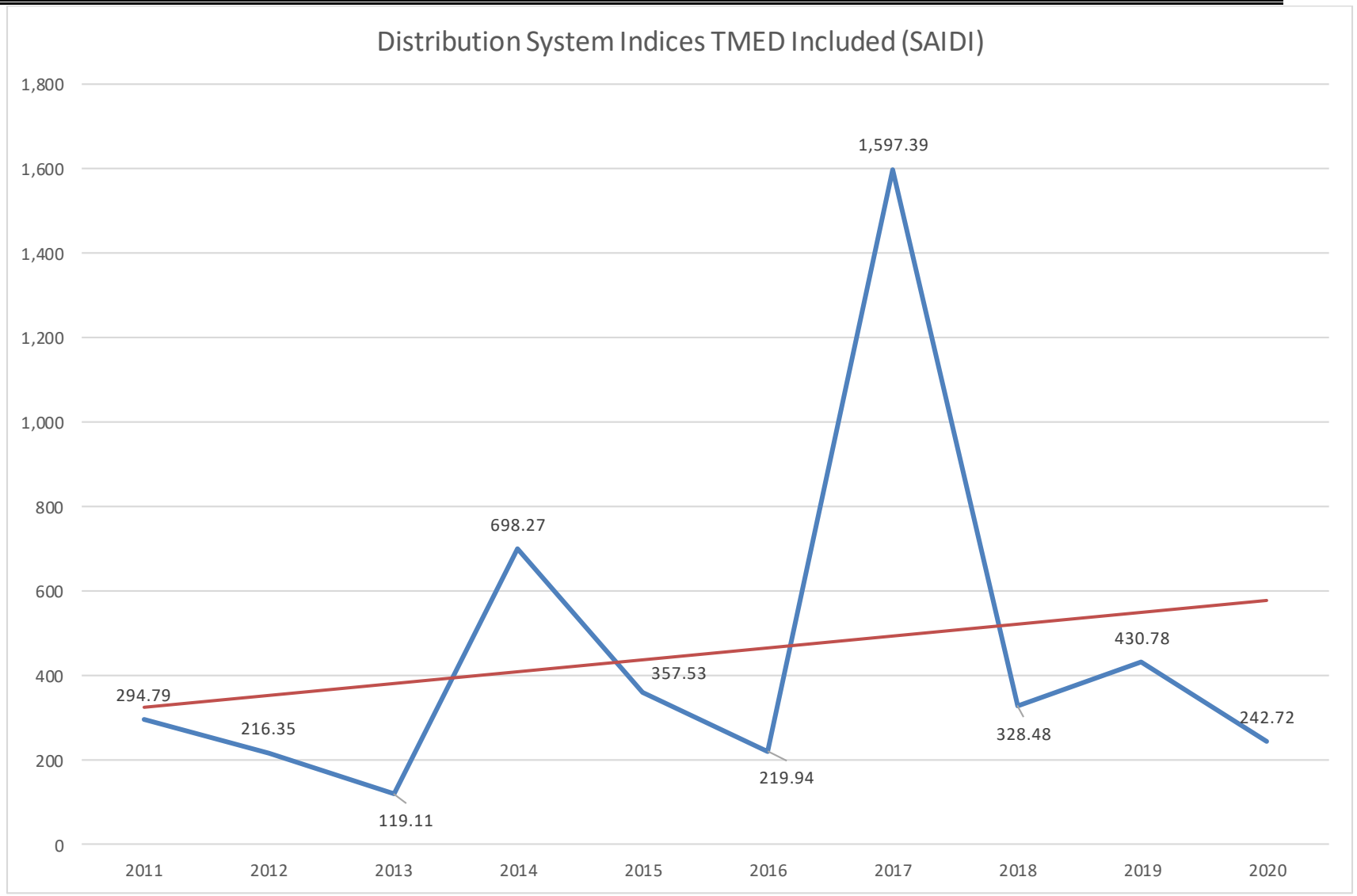
Liberty has one division, Lake Tahoe. See section 1 for indices.

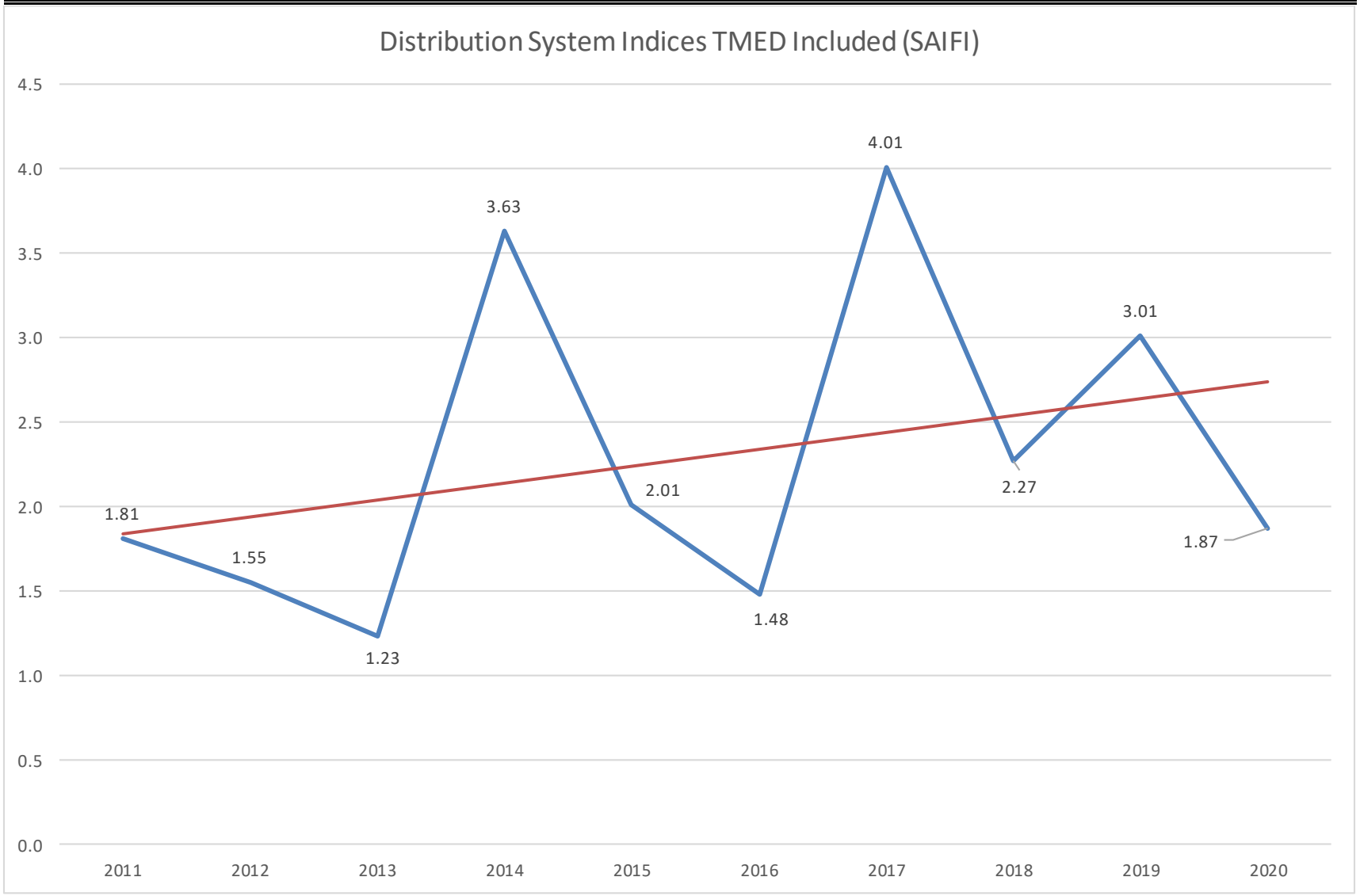
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding TMED

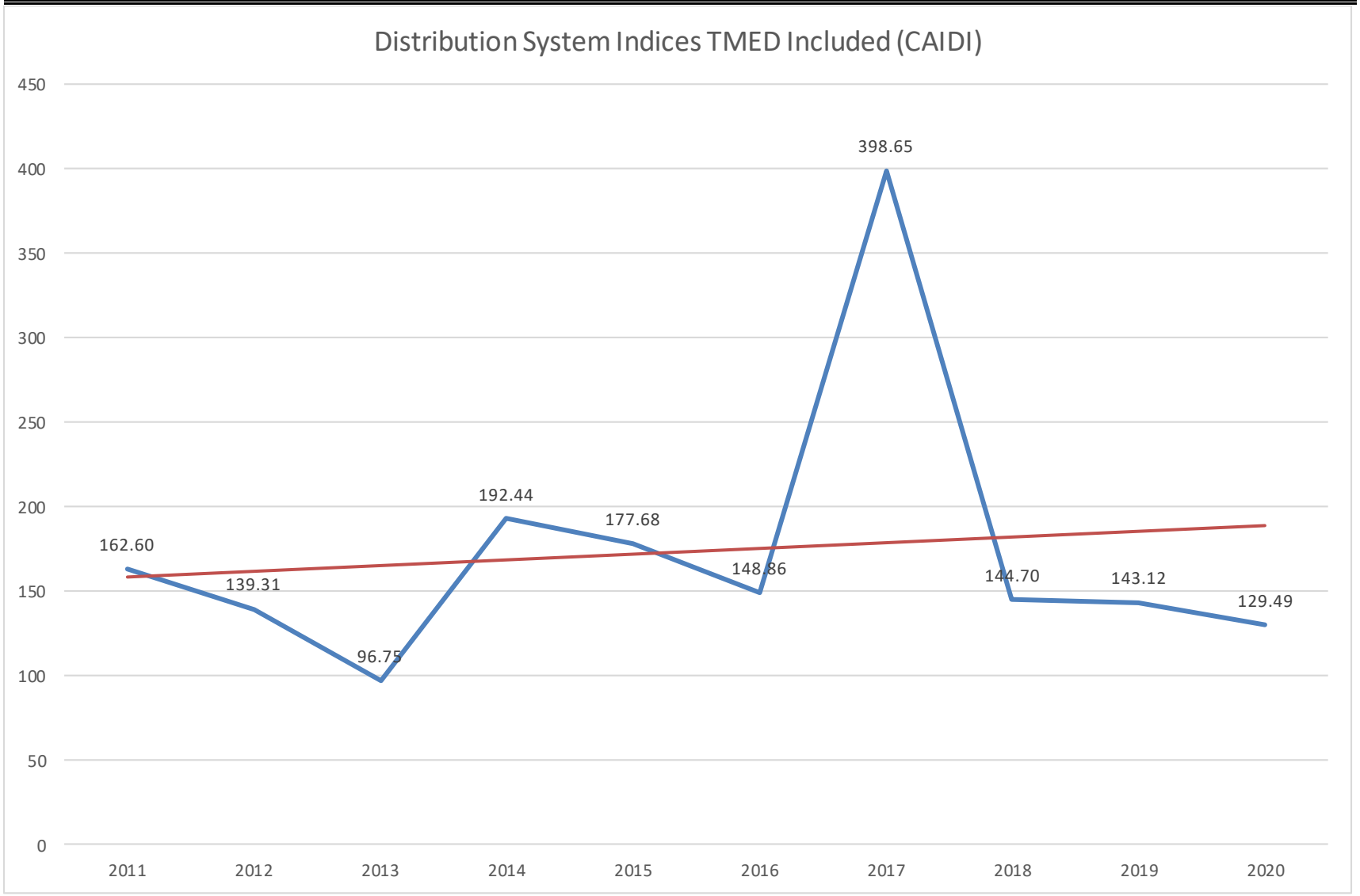
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

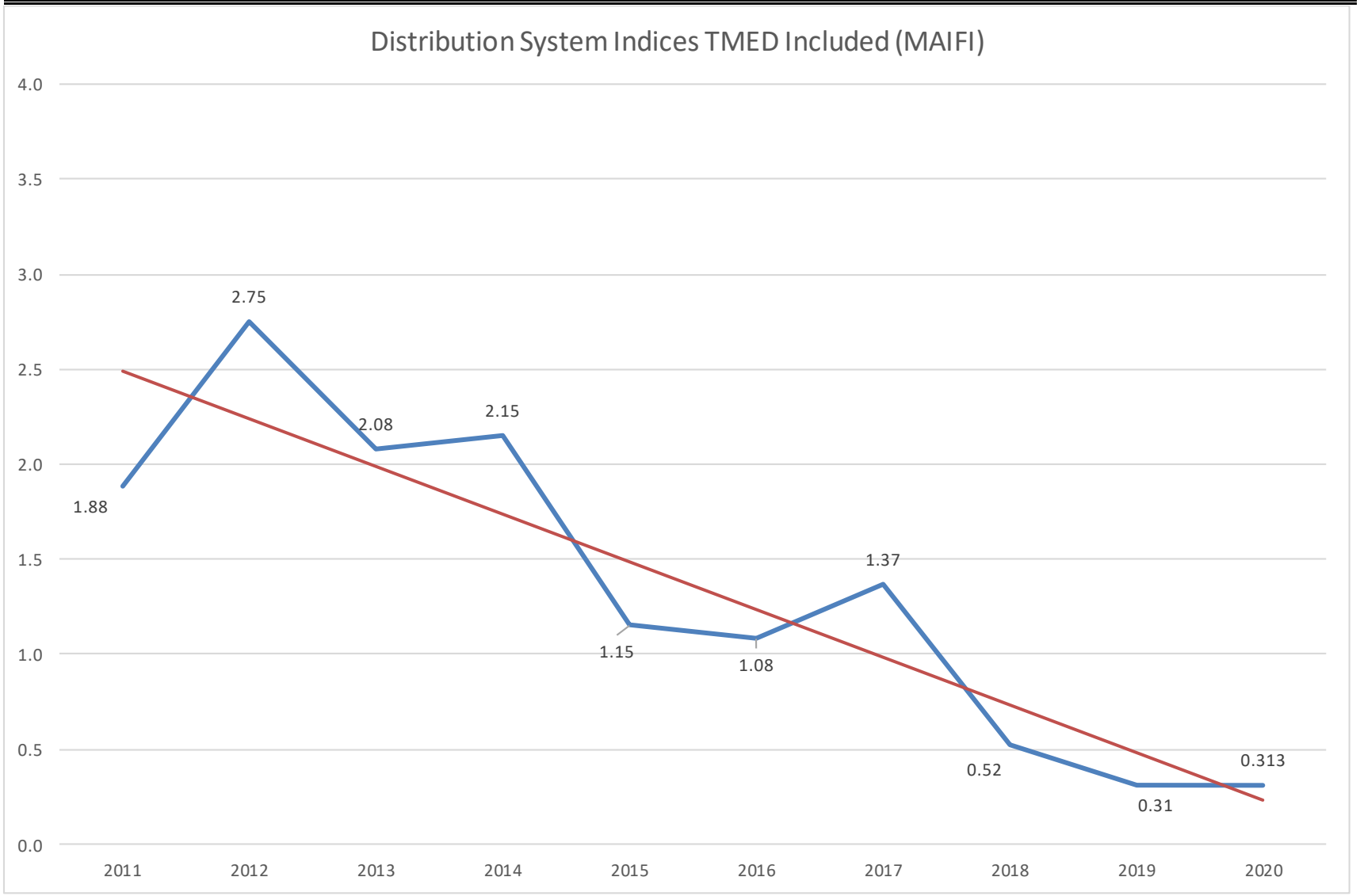
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 10 Years (Years in Business)

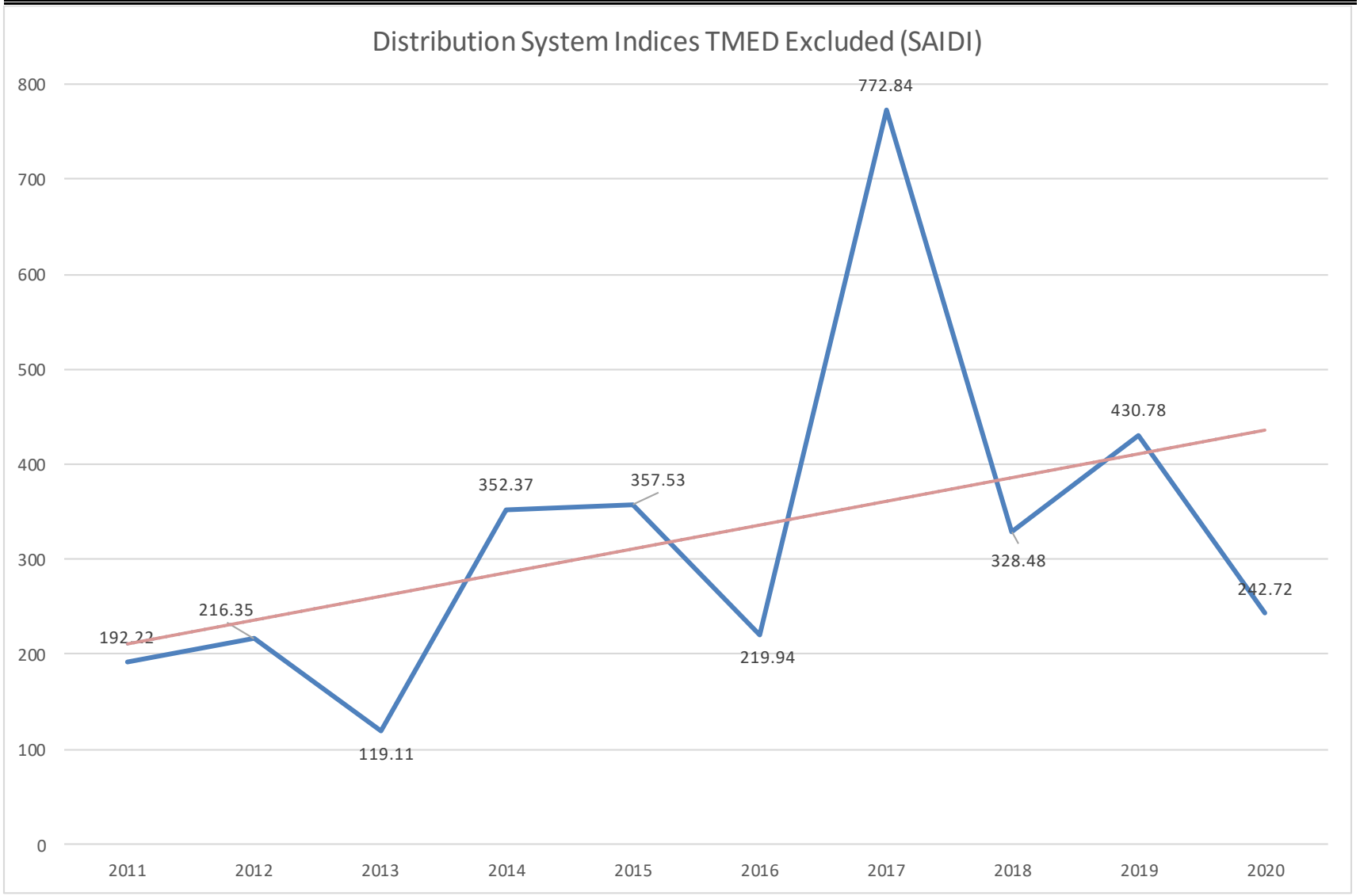
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.70	0.52	328.48	2.27	144.70	0.52
2017	1,597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

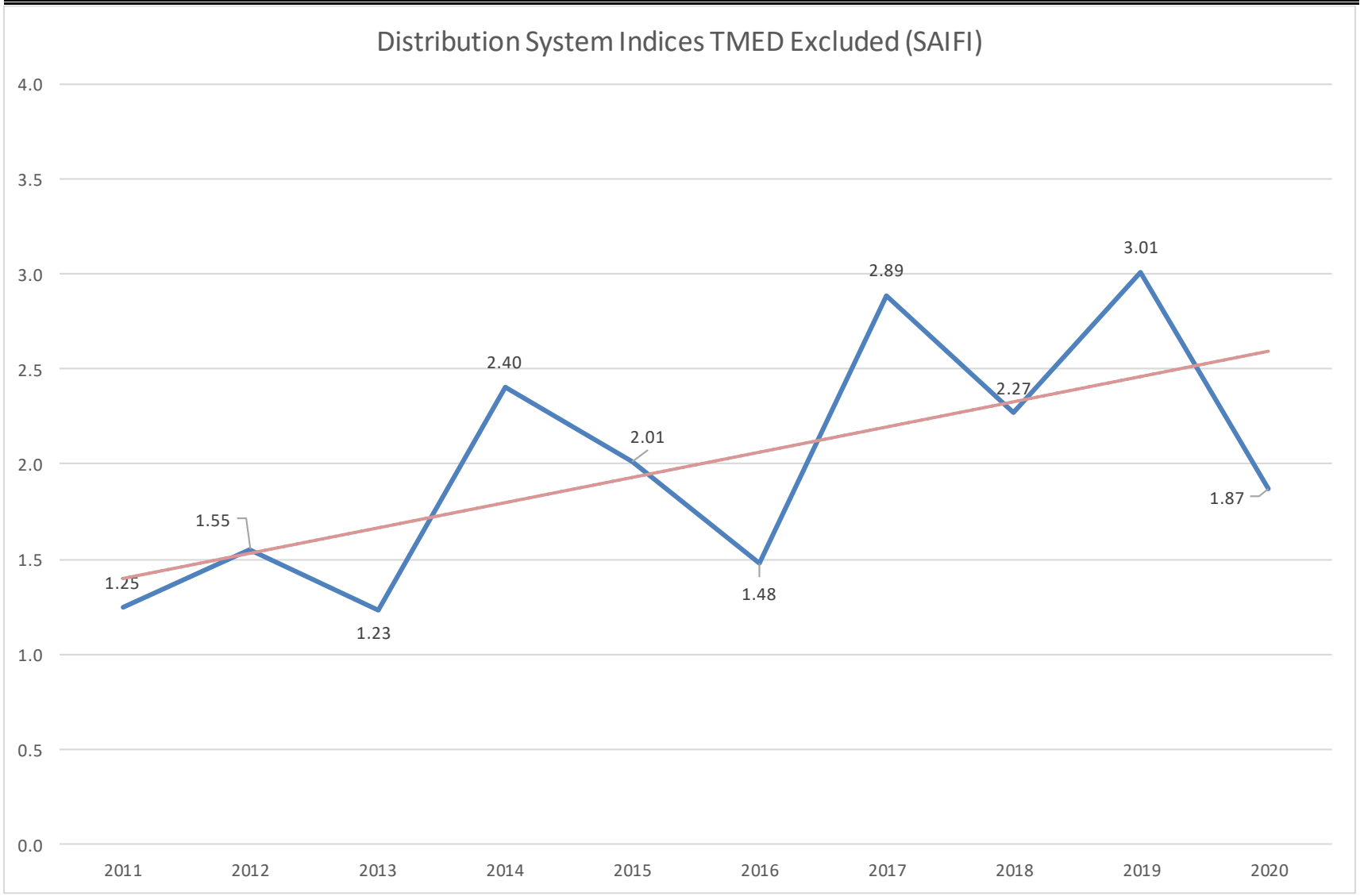

Distribution System Indices TMED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
242.72
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

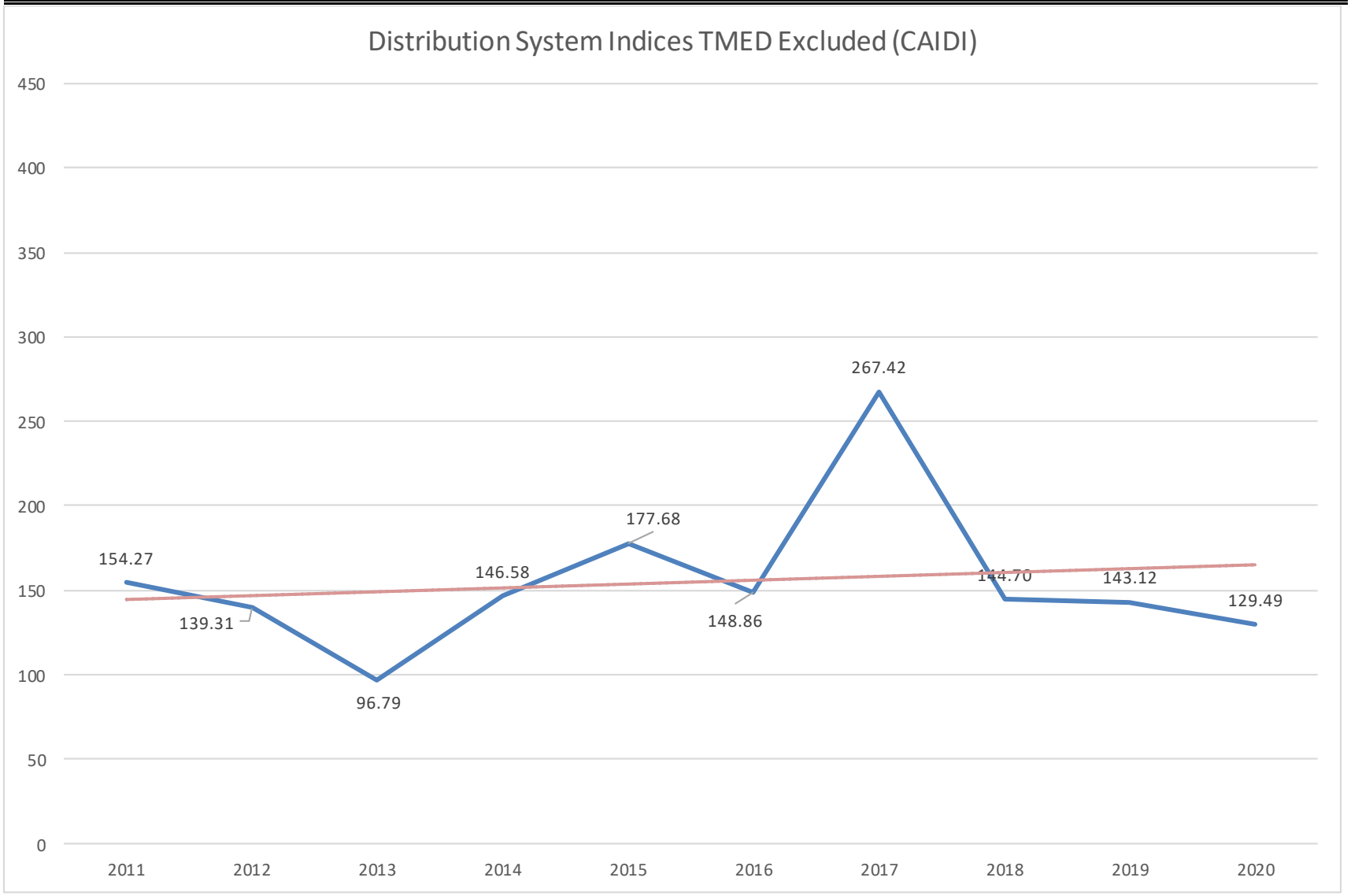

Distribution System Indices TMED Included (SAIFI)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.48
4.01
2.27
3.01
1.87
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

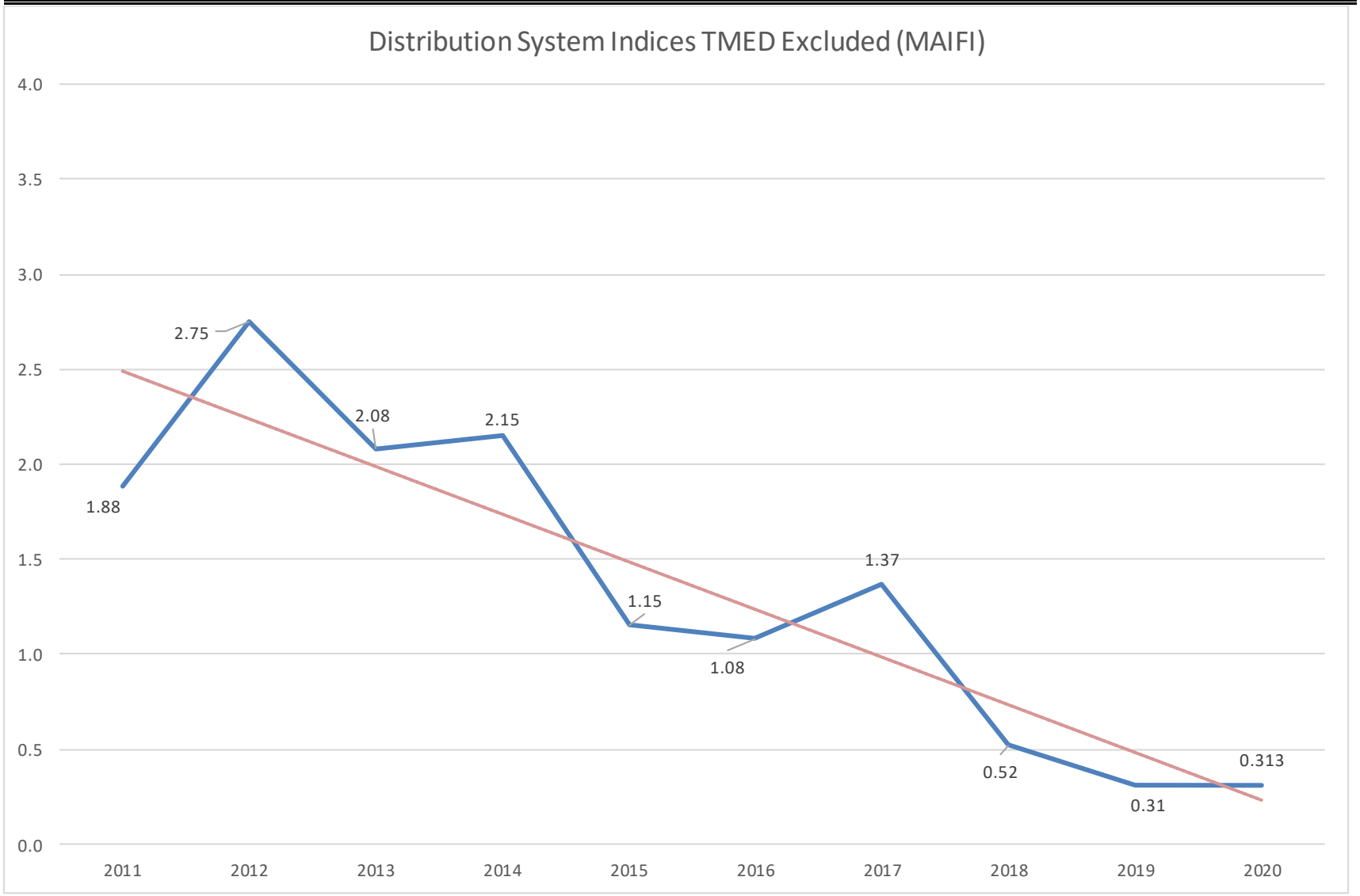

Distribution System Indices TMED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
398.65
144.70
143.12
129.49
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
219.94
772.84
328.48
430.78
242.72
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.48
2.89
2.27
3.01
1.87
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
267.42
144.70
143.12
129.49
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

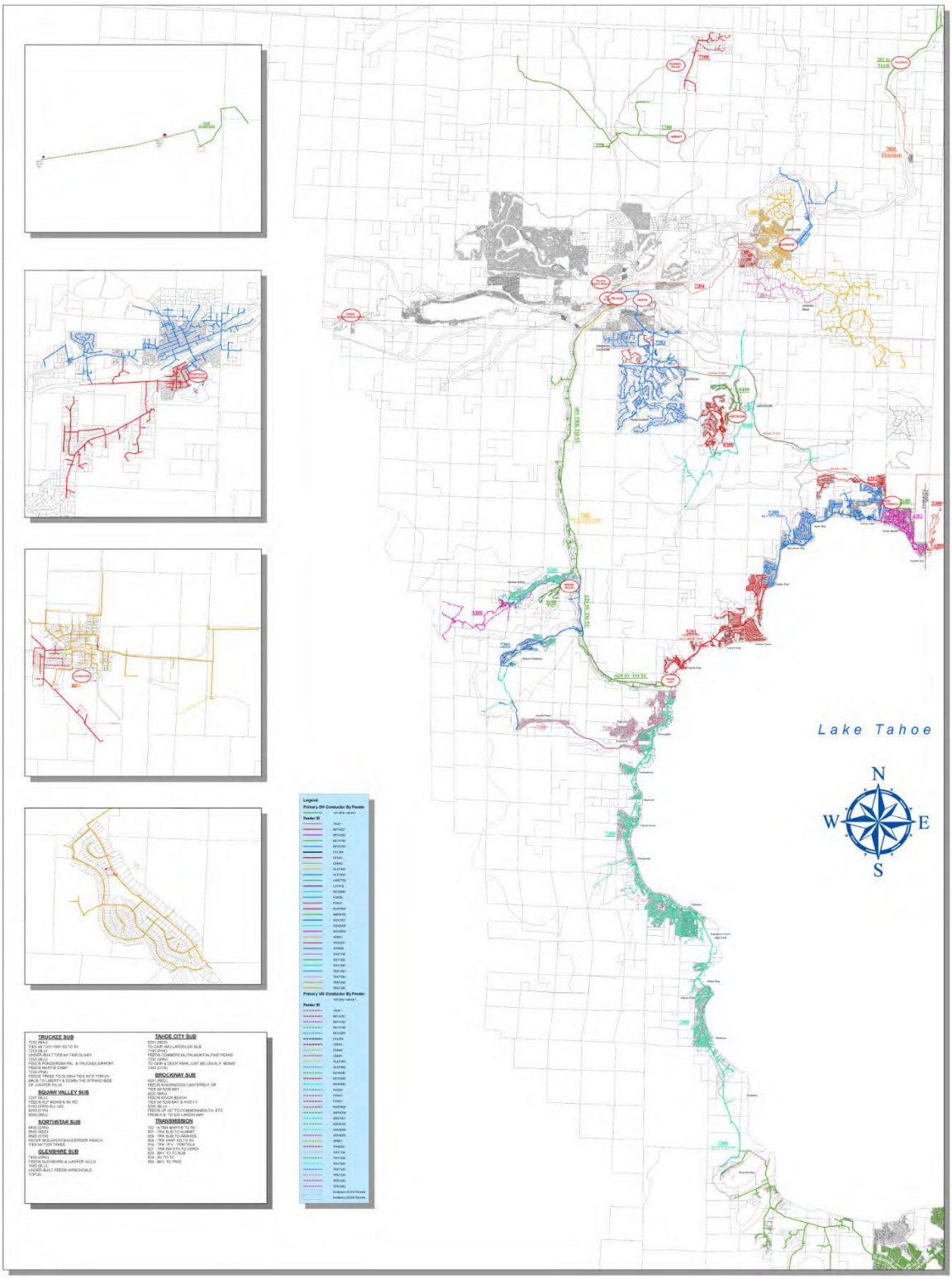

Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

b. The number, date, and location of planned outages

Circuit	Number of Planned Outages By Year									
	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011
31	3		1			1				
32	4	1		2	1					
41	6				1					
201			7					1		
204		2			1					
619									1	
650						1			1	
1261	7	1	1							
1296	2		1	2		5	1			
2200		1				1	1			
2300		1	1			1	2		1	
3100	2	8	5	1					1	1
3101	3	3					2	2		
3200	1	3	5			1			1	
3300	3	8	10	2		3			2	
3400	1	2	4	3		5		2	4	
3500	6	15		6		1				
3501		3	3			2	2	4	1	1
4201		1	1		1					
4202	2	5	3	4				2	5	1
5100	1							1	1	
5200	1	5	4	1		4	1	1	3	
5201		8	1	5	5	4	1		1	
7100	4	1	2	1			1	1	4	
7200		1	1			1	1	1	2	
7201	1	1		4	1	2	1			
7202	3	3	1	1		2	3	1		
7203		3	2			2	2	4		
7300	8	20	14	5	6	4	16	4	5	2
7400	1	4	8	2	1	1				1
7600		1	1			1				1
7700	4						1			
7800							2			
7900	2	1								

8200	1	1	2	7	3	2	4			1
8300	1	1	1	2		6			2	
8400	1		7							
8500	2				1			1	2	
8600						4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	749	Topaz	70.9	76.2%	23.8%	5	2615	5.66
31	Tahoe	671	Portola	15.5	88%	11.9%	2	594	2.82

Note: Preferred Metric is the average of circuit SAIDI over a three-year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2018, 2019 and 2020. The three-year average circuit SAIDI score remains high due to an operations error causing an outage on March 22, 2019 that lasted approximately 58 hours, and a fire that occurred on November 17, 2020 causing widespread outages over the circuit that were restored over the course of 12 hours.

There were 22 unplanned outages in 2020 for the 1261 circuit, two were due to weather conditions, three were due to device failure, one was due to fuse operation, six were due to the Coleville fire and the rest were unknown.

The historical metric for Topaz 1261:

- 2020 – 2,615.2
- 2019 – 3,040.6
- 2018 – 2,393.8
- 2017 – 3,004.5
- 2016 – 1,930.4

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2020 was higher than historical records. The events in 2019 and 2020 were outliers resulting from extreme weather

conditions and do not accurately represent the overall performance of the system.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top two Worst Performing Circuits ("WPC") are determined based on the calculated average of circuit SAIDI over a three-year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years of data are included and averaged to account for anomalies and track the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

Liberty's regional engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to Liberty's business manager, engineering manager, and vice president of operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	7/28/2020	Operations Error	Lake Tahoe	5,291	4.43	0.1081
2	8/24/2020	CB Lockout, Lightning possible	Lake Tahoe	3,835	7.68	0.0783
3	11/6/2020	Unknown	Lake Tahoe	3,728	5.94	0.0762
4	8/12/2020	Wind/Debris	Lake Tahoe	3,724	2.58	0.0761
5	9/10/2020	Animal	Lake Tahoe	3,451	1.27	0.0705
6	9/6/2020	Animal	Lake Tahoe	3,266	3.47	0.0667
7	10/23/2020	Animal	Lake Tahoe	3,266	1.13	0.0667
8	7/28/2020	Animal	Lake Tahoe	2,555	1.46	0.0522
9	7/2/2020	Device failure	Lake Tahoe	2,555	2.14	0.0522
10	7/28/2020	Operations Error	Lake Tahoe	2,555	1.38	0.0522

*Based on customer impact

7) Summary list of 2019 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2019 = 189.04

Liberty did not experience an event in 2020 where the daily SAIDI was higher than the calculated TMED.

8) Historical 10 largest unplanned outage events for the past 8 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3,597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6,251.1	No
3	Unknown	11/6/2020	3,728	1.30	4,846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2,085.44	No
5	Animal	9/10/2020	3,451	0.30	1,035.3	No
6	Animal	9/6/2020	3,266	0.86	2,808.7	No
7	Animal	10/23/2020	3,266	0.28	914.5	No
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3,653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1,737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40,701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37,835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1,411.4	No
4	Hardware Failure	2/26/2019	4,485	3.50	15,697.5	No

5	Tree	1/18/2019	4,448	1.76	7,828.5	No
6	Hardware Failure	3/6/2019	4,448	0.82	3,647.4	No
7	Animal	11/11/2019	4,245	0.60	2,547.0	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1,596.2	No
9	Animal	6/7/2019	3,529	0.47	1,658.6	No
10	Tree	6/7/2019	3,507	1.51	5,295.6	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91,301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14,218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6,958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6,420.1	No
7	Unknown	11/12/2018	4,154	1.76	7,338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8,072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	215,600	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.40	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.8	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.0	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.3	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.8	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.9	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.0	No
7	Trees	3/1/2016	3,258	0.50	1,683.3	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.1	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.3	No
10	Trees	6/15/2016	2,732	8.15	3,822.7	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	0.67	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

9) Number of customer inquiries on reliability data and the number of days per response

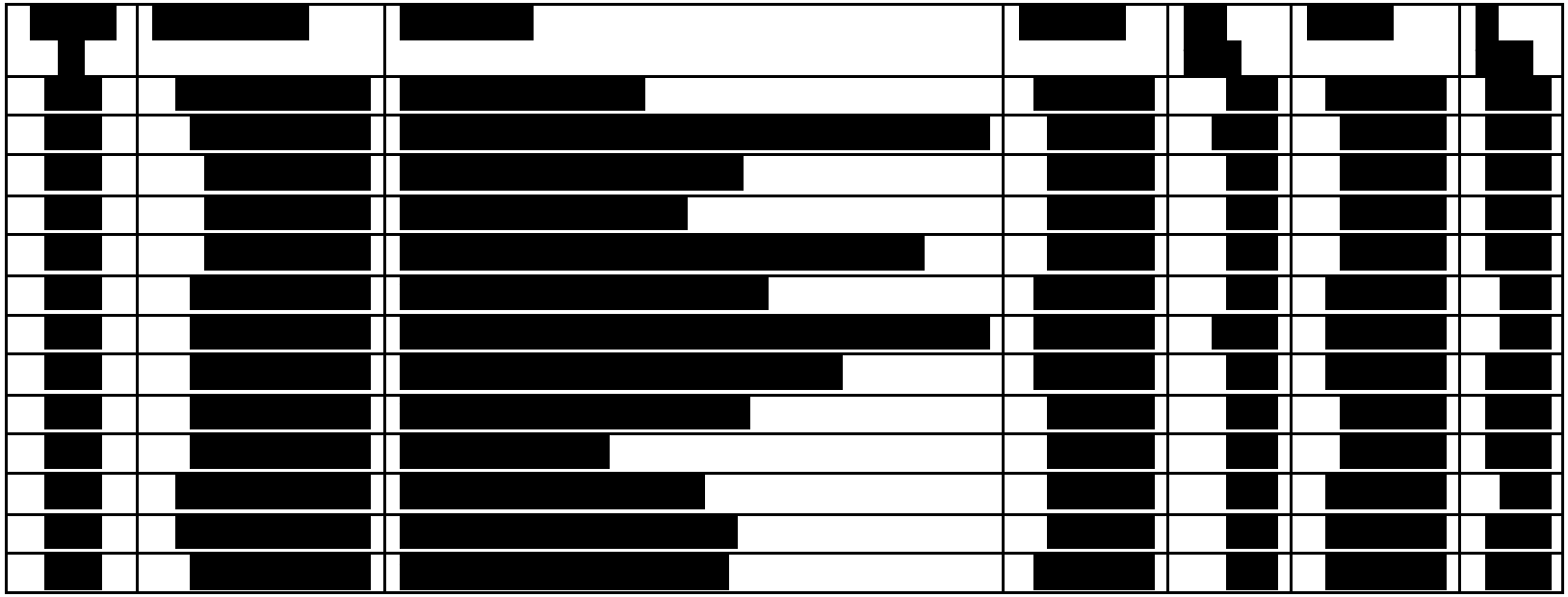
Liberty did not receive any customer inquiries on reliability data in 2020.

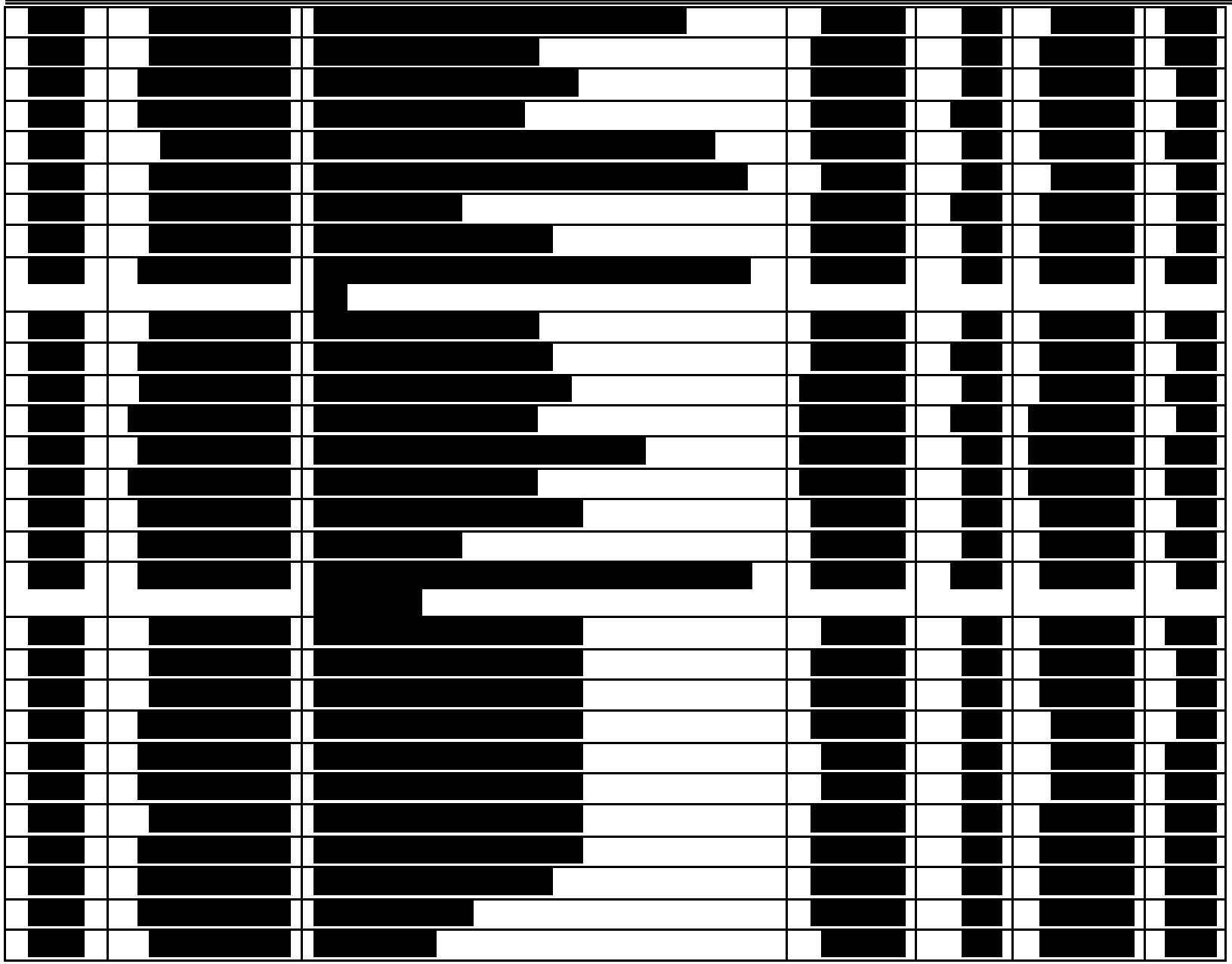
Date Received	Date Responded	Description of Inquiry

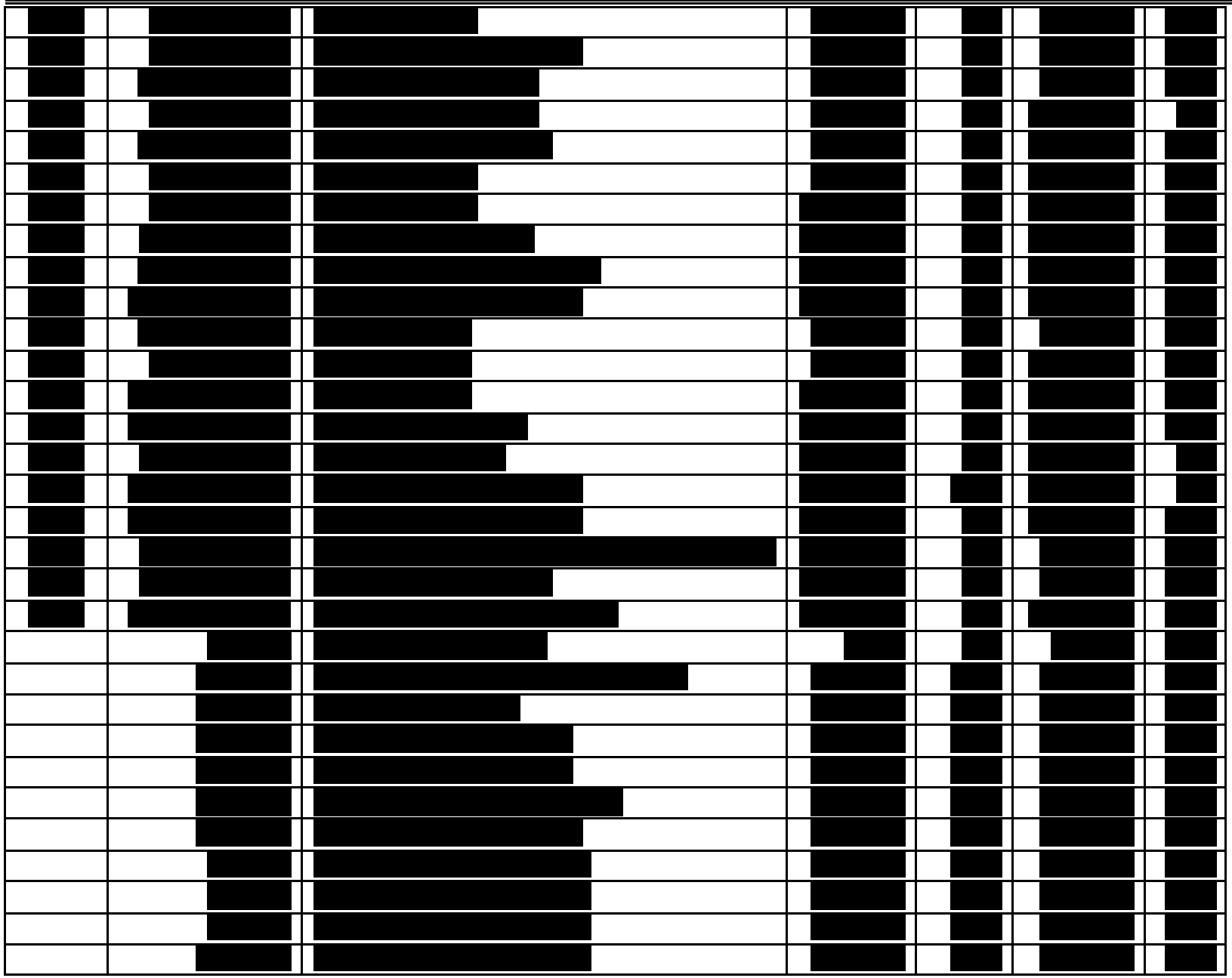
10) List of PSPS's in 2020

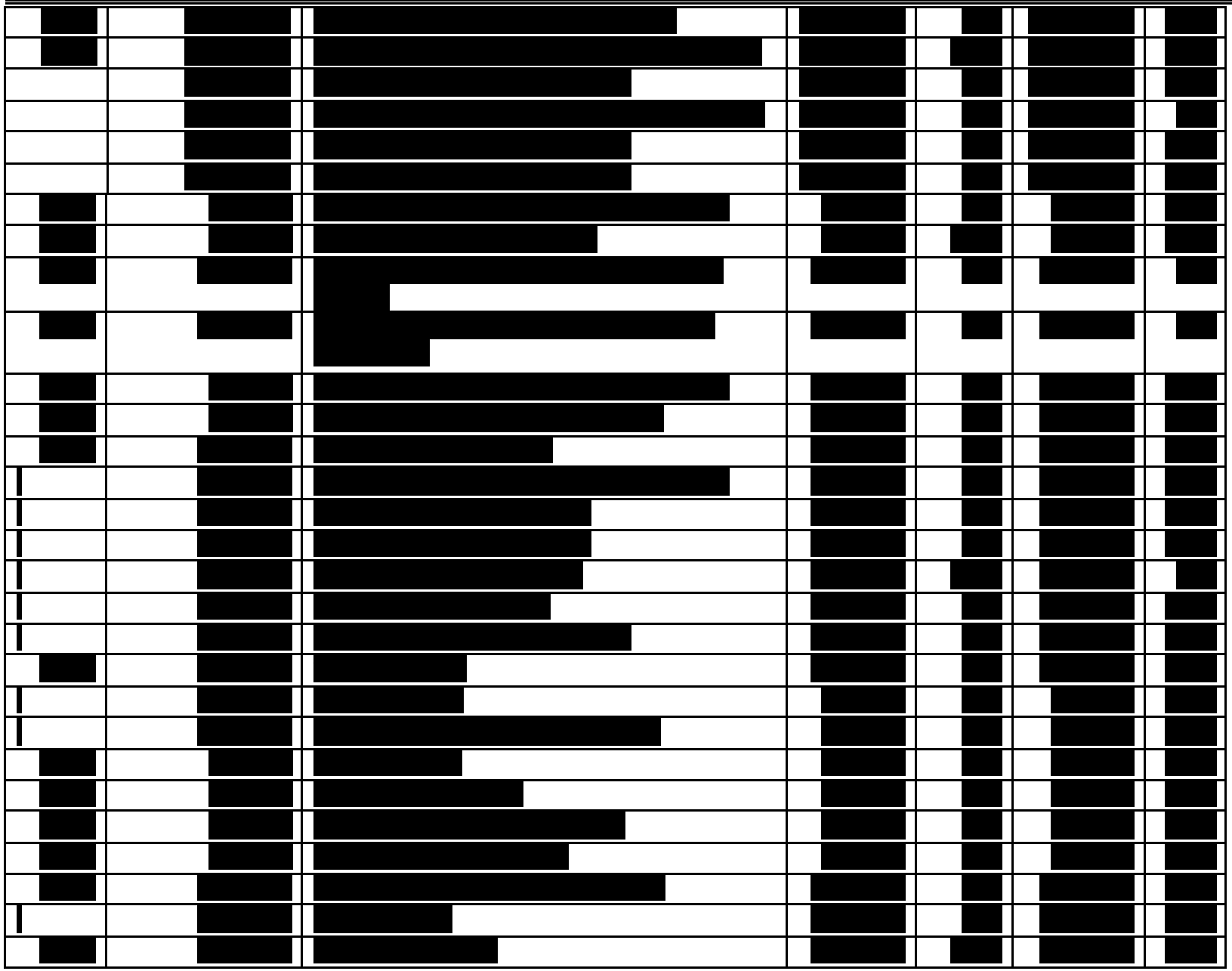
Liberty did not have any PSPS events in 2020.

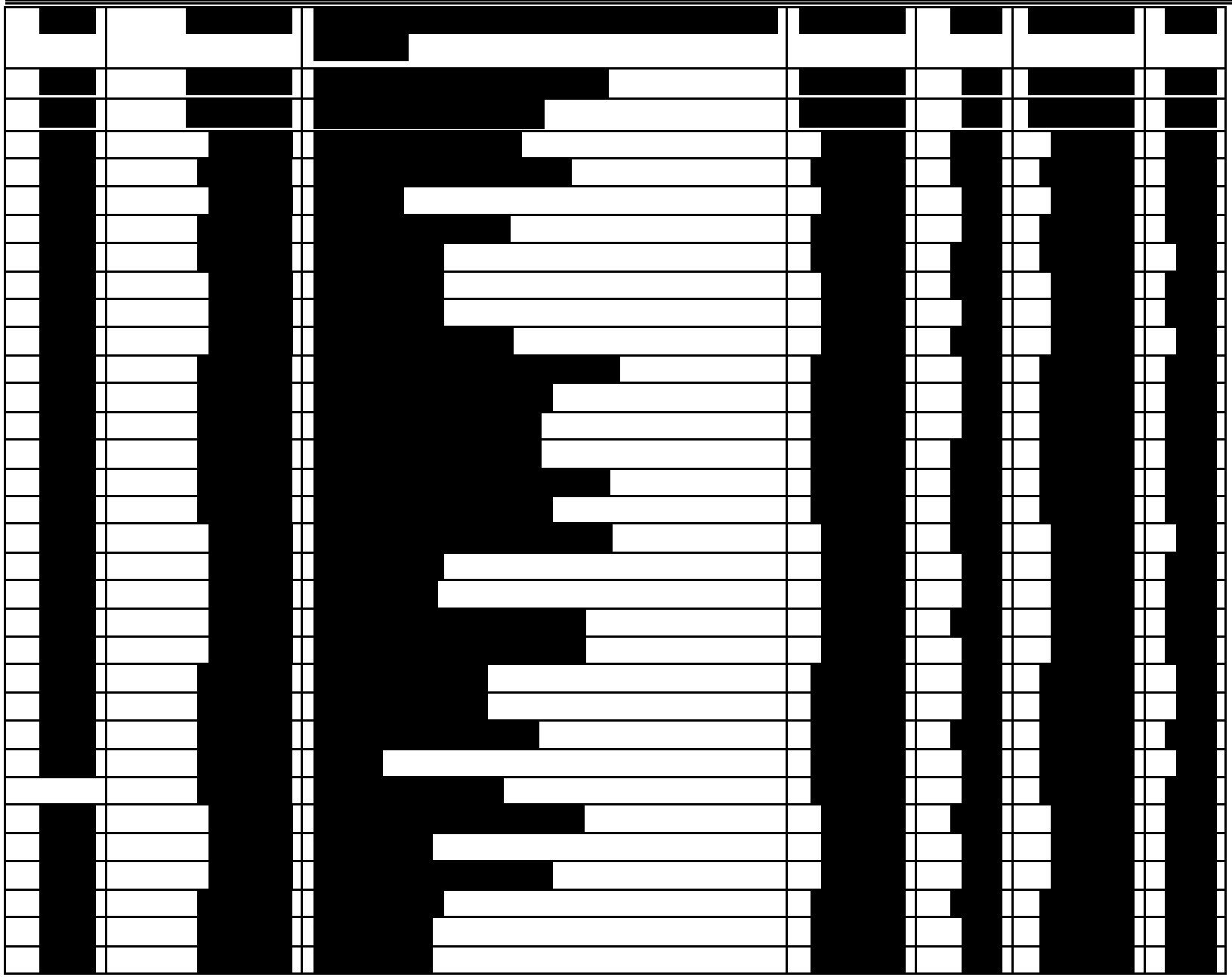
Appendix A: 9 Years of Planned Outage Data -- PUBLIC VERSION --

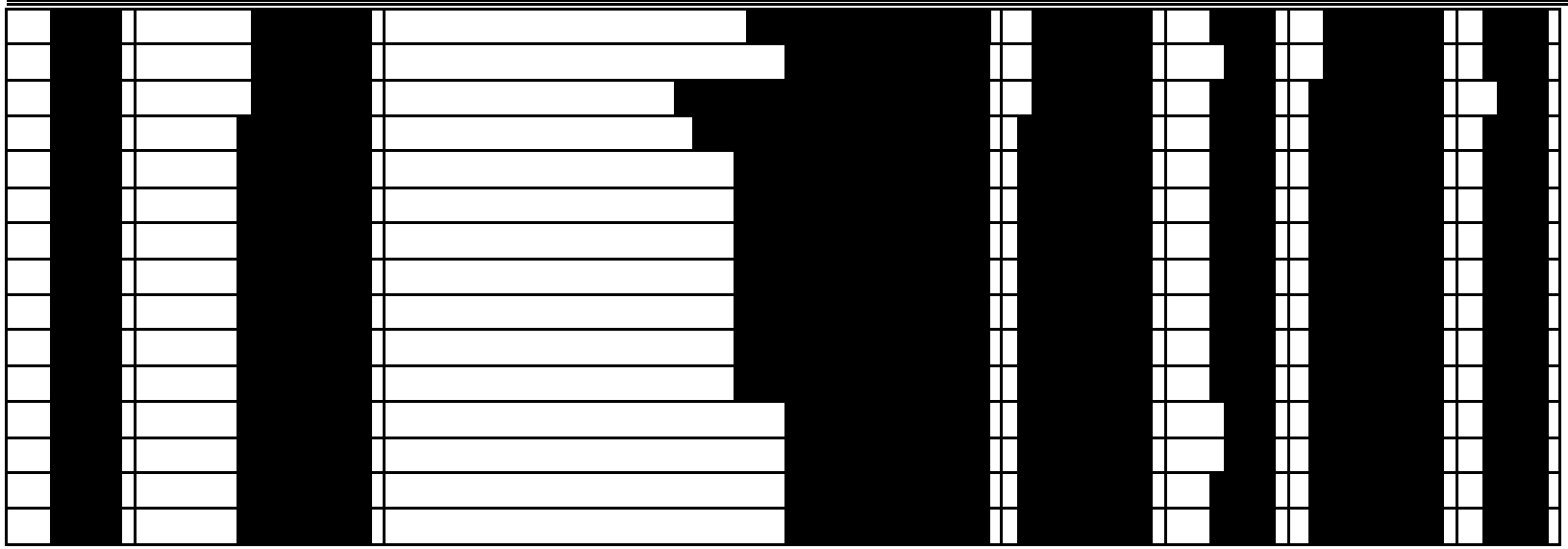












ATTACHMENT 3

Liberty CalPeco's Amended Response to DR CalAdvocates-LIB-A2506017-018

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-018
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-018
Requesting Party:	Public Advocates Office
Originator:	Tyler Holzschuh, Tyler.Holzschuh@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
	Cal Advocates Wildfire Discovery, CalAdvocates.WildfireDiscovery@cpuc.ca.gov
Date Received:	September 25, 2025
Due Date:	October 9, 2025
Response Date:	October 9, 2025
Amended Response Date:	October 31, 2025

This data request pertains to the reconductoring Liberty Utilities was performing one mile away from the ignition point the day the ignition started (as mentioned in Libery-03: Prudence of Operations at 17).

REQUEST NO. 1:

a) Does Liberty Utilities know of any documents on the subject of whether the reconductoring one mile away from the ignition had a relationship to the start of the fire? Such documents include, but are not limited to, documents written by Liberty Utilities and communication between Liberty Utilities and civil litigants.
b) Please provide all documents Liberty Utilities knows of in relation to subpart (a) of Question 1.

AMENDED RESPONSE:

a) Liberty objects to this Question as vague and ambiguous as framed, including with respect to its use of the phrase "relationship to the start of the fire." Subject to and without waiving its objections, Liberty responds as follows: Liberty is not aware of any causal relationship between Liberty's reconductoring work on November 17, 2020, and the ignition of the Mountain View Fire. Thus, Liberty is not aware of any documents regarding such a causal relationship. The reconductoring work in progress was approximately one mile away from the Subject Span and there was a dead-end pole between the Subject Span and the spans subject to the reconductoring work.
b) See Liberty's response to subpart (a).

REQUEST NO. 2:

a) Does Liberty Utilities know of any interviews that were conducted to determine if there were a causal relationship between the reconductoring one mile away and the ignition?
b) If the answer to subpart (a) of Question 2, is yes, then please provide all transcripts and audio files from these interviews.

AMENDED RESPONSE:

a) Liberty objects to this Question as vague and ambiguous as framed, including with respect to its use of the phrase "causal relationship between the reconductoring one mile away and the ignition." Subject to and without waiving its objections, Liberty responds as follows: Liberty is not aware of any causal relationship between Liberty's reconductoring work on November 17, 2020, and the ignition of the Mountain View Fire. Thus, Liberty is not aware of any interviews regarding such a causal relationship.
b) See Liberty's response to subpart (a).

REQUEST NO. 3:

Please provide all of Liberty Utilities' construction standards that Liberty Utilities had in effect between the time periods of the following: (1) those in effect when the east and west poles[1] and the conductors between them were first being constructed, and (2) the present. This includes, but is not limited to, documents on sag and tension requirements for conductors. Please include construction standards for electric utilities that were bought by or otherwise consolidated into Liberty Utilities.

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed, including with respect to timeframe. Subject to and without waiving its objections, Liberty responds as follows: Please see Liberty's attached *Overhead Electric Standards* that were in effect at the time of the Mountain View Fire. Sag and tension requirements for conductors are specified in Liberty's *Overhead Distribution Conductor Stringing Guide (CON05T)*, at pages 378–397 of attachment *Overhead Electric Standards.pdf*. Liberty continues to research earlier construction standards, including those in place at the time of construction of the Specific Facilities, which pre-date Liberty's

[1] The east and west poles refer to those as described to on page two of Liberty Utilities' testimony section Liberty-02: Ignition.

acquisition of the Topaz 1261 Circuit from NV Energy in 2011. Liberty will supplement this Response if it identifies additional construction standards responsive to this Question.

REQUEST NO. 4:

Please provide all documentation for construction that relates to the east and west poles and the conductors between them between the following time periods: (1) the time when the poles and conductors in question were first being constructed, and (2) the present.

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed, including with respect to timeframe. Subject to and without waiving its objections, Liberty responds as follows: Please see *CONFIDENTIAL-Topaz Line Rebuild - Phase Six - As Built.pdf*, for records related to Liberty's rebuild of the East and West Poles and associated conductors in 2022. Liberty continues to research records for the original construction of the East and West poles and the conductors between them, which pre-date Liberty's acquisition of the 1261 Topaz circuit from NV Energy in 2011. Records indicate that the East pole in place at the time of the fire was installed in 1947, and the West pole in 2000 or 2001. Any available construction records are expected to be in hard copy. Liberty will supplement this Response if additional construction records are identified.

REQUEST NO. 5:

Please provide all documentation for construction or inspection that relates to the reconductoring performed approximately one mile away from the Specific Facilities near Walker County Store from October 17, 2020 to November 18, 2020.

RESPONSE:

As explained in *Liberty-03: Prudence of Operations*, at the time of the Mountain View Fire, Liberty was executing Phase Five of the Topaz Line Rebuild approximately one mile away from the Subject Span. See attached file *CONFIDENTIAL-Topaz Line Rebuild - Phase Five – As Built.pdf* for design and construction records related to Phase Five of the Topaz Line Rebuild. Liberty field personnel supervised and inspected the reconductoring project throughout Phase Five of the Topaz Line Rebuild.

REQUEST NO. 6:

a) Were there any dead-end poles between the reconductoring work performed near the Walker County Store and the Specific Facilities on the morning of November 17, 2020? For a definition of dead-end, see the definitions section or page V-35 of General Order 95.
b) If the answer to subpart (a) is yes, please provide the latitude and longitude of each dead-end pole installed as of morning of November 17, 2020 between the reconductoring work being done near the Walker County Store and the Specific Facilities.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty understands this

Question to be asking about the reconductoring project in progress on November 17, 2020, as described in *Liberty-02: Ignition*. Subject to and without waiving its objections, Liberty responds as follows:

a) Yes, there was a dead-end pole between the Subject Span and the spans subject to the reconductoring project in progress on November 17, 2020.
b) The approximate latitude and longitude of the dead-end pole was 38.513318096700885, -119.47106617995865.

REQUEST NO. 7:

a) As of November 17, 2020, did Liberty Utilities' construction standards require a maximum number of tangent poles or power line length between dead-end poles?
b) Please provide all documentation (whole documents if only sections apply) in effect as of November 17, 2020 that relate to subpart (a).
c) As of the present, do Liberty Utilities' construction standards require a maximum number of tangent poles or power line length between dead-end poles?
d) Please provide all documentation (whole documents if only sections apply) in effect as of the present that relate to subpart (c).

AMENDED RESPONSE:

Liberty objects to this Question as vague, ambiguous and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty's standards in effect as of November 17, 2020 did not specify a maximum number of tangent poles or maximum contiguous length of conductor between dead-end poles. The number and spacing of dead-end poles and tangent poles is specified at the time of construction and design based on consideration of various criteria by qualified design personnel at Liberty or a Liberty contractor, including applicable regulatory requirements, conductor type, pole strengths, circuit configuration, loading calculations, terrain, and local conditions.
b) N/A
c) Liberty's current standards do not specify a maximum number of tangent poles or maximum contiguous length of conductor between dead-end poles. The number and spacing of dead-end poles and tangent poles is specified at the time of construction and design based on consideration of various criteria by qualified design personnel at Liberty or a Liberty contractor, including applicable regulatory requirements, conductor type, pole strengths, circuit configuration, loading calculations, terrain, and local conditions.
d) N/A

REQUEST NO. 8:

a) Did the contractors working near Walker County Store on the morning of November 17, 2020 factor the wind speeds at time of construction into the amount of tension applied to the conductors?
b) Please provide all documentation (whole documents if only sections apply) that relates to subpart (a).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty contractors working on the reconductoring project on the morning of November 17, 2020 tensioned conductors consistent with design specifications and standard work methods. Pounds of force of tension and inches of sag for spans being reconductored are specified in the "Sag Tables" of Liberty's *Overhead Distribution Conductor Stringing Guide (CON05T)*, provided in response to Question 3, which is part of Liberty's *Overhead Electric Standards*. Sag tables are provided for GO 95 Heavy Loading Standards, which account for conductor weight with 1/2 inch of 0° F ice and 6 lbs./sq. ft. of wind pressure. Appropriate sag at construction is determined by accounting for span length, ruling span, temperature, and type of conductor. Additional direction for sagging is provided by *Liberty's Standard Sagging Practices (CON06T)*, which is also part of the *Overhead Electric Standards*, as well as the "General Crew Notes" for the Topaz Line Rebuild Phase 5 design specifications. Real-time wind speed at the time of sagging is not a direct input to Liberty's design specifications or work methods for sagging conductors. However, Liberty does not perform sagging of conductors when high winds or other adverse weather conditions would prevent satisfactory sagging.
b) The documents referenced in Liberty's response to subpart (a) of this Question are being provided in response to Question 3 and Question 5 of this set of data requests.

REQUEST NO. 9:

a) As of November 17, 2020, did Liberty Utilities' construction standards require wind speeds at time of construction to be taken into account when applying tension to conductors?
b) As of November 17, 2020, did Liberty Utilities' construction standards require wind speeds at time of construction to be taken into account when applying tension to neutrals?
c) As of November 17, 2020, did Liberty Utilities' construction standards require wind speeds at time of construction to be taken into account when applying tension to messenger wires?
d) Please provide all documentation (whole documents if only sections apply) that relates to subparts (a), (b), and (c).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed, including with respect to the term "messenger wires." Subject to and without waiving its objections, Liberty responds as follows:

a) Please see Liberty's response to subpart (a) of Question 8 of this set of data requests, which describes Liberty's standards and work methods for sagging of conductors.
b) Please see Liberty's response to subpart (a) of Question 8 of this set of data requests, which describes Liberty's standards and work methods for sagging of conductors which also apply to neutrals for ACSR installations.
c) Liberty does not have generalized sagging standards for messenger wires, which are utilized only in spacer cable installations where they serve as neutrals in a 4-wire

configuration. Tree wire configurations are custom-designed in accordance with GO 95 and the physical properties of the conductors and messengers.

d) The documents referenced in Liberty's response to subpart (a) of Question 8 are being provided in response to Question 3 and Question 5 of this set of data requests.

ATTACHMENT 4

PacifiCorp's Public Safety Power Shutoff History Commission Dashboard

CPUC Public PSPS Dashboard

Public Safety Power Shutoff Event Data Since 2018

(See second tab for PSPS event map)

Event	IOU	Date Range
All Events	Liberty Utilities, PacifiCorp 2	No date selected

List of Events

Event Name	Customers ...
Liberty Utility PSPS Event 11/05/25	1,443
Liberty Utility PSPS Event 11/22/24	1,064
Liberty Utility PSOM Event 11/20/24	56
Liberty Utility PSPS Event 11/20/24	1,491
Liberty Utility PSPS Event 11/13/24	0
Liberty Utility PSPS Event 11/11/24	686
Liberty Utility PSOM Event 10/21/22	0
Liberty PSPS Event 09/19/21	0
PacifiCorp PSPS Event 08/17/21	1,953
Pacificorp PSPS Event 10/25/20	0
Pacificorp PSPS Event 09/11/20	2,559

1 of 11

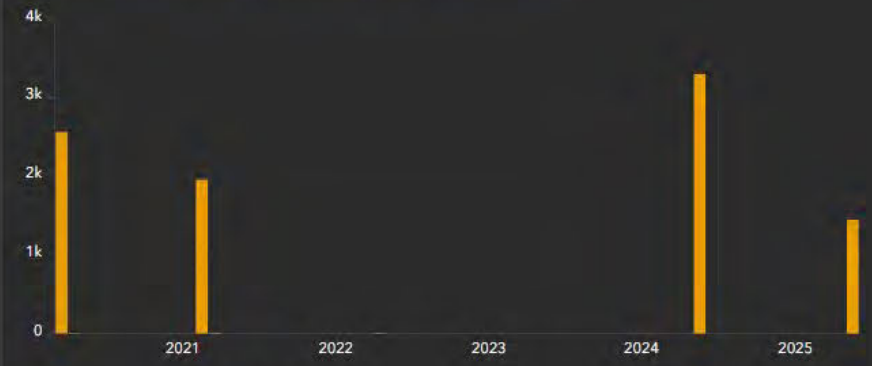
PSPS Event Details

Event Name	Liberty Utility PSPS Event 11/05/25
First Date of POC	11/5/25
IOU	Liberty Utilities
De-energization Status	Yes
De-energization Starting Date	11/5/25
Full Restoration Date	11/5/25
Customers Notified	1,443
Customers De-energized	1,443
Cancelled/Removed from Scope	0
MBL De-energized	13
Counties De-energized	2
Tribes De-energized	1
Transmission Circuits De-energized	0
Distribution Circuits In Scope	2
Distribution Circuits De-energized	2
Damages/Hazards	3
CFCI De-energized	75
CRC/CCV/CRV Open	2

Number of Events Each Month by Utility

Events/Month | Events/Year

Number of Customers De-energized Each Month



De-energized/Month | De-energized/Year | Notified/Month | Notified/Year

CA-08-0065

ATTACHMENT 5

PacifiCorp's Annual California Electric Reliability Report Calendar Year 2021 Review

Energy Division Central Files Document Coversheet

Directions: Submit all documents and submittal questions to Energy Division Central Files via email EnergyDivisionCentralFiles@cpuc.ca.gov

1. Fill out coversheet completely. Coversheet can be embedded as page 1 of the electronic compliance filing, or can be submitted as a separate document that is attached to the email that delivers the compliance filing.
2. If the coversheet is submitted as separate document, please name the coversheet file with the same document name used in your primary document (see Section A) + plus the word "cov" (for coversheet). For example, the name of the coversheet file will be something like: ***PacifiCorp Monthly Gas Report 201602 COV.docx***
3. If the document is confidential, add CONF (for confidential). For example, the name of the coversheet file will be something like: ***PacifiCorp Monthly Gas Report 201602 CONF.docx*** and ***PacifiCorp Monthly Gas Report 201602 COV CONF.docx***
4. All documents are required to be submitted in an electronically *searchable* format.
5. Documents need to reference the reason for the mandate that ordered the filing in Section B or C. If you are unable to reference a proceeding or explain the origin of your filing, please contact Energy Division Central Files.
6. To find a proceeding number (if you only have a decision number), go to http://docs.cpuc.ca.gov/DecisionsSearchForm.aspx; enter the decision number, and the results shown include the proceeding number.

A. Document Name

Today's Date: 7/15/2022

1. Utility Name: PacifiCorp d/b/a Pacific Power (U 901 E)
2. Document Submission Frequency (Annual, Semi-Annual, YTD, Quarterly, Monthly, Weekly, Ad-hoc, Once, Other Event): Annual
3. Report Name: Electric Reliability Report
4. Reporting Interval (for this submission, e.g. 2015 Q1 – that data date): CY 2021
5. Document File Name (format as 1+2 + 3 + 4): PacifiCorp Annual Electric Reliability Report CY 2021
6. Append the confidential and/or cover sheet notation, as appropriate. CONF

Sample Document Names:
Utility Name + Submittal Frequency + Report Name + Year + Reporting Interval + (COV or CONF or both or neither)

PacifiCorp Annual Electric Reliability Report CY 2021 PUBLIC	*PacifiCorp Annual Electric Reliability Report CY 2021 CONF*

7. Identify whether this filing is ☒original or ☐revision to a previous filing.
   a. If revision, identify date of the original filing: Click here to enter text.

B. Documents Related to a Proceeding

All submittals should reference both a proceeding and a decision, if applicable. If not applicable, leave blank and fill out Section C.

1. Proceeding Number (starts with R, I, C, A, or P plus 7 numbers): R.14-12-014
2. Decision Number (starts with D plus 7 numbers): D. 16-01-008
3. Ordering Paragraph (OP) Number from the decision: Ordering Paragraph 1

Energy Division Central Files Document Coversheet

C. Documents Submitted as Requested by Other Requirements

If the document submitted is in compliance with something other than a proceeding, (e.g. Resolution, Ruling, Staff Letter, Public Utilities Code, or sender's own motion), please explain:

D. Document Summary

Provide a Document Summary that explains why this report is being filed with the Energy Division. This information is often contained in the cover letter, introduction, or executive summary.

D.16-01-008 OP 1 requires all electric utilities to submit system level and district or division level electric reliability information to the Commission on July 15 of each year.

E. Sender Contact Information

1. Sender Name: Jennifer Angell
2. Sender Organization: PacifiCorp d/b/a Pacific Power (U 901 E)
3. Sender Phone: (503) 331-4414
4. Sender Email: jennifer.angell@pacificorp.com

F. Confidentiality

1. Is this document confidential? ☐No ☒Yes

   a. If Yes, provide an explanation of why confidentiality is claimed and identify the expiration of the confidentiality designation (e.g. Confidential until December 31, 2020.) On January 14, 2016, the Commission approved D.16-01-008 updating the electric reliability reporting requirements for California electric utilities. D.16-01-008 requires utilities to submit annual information about planned outages to the Energy Division and the Safety and Enforcement Division on a confidential basis. As noted in D.16-01-008, "making planned outage data should be confidential to protect the public from potential harmful activities that could damage the grid and electric reliability." See D.16-01-008 at p.19. A signed declaration for confidential treatment is provided with submission of the annual electric reliability report for 2021.

G. CPUC Routing

Energy Division's Director, Ed Randolph, requests that you not copy him on filings sent to Energy Division Central Files. Identify below any Commission staff that were copied on the submittal of this document.

1. Names of Commission staff that sender copied on the submittal of this Document: Lee Palmer, Julian Enis, Forest Kaser

ver.5/19/2016

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 15, 2022

VIA ELECTRONIC FILING AND
OVERNIGHT DELIVERY

Leuwam Tesfa, Deputy Executive Director, Energy & Climate Policy
Lee Palmer, Director, Safety Enforcement Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102-3298
EnergyDivisionCentralFiles@cpuc.ca.gov
Lee.Palmer@cpuc.ca.gov

RE: PacifiCorp (U 901-E) Annual Electric Reliability Report in Compliance with D.16-01-008

In compliance with California Public Utilities Commission Decision (D.) 16-01-008, enclosed is PacifiCorp's Annual Electric Reliability Report for January 1, 2021 – December 31, 2021.

Please note that the planned outage data is considered confidential subject to California Public Utilities Code Section 583, General Order 66-D and D.16-01-008. In compliance with D.16-01-008, this information is submitted under seal. A signed declaration in support of the request for confidential treatment is also provided with this submission.

If you have any questions, please contact Amy McCluskey, Managing Director, Wildfire Safety & Asset Management, at (503) 813-5493, or Pooja Kishore, Regulatory Affairs Manager, at (503) 813-7314.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosure

Cc: Julian Enis, Julian.Enis@cpuc.ca.gov
Forest Kaser, Forest.Kaser@cpuc.ca.gov

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

PacifiCorp d/b/a Pacific Power

Annual California Electric Reliability Report

(PUBLIC VERSION)

Calendar Year 2021 Review
(January 1 – December 31, 2021)

Table of Contents

Introduction

In rulemaking (R.)14-12-014, the California Public Utilities Commission developed rules regarding changes to the state's required reliability reporting requirements for California investor-owned electric utilities (IOUs), as outlined in Decision (D.) 16-01-008[1] (the Order). The report is being filed in compliance with those rules. The scope of the rulemaking included the following tasks:

1. Review of current reliability reporting requirements;
2. Develop revised annual reporting requirements that include information about frequency and duration of outages;
3. Define the term "local area" for reliability reporting;
4. Clarify the term "major event day" (to align with definition of local area for reliability reporting);
5. Develop criteria and methodology for identifying worst performing circuits;
6. Develop an approach for demonstrating cost-effective remediation and determining cost recovery procedures;
7. Consider whether the IOUs should be allowed to set up memorandum accounts for remediation costs; and
8. Develop an annual outreach plan and related reporting to inform customers about planned and unplanned outages.

The Order includes the following requirements:

1. IOUs shall submit system level and district or division level electric reliability information to the Commission on July 15 of each year.
2. IOUs shall submit draft copies of the reports prepared for July 15, 2016 and July 15, 2017 to the Energy Division Director in electronic format at least 45 days prior to the July 15 deadline. Draft copies for subsequent reporting years shall be required at the discretion of the Energy Division Director.
3. Commission staff, in consultation with the IOUs, has the authority to require any necessary revisions to the draft reports before they are made public.
4. Pacific Gas and Electric Company shall combine in one single report the electric reliability reporting requirements pursuant to Decision (D.) 96-09-045 and D.04-10-034.
5. IOUs shall use the electric reliability reporting template at Appendix B of the Order to create their annual reports.
6. IOUs shall publish on their internet websites or provide to customers via U.S. mail, procedures for making requests about electric circuits that serve their homes or businesses.
7. IOUs shall conduct at least one annual public in-person presentation about the information in their annual electric reliability reports.
8. IOUs shall make webinar participation available for their annual in-person events so that their customers can attend the presentation remotely or in-person.
9. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall annually report the worst performing one percent of the circuits among all the electric circuits in their respective service territories.
10. Bear Valley Electric Service, Liberty Utilities, LLC and PacifiCorp shall report the following number of circuits on their list of worst performing circuits: three circuits for PacifiCorp; two circuits for Liberty Utilities, LLC; and one circuit for Bear Valley Electric Service.
11. IOUs shall provide reliability data at both the system and the district level. Whatever major event days are determined for calculations at the system level shall also be used for reliability calculations at the district or division level.

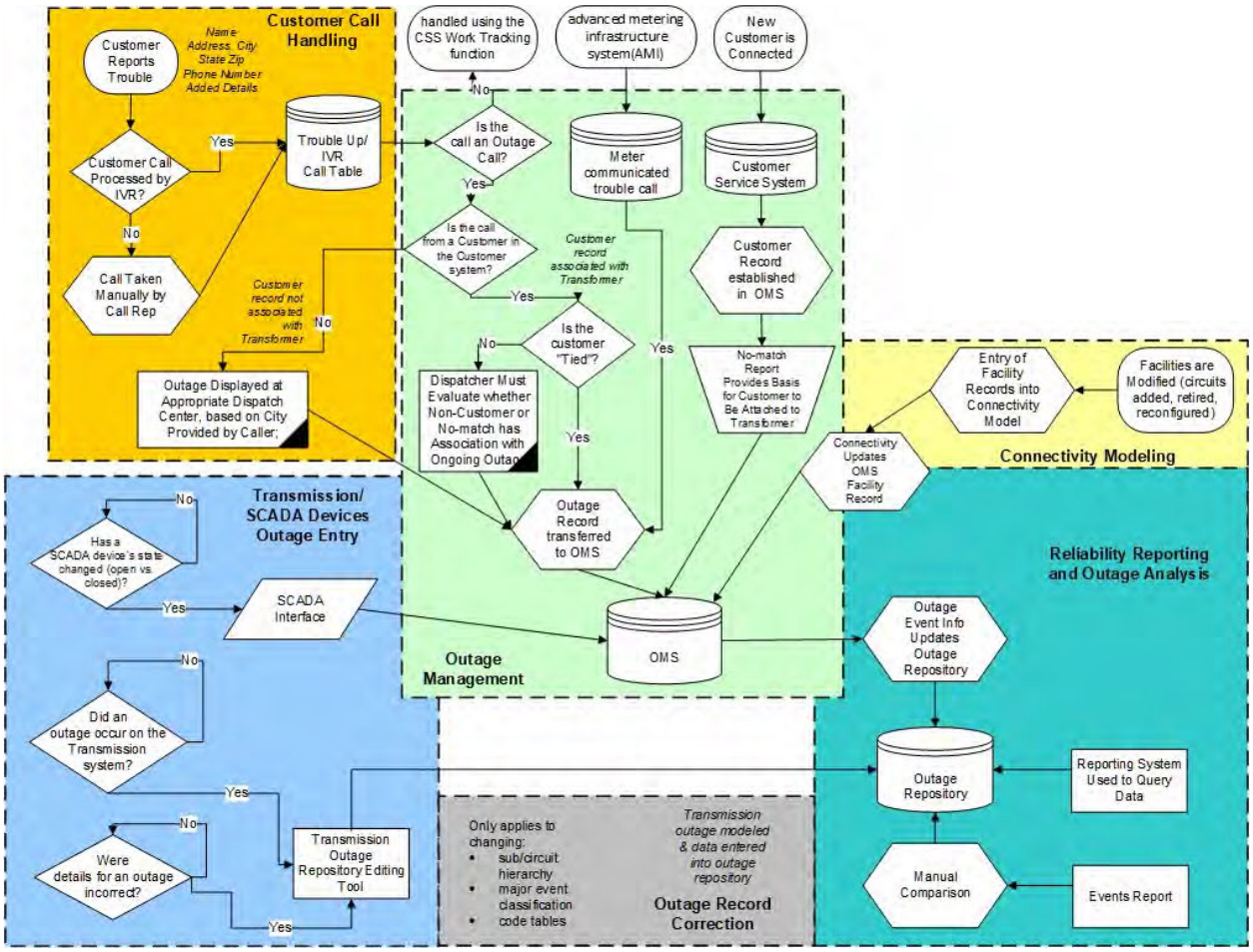
[1] D.16-01-008 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M157/K724/157724560.PDF

12. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall respond to customer inquiries about electric reliability within 15 business days.
13. Bear Valley Electric Service, Liberty Utilities, LLC and PacifiCorp shall respond to customer inquiries about electric reliability within 30 business days.
14. IOUs should meet and confer to consolidate unidentified reliability reporting requirements from Commission decisions and General Orders into a single Commission decision and general order.
15. IOUs shall submit a single joint proposal for a proposed consolidated decision and general order to the directors of the Energy Division and the Safety and Enforcement Division within one year from the date of the Order.

This report serves to fulfill the foregoing reporting requirements of the Order. In addition, this report includes a description of PacifiCorp's outage data collection process, the applicable conventions, indices and definitions, methods used by PacifiCorp to determine cost-effective reliability improvement opportunities, PacifiCorp's worst performing circuits and PacifiCorp's service territory map.

Outage Data Collection Process

PacifiCorp operates automated outage management and reporting systems; a diagram of the data flow process is shown below. Customer trouble calls and SCADA events are interfaced with the Company's real-time network connectivity model, its CADOPS system (Computer Aided Distribution Operations System). Upon implementation of the company's advanced metering infrastructure system (AMI), which occurred since the last annual report, meters also communicate trouble calls into CADOPS. By overlaying these events onto the network model, the program infers outages at the appropriate devices (such as a transformer, fuse or other interrupting device) for all customers down line of the interrupting device. The outage is then routed to appropriate field operations staff for restoration and the outage event is recorded in the Company's Prosper/US outage repository. In addition to this real-time model of the system's electrical flow, the Company relies heavily upon the SCADA system it has in place. This includes the Dispatch Log System (an SQL database application) which serves to collect all events on SCADA-operable circuits. That data is then analyzed for momentary interruptions to establish state-level and circuit-level momentary interruption indices. Only those circuits (and the customers who are served from those devices) outfitted with SCADA equipment are considered within the calculations.



Data Collected: Conventions, Indices and Certain Definitions

SAIDI, SAIFI, CAIDI and MAIFI are the most common indicators or indices used by utilities across the nation for measuring and reporting reliability. Along with other indices, they were first rigorously documented in Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-1998, and since modified in IEEE 1366-2003/2012, IEEE Guide for Electric Power Distribution Reliability Indices.

For performance reporting as contained within this document, PacifiCorp uses the current standard indices, applied at the state level as well as to each of the districts in which it provides service; these serve as "local areas" as defined within reporting requirements. Major event days are calculated at the state level and then applied at each of these districts consistent with the requirements of D.16-01-008. PacifiCorp collects outage data on all outages on the source side of the electric meter. When it is required to interrupt power in order to perform work on the system, it records these outages with a separate designation to identify whether they were taken without notice, or whether the outages were pre-arranged or planned. For the purposes of the data provided in this report, Planned Outages are those in which either the customer or the Company made arrangements for the power interruption to occur; in certain situations the notice may be very short, while generally two days' notice is the goal. These may also often be referred to as Maintenance Outages. Certain other outages may be performed intentionally by employees, without notice (such as when a car strikes a utility pole and the crew replacing the damaged pole takes an operational outage) but since they happen precipitously are not generally classified as Planned Outages.

As part of the Company's wildfire mitigation programs, the Company may use protection coordination settings, referred to as "Elevated Fire Risk" (EFR) settings, that more substantially affected distribution system performance

than standard settings. In 2021, the Company developed a method to estimate the reliability impacts of the device setting changes. EFR settings are generally applied when fire weather conditions, such as high winds, low fuel moisture, high temperature, low relative humidity and volatile fuels, are greatest. When EFR settings are used, certain operational responses may also differ, which may result in more sustained outage events and longer outage duration. The underlying metrics reported exclude outages where EFR settings were applied.

Furthermore, the Company also collects information about outages which happen on equipment at voltages higher than distribution level, specifically the transmission or generation system; transmission voltages within PacifiCorp are those in excess of 34.5 kilovolt (kV). If an interruption occurs to distribution customers as a result of events at those facilities it designates these outages as Loss of Supply outages and denotes them in this report as Transmission.

Cost Effective Improvements

PacifiCorp uses its reliability data in a variety of ways that are designed to improve reliability to its customers. It has devised methods that are contained in the industry guide for electric reliability, IEEE 1782-2014.[2] Some of these analytical methods render the outage data in a tabular, graphical or geospatial manner. All of them serve as inputs to identify and develop projects that improve reliability using the Company's fuse coordination program (Fuse It or Lose It: FIOLI), its circuit hardening program (Saving SAIDI), and its capital construction program (Network Initiatives). It evaluates the history of outages within a circuit and at specific devices (fuses, reclosers, circuit breakers) across the entire service area and determines the probability of avoiding outages of specific cause categories. The programs (FIOLI, Saving SAIDI and Network Initiatives) are evaluated for their forecast improvements to network reliability, as measured by the avoidance of customer interruptions, customer minutes interrupted and momentary customer interruptions. Each project has a value calculated for the cost of the project divided by the avoided interruptions. PacifiCorp uses this cost per avoided customer interruption and customer minute interrupted to identify cost-effective reliability improvement projects. It assembles each of these candidate projects and their cost to benefit value into a project priority listing which rank orders the projects and based upon the best-cost projects, prepares a suite of projects that align with metric improvement and budget targets. As projects are completed the list is re-evaluated to determine whether reliability performance or funding levels have changed and warrant modifications to the plan.

Worst Performing Circuits

Additionally, PacifiCorp calculates a "Circuit Performance Indicator" which is a blended multi-year metric for the circuit, applying weighted circuit SAIDI, SAIFI, MAIFI and breaker lockout events. This metric ensures that no one index is emphasized for overall reliability, and that if a customer is experiencing a mix of sustained and momentary interruptions the combination of these events is being accorded proper consideration in elevating that circuit for improvement. This metric excludes outages which are Planned, Transmission or Major Events, and is identified as CPI99. The equation and weightings are detailed below.

CPI99

CPI99 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. It excludes Major Event and Loss of Supply (Transmission) outages. The variables and equation for calculating CPI are:

CPI = Index * ((SAIDI * WF * NF) + (SAIFI * WF * NF) + ($MAIFI_E$ * WF * NF) + (Lockouts * WF * NF))

Index: 10.645
SAIDI: Weighting Factor 0.30, Normalizing Factor 0.029
SAIFI: Weighting Factor 0.30, Normalizing Factor 2.439

[2] 1782 (PE/T&D) Guide for Collecting, Categorizing and Utilization of Information Related to Electric Power Distribution Interruption Events was approved on March 27, 2014, and contains many of the approaches used by PacifiCorp to evaluate system reliability and determine areas where improvements should be deployed.

$MAIFI_E$: Weighting Factor 0.20, Normalizing Factor 0.70
Lockouts: Weighting Factor 0.20, Normalizing Factor 2.00
Therefore, 10.645 * ((3-year SAIDI * 0.30 * 0.029) + (3-year SAIFI * 0.30 * 2.439) + (3-year $MAIFI_E$* 0.20 * 0.70) + (3-year breaker lockouts * 0.20 * 2.00)) = CPI Score

Those circuits whose scores are poorer (higher) than may be warranted, given the number of customers it serves, the exposure and the location of the circuit are identified as candidate worst performing circuits. Within five years of selection the score must be improved (lowered) by a targeted amount. If that improvement has not been achieved additional work may be implemented to further improve the circuit performance.

In selecting its three worst performing circuits, PacifiCorp uses CPI99 as its preferred metric, as discussed above, and targets a 20% improvement in that metric for the family of circuits selected within five years of their selection. If a given circuit is identified as a worst performing circuit in successive years, it would be asterisked and additional parameters would be required to be reported.

The Order directs utilities in the following manner regarding worst performing circuit selection.[3]

> b. Any circuit appearing on this list of "deficient" (WPC) circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:
>
> > i. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;
> > ii. A historical record of the metric;
> > iii. An explanation of why it was on the deficiency list again;
> > iv. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and
> > v. A quantitative description of the utility's expectation for that circuit's future performance.

Below are the circuits selected as worst performers for 2022. Since no circuit was a repeat selection[4] the details listed above are not required.

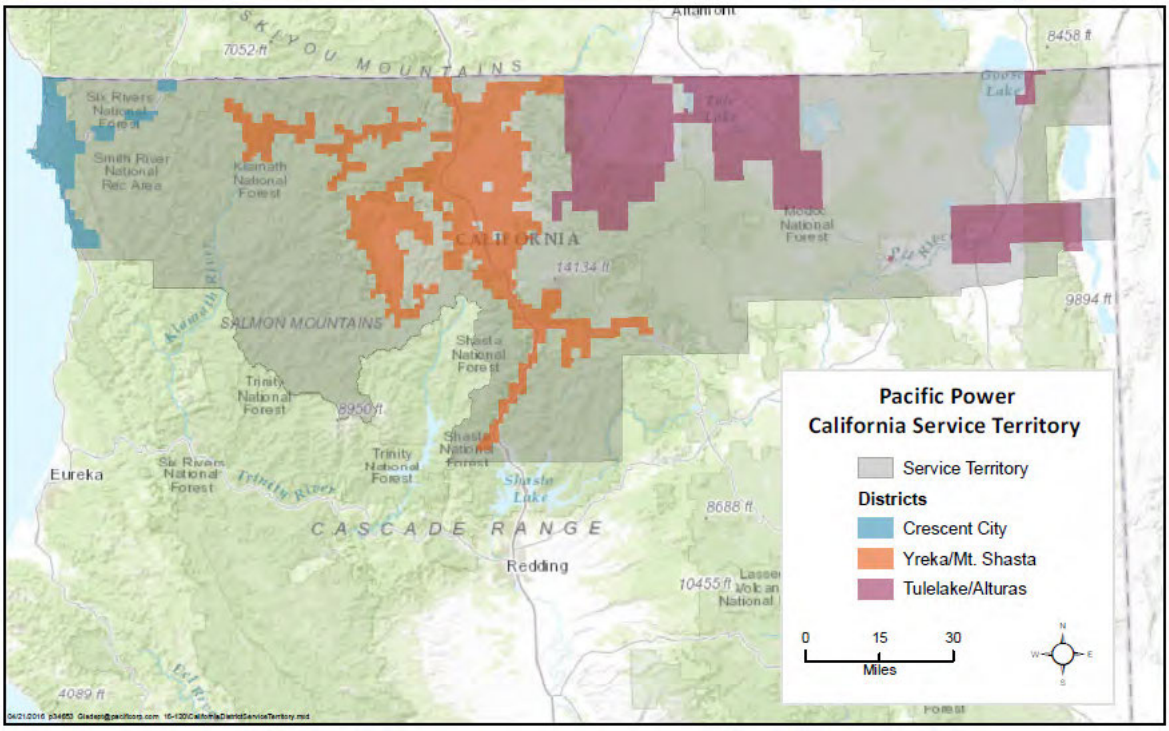
Top 3 Worst Performing Circuits			
Program Year 23: (CY2022)			
Circuit Name	**Sawmill (5R171)**	**Shasta Spr (5G69)**	**Red Rock (4L3)**
District	Crescent City	Yreka/Mt. Shasta	Tulelake
Customer Count	419	523	463
Substation Name	Yurok	North Dunsmuir	MacDoel
Circuit-Miles	64 miles	41 miles	381 miles
% OH	89%	88%	98%
% UG	11%	12%	2%
# Breaker/Recloser Operations[5]	46	46	1

[3] D.16-01-008 p. 3.
[4] In 2021, the three circuits identified as WPCs were Crescent Ctr (5R160), Nutgale, (8G95), and Shastina (5G45). In 2020, the three circuits identified as WPCs were Florence Ave (7G71), Seiad Crk (5G39), and Snowbush (6G101). In 2019, the three circuits identified as WPCs were Bell-Air (5G83), Peach Orchard (5G2), and Southbank (5R165). In 2018, the three circuits identified as WPCs were Town (5G16), South (5G99), and Patrick's Creek (6R3).
In 2017, the three circuits identified as WPCs were Scott Bar (5G40), Etna Tie (5G41), and Pine Grove (5R152).
[5] 2021 Operation counters are a physical counter on the equipment that ticks off an operation every time the breaker is operated regardless of how or why it is operated.

# Fault Counts[6]	37	5	1
CPI99 Baseline	137	120	138
Preferred Baseline	**109**	**96**	**110**
Designated as Worst Performer in Prior Year[7]?	**No**	**No**	**No**

Service Territory Map

The graphic below shows PacifiCorp's service territory and identifies the districts used in this report.



[6] 2021 Fault counters are a manual calculation that is determined by operation counters that are found to have operated with an unknown cause (usually a fault on the line).

[7] Designation of WPCs in accordance with this program began in 2017.

State Reliability Underlying Indices - Excluding Planned Outages: Ten-Year SAIDI, SAIFI, MAIFI and CAIDI Results

PacifiCorp uses the current standard indices for performance reporting, as described within this document, at the state level and at reliability reporting regional levels. System Indices are calculated based on the IEEE 1366 method, which excludes Planned and ISO outages and includes generation outages. Major Events are determined using the "2.5 beta" statistical method to determine the threshold for a major event, as outlined in IEEE 1366 and performance with and without major events are both reported. For more on the reporting period's major events see Section 7.

Distribution

Distribution outages include any outage where the device which operates is downstream of the high side disconnect of the substation down to the customer's meter.

Distribution System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	160.9	1.671	96	1.639	78.4	0.814	96	1.639
2020	251.5	0.733	343	0.556	87.5	0.610	144	0.556
2019	419.7	1.236	340	0.721	70.2	0.473	149	0.721
2018	202.5	1.036	195	2.478	72.0	0.688	105	2.478
2017	421.8	1.426	296	4.422	75.5	0.607	125	4.422
2016	130.8	0.858	152	2.554	96.2	0.719	134	2.554
2015	297.5	1.110	268	4.330	100.0	0.674	148	4.330
2014	199.4	0.889	224	2.640	160.8	0.840	191	2.640
2013	127.4	0.740	172	4.171	123.1	0.705	174	4.171
2012	341.3	1.248	273	6.936	165.5	1.015	163	6.936

Notes:

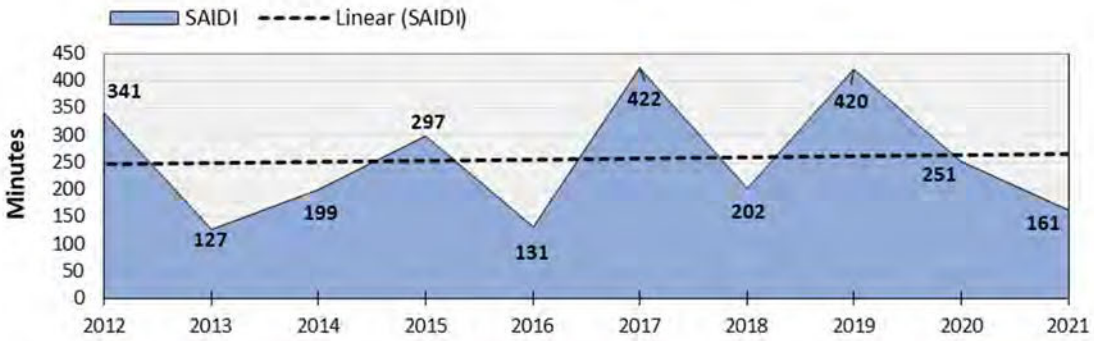
1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

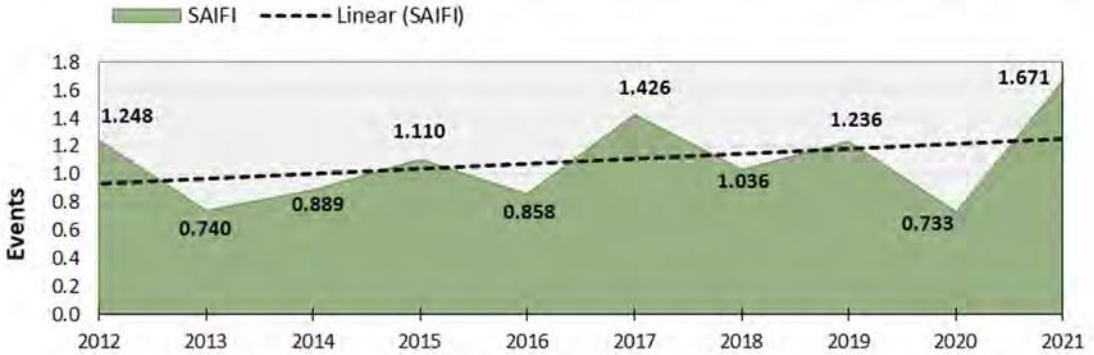
2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

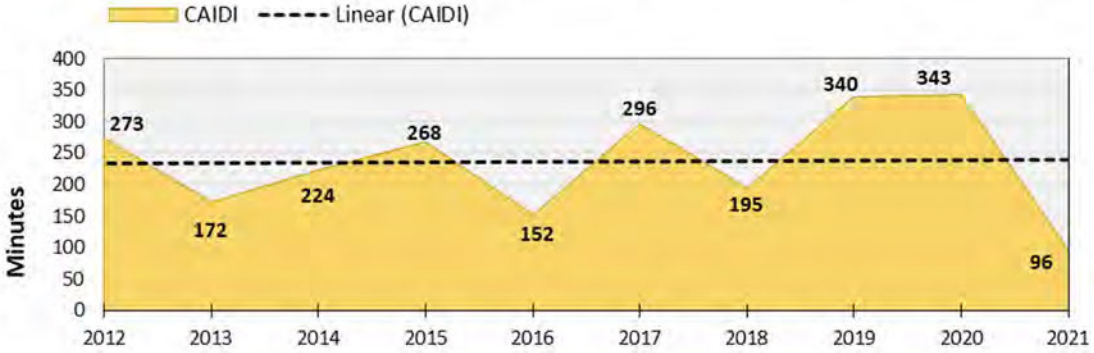
3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

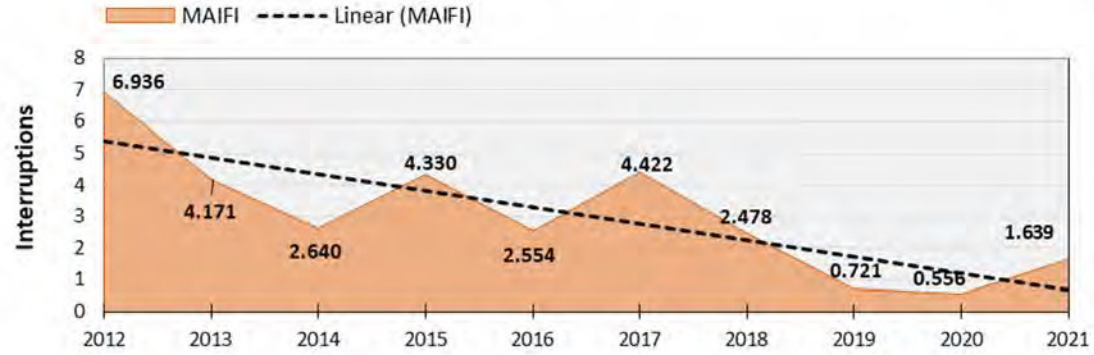
Distribution Reliability History - *Including Major Events*

(excludes customer notice given and customer requested)



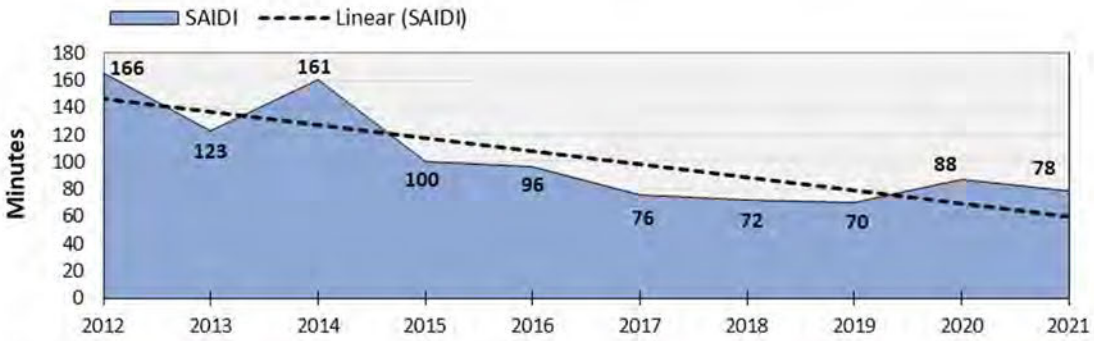


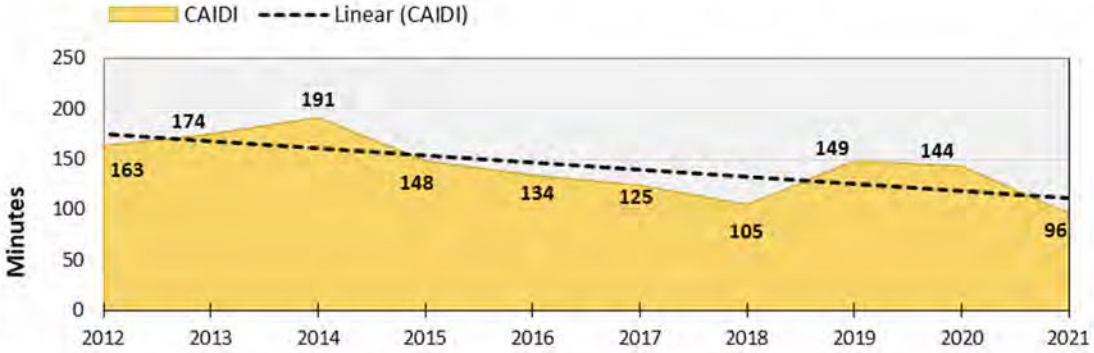


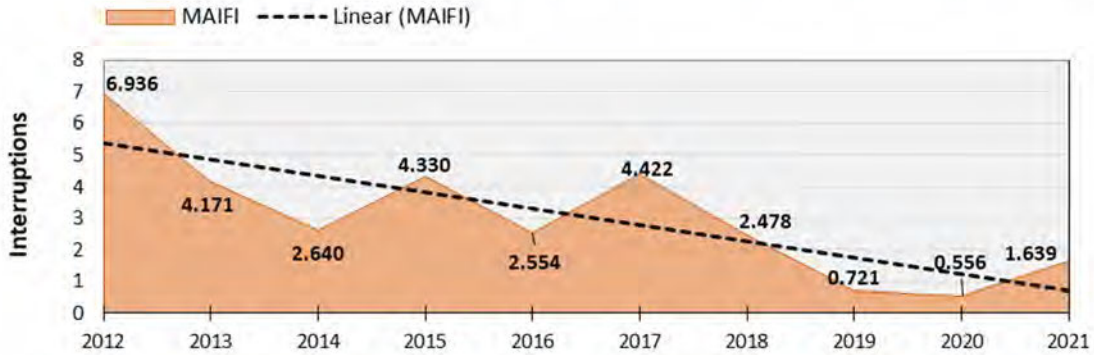


Distribution Reliability History - *Excluding Major Events*

(excludes customer notice given and customer requested)







Transmission

Transmission outages include any outage where the device that operates is upstream of the substation transformer. This can include outages that are the result of generator operations. Transmission voltages are in excess of 34.5 kilovolt (kV).

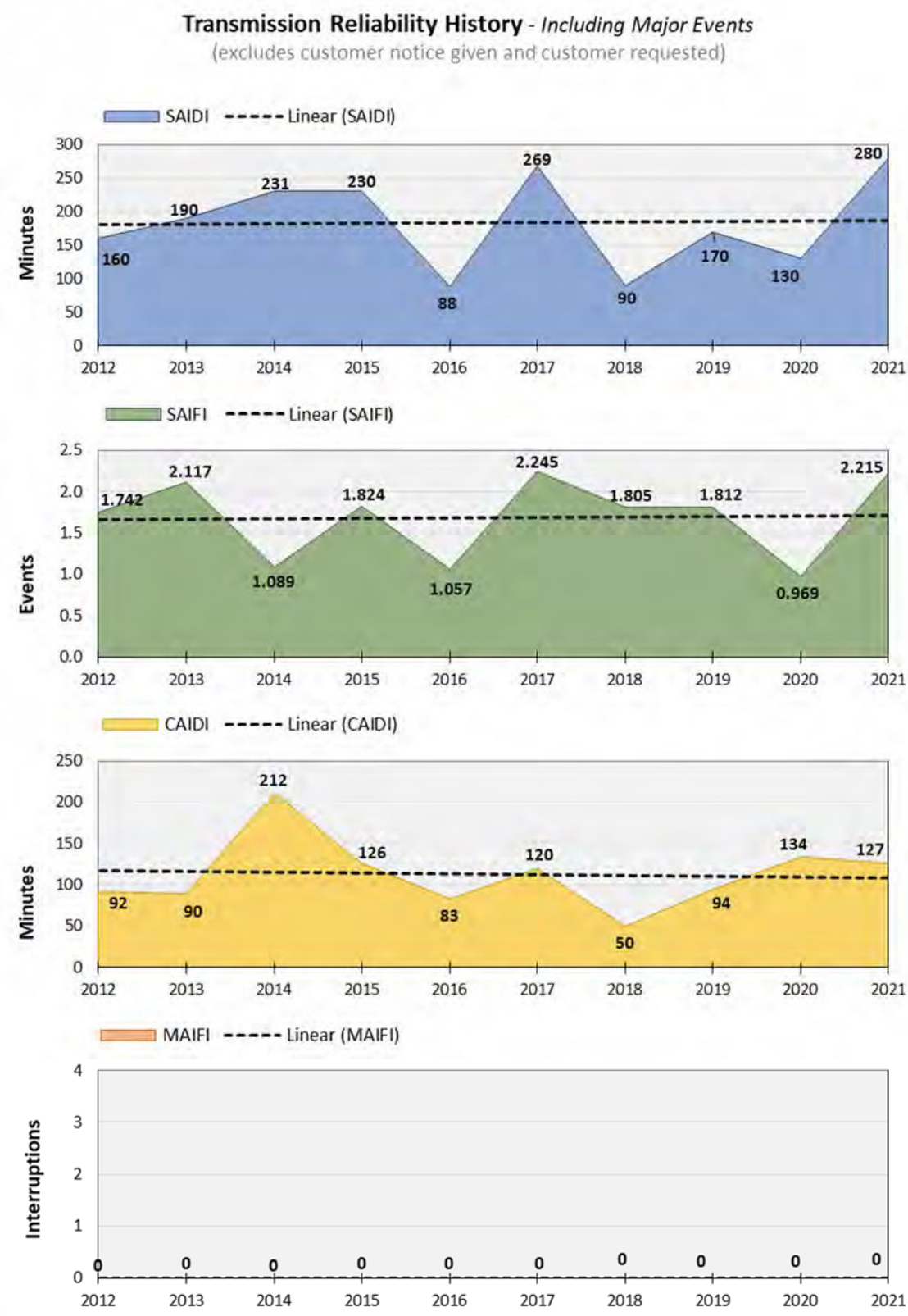
Transmission System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	280.2	2.215	127	0	37.2	0.851	44	0
2020	129.9	0.969	134	0	45.3	0.488	93	0
2019	169.9	1.812	94	0	36.1	0.365	99	0
2018	89.6	1.805	50	0	37.0	1.275	29	0
2017	269.1	2.245	120	0	46.6	1.144	41	0
2016	88.1	1.057	83	0	46.5	0.714	65	0
2015	230.4	1.824	126	0	81.9	1.013	81	0
2014	230.5	1.089	212	0	72.7	0.586	124	0
2013	189.9	2.117	90	0	88.8	1.535	58	0
2012	160.5	1.742	92	0	94.0	1.225	77	0

Notes:

1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

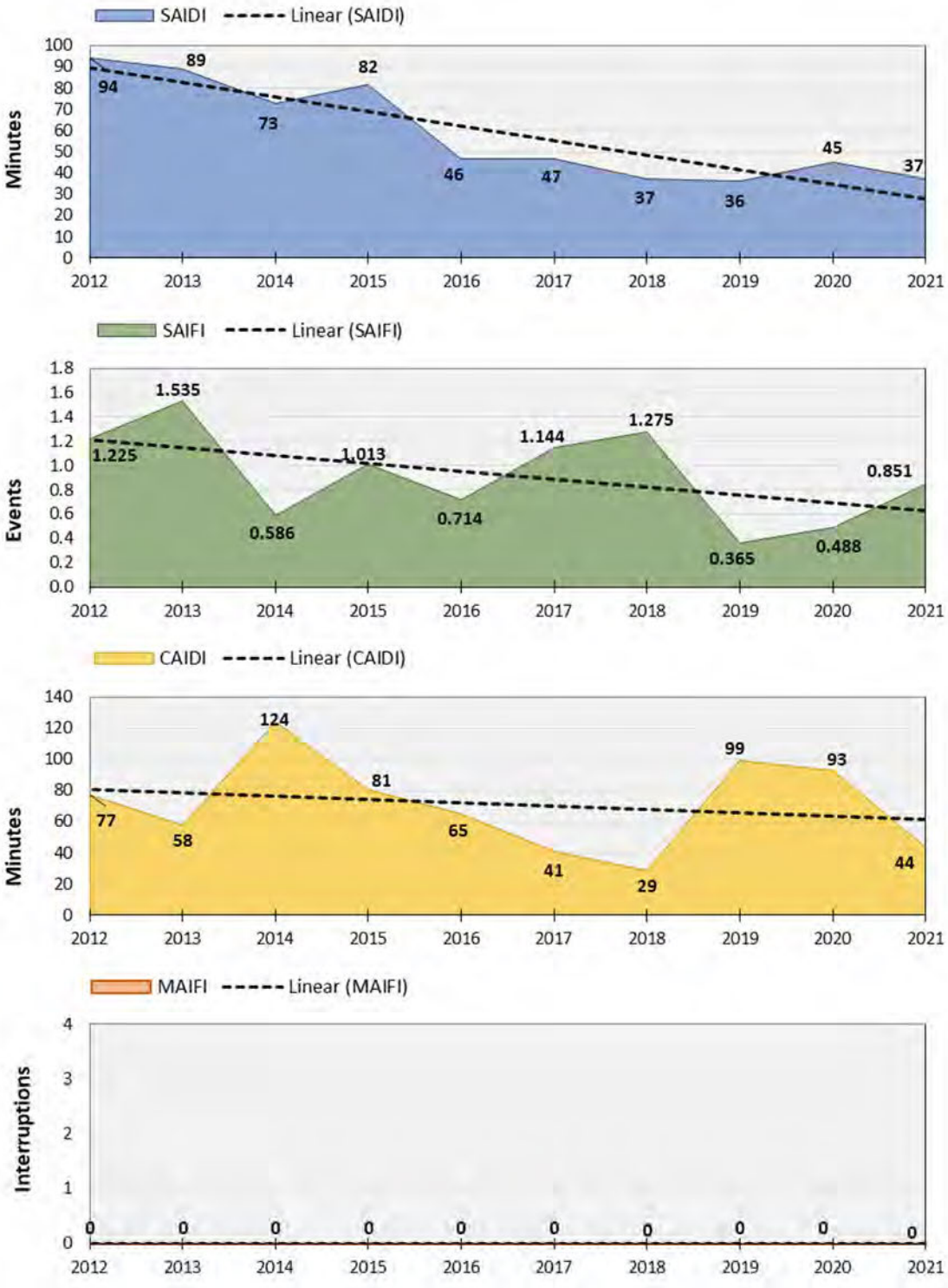
2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.


Transmission Reliability History - Including Major Events
(excludes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
300
250
200
150
100
50
0
160
190
231
230
88
269
90
170
130
280
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
SAIFI
Linear (SAIFI)
Events
2.5
2.0
1.5
1.0
0.5
0.0
1.742
2.117
1.089
1.824
1.057
2.245
1.805
1.812
0.969
2.215
CAIDI
Linear (CAIDI)
Minutes
250
200
150
100
50
0
92
90
212
126
83
120
50
94
134
127
MAIFI
Linear (MAIFI)
Interruptions
4
3
2
1
0
0
0
0
0
0
0
0
0
0
0

Transmission Reliability History - *Excluding Major Events*

(excludes customer notice given and customer requested)



CA-08-0083

Combined Transmission and Distribution

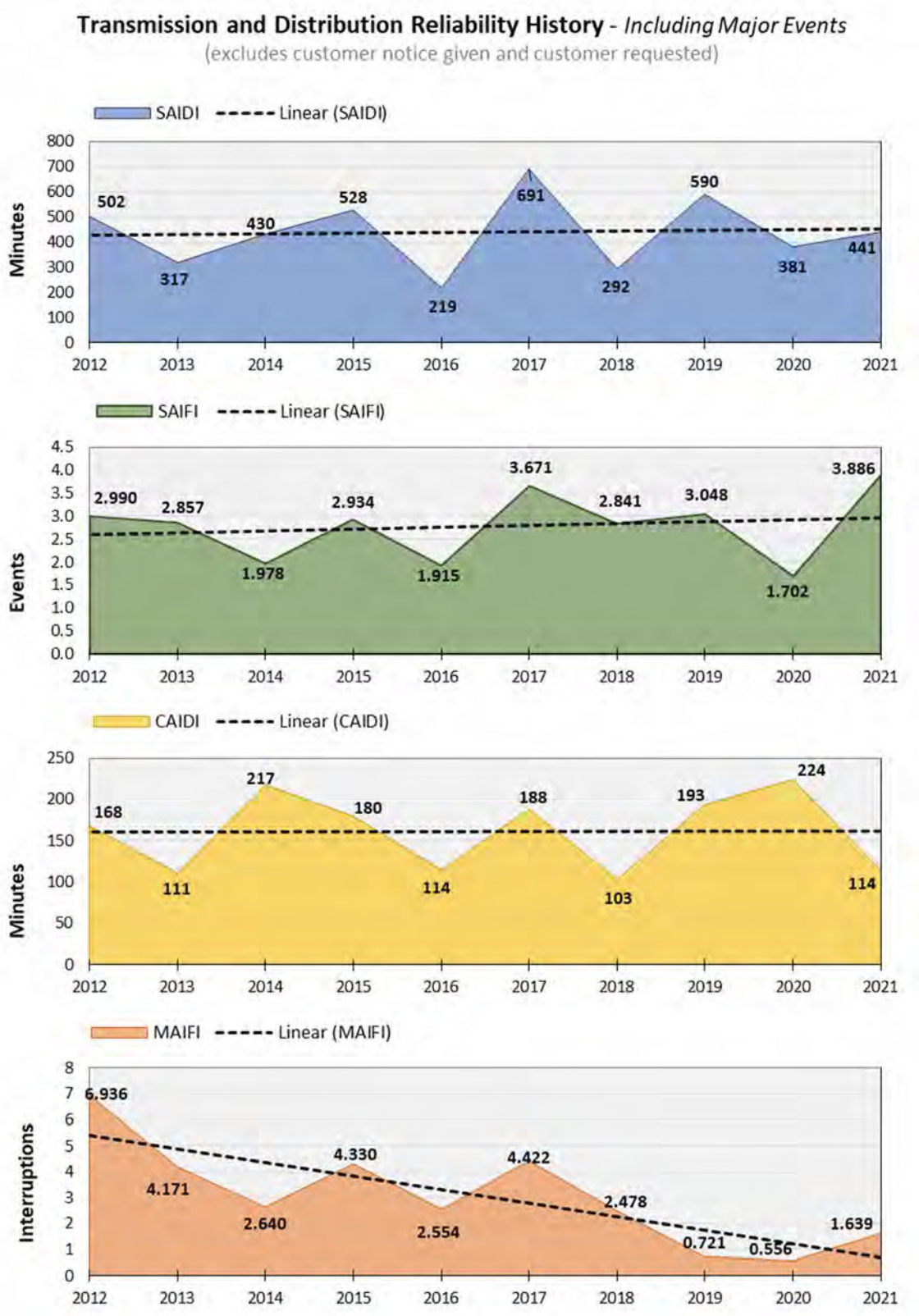
Combined Transmission and Distribution System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI [3]
2021	441.1	3.886	114	1.639	115.6	1.665	69	1.639
2020	381.4	1.702	224	0.556	132.9	1.098	121	0.556
2019	589.7	3.048	193	0.721	106.3	0.838	127	0.721
2018	292.1	2.841	103	2.478	108.9	1.963	55	2.478
2017	690.9	3.671	188	4.422	122.2	1.751	70	4.422
2016	218.9	1.915	114	2.554	142.7	1.433	100	2.554
2015	527.8	2.934	180	4.330	181.9	1.687	108	4.330
2014	430.0	1.978	217	2.640	233.6	1.426	164	2.640
2013	317.3	2.857	111	4.171	211.9	2.240	95	4.171
2012	501.8	2.990	168	6.936	259.5	2.240	116	6.936

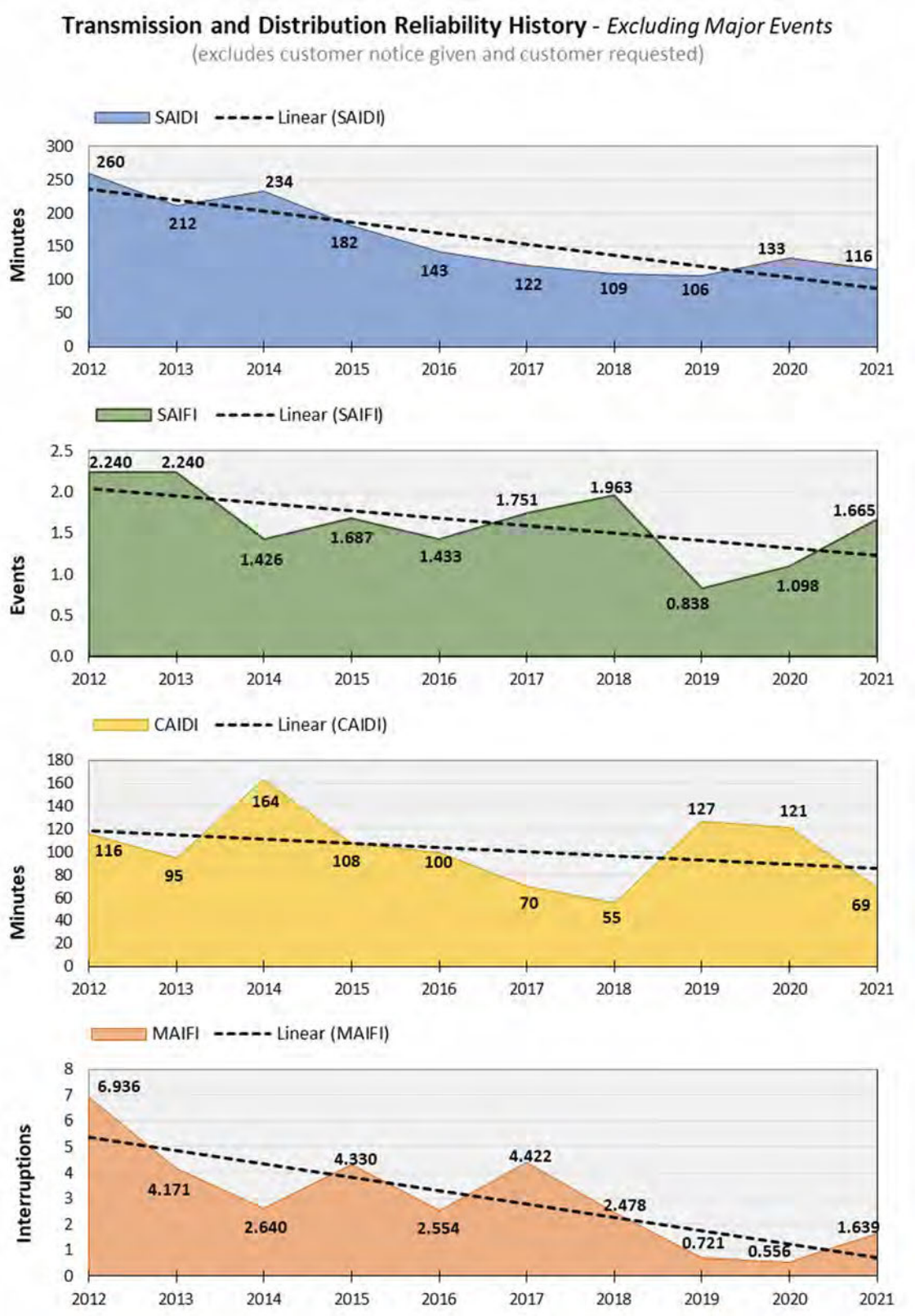
Notes:

1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.


Transmission and Distribution Reliability History - Including Major Events
(excludes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
800
700
600
500
400
300
200
100
0
502
317
430
528
219
691
292
590
381
441
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
SAIFI
Linear (SAIFI)
Events
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.990
2.857
1.978
2.934
1.915
3.671
2.841
3.048
1.702
3.886
CAIDI
Linear (CAIDI)
Minutes
250
200
150
100
50
0
168
111
217
180
114
188
103
193
224
114
MAIFI
Linear (MAIFI)
Interruptions
8
7
6
5
4
3
2
1
0
6.936
4.171
2.640
4.330
2.554
4.422
2.478
0.721
0.556
1.639


Transmission and Distribution Reliability History - Excluding Major Events
(excludes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
260
212
234
182
143
122
109
106
133
116
SAIFI
Linear (SAIFI)
Events
2.240
2.240
1.426
1.687
1.433
1.751
1.963
0.838
1.098
1.665
CAIDI
Linear (CAIDI)
Minutes
116
95
164
108
100
70
55
127
121
69
MAIFI
Linear (MAIFI)
Interruptions
6.936
4.171
2.640
4.330
2.554
4.422
2.478
0.721
0.556
1.639
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

District Reliability Underlying Indices - Excluding Planned Outages: Ten-Year SAIDI, SAIFI and CAIDI Results

Crescent City

Crescent City - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	637.6	5.209	122	4.375	112.4	1.596	70	4.375
2020	199.6	1.600	125	0	115.3	1.166	99	0.0
2019	1291.0	4.105	314	0	96.4	0.881	109	0.0
2018	600.7	6.847	88	0	104.6	3.607	29	0.0
2017	1027.6	4.792	214	0	124.6	1.178	106	0.0
2016	343.7	2.644	130	0	161.6	1.431	113	0.0
2015	949.5	2.495	381	2.482	96.7	0.776	125	2.482
2014	846.7	2.967	285	0	318.2	1.592	200	0
2013	105.4	0.615	171	0	105.4	0.615	171	0
2012	453.0	4.115	110	0	391.4	3.770	104	0

Notes:

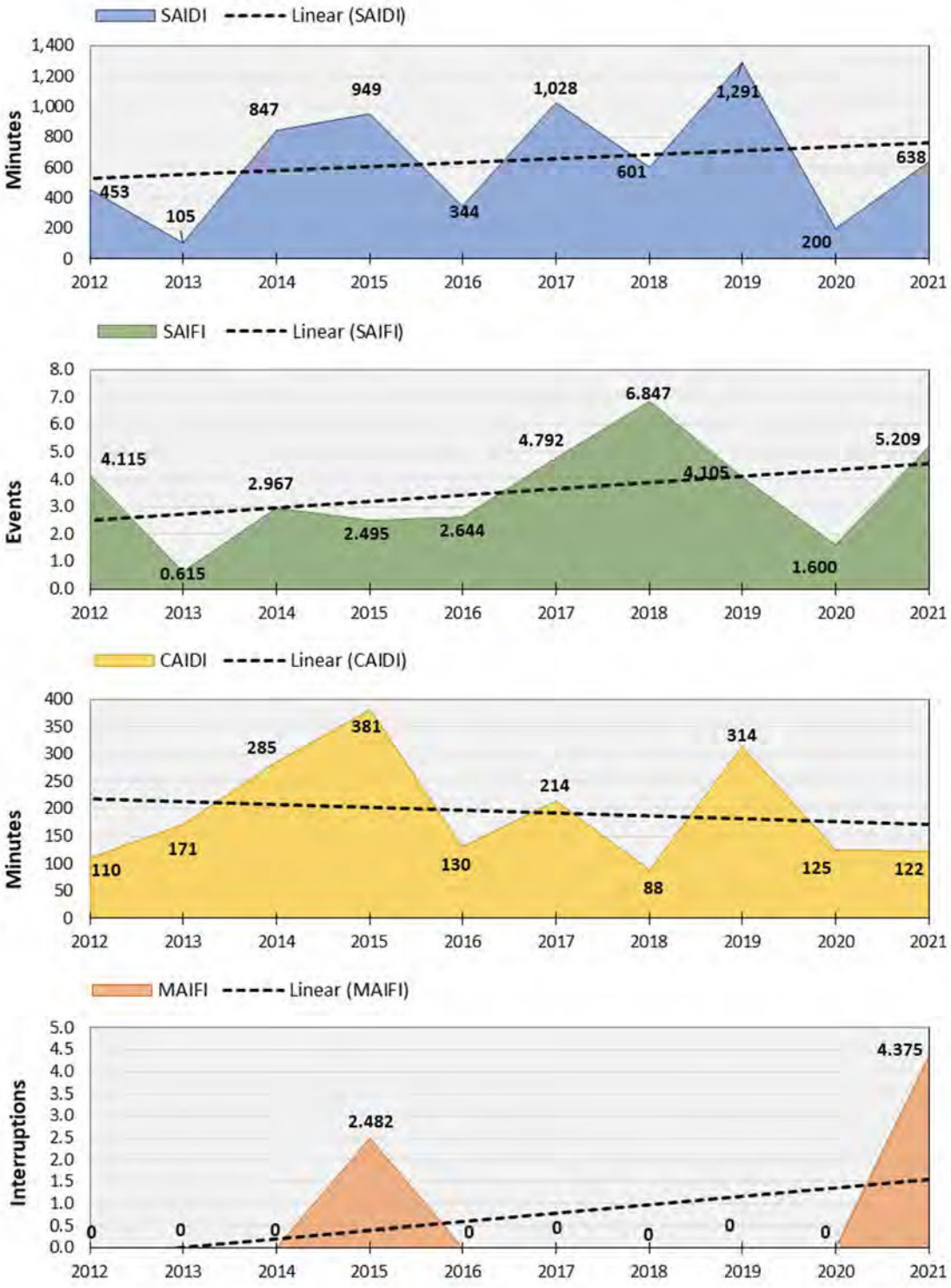
1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

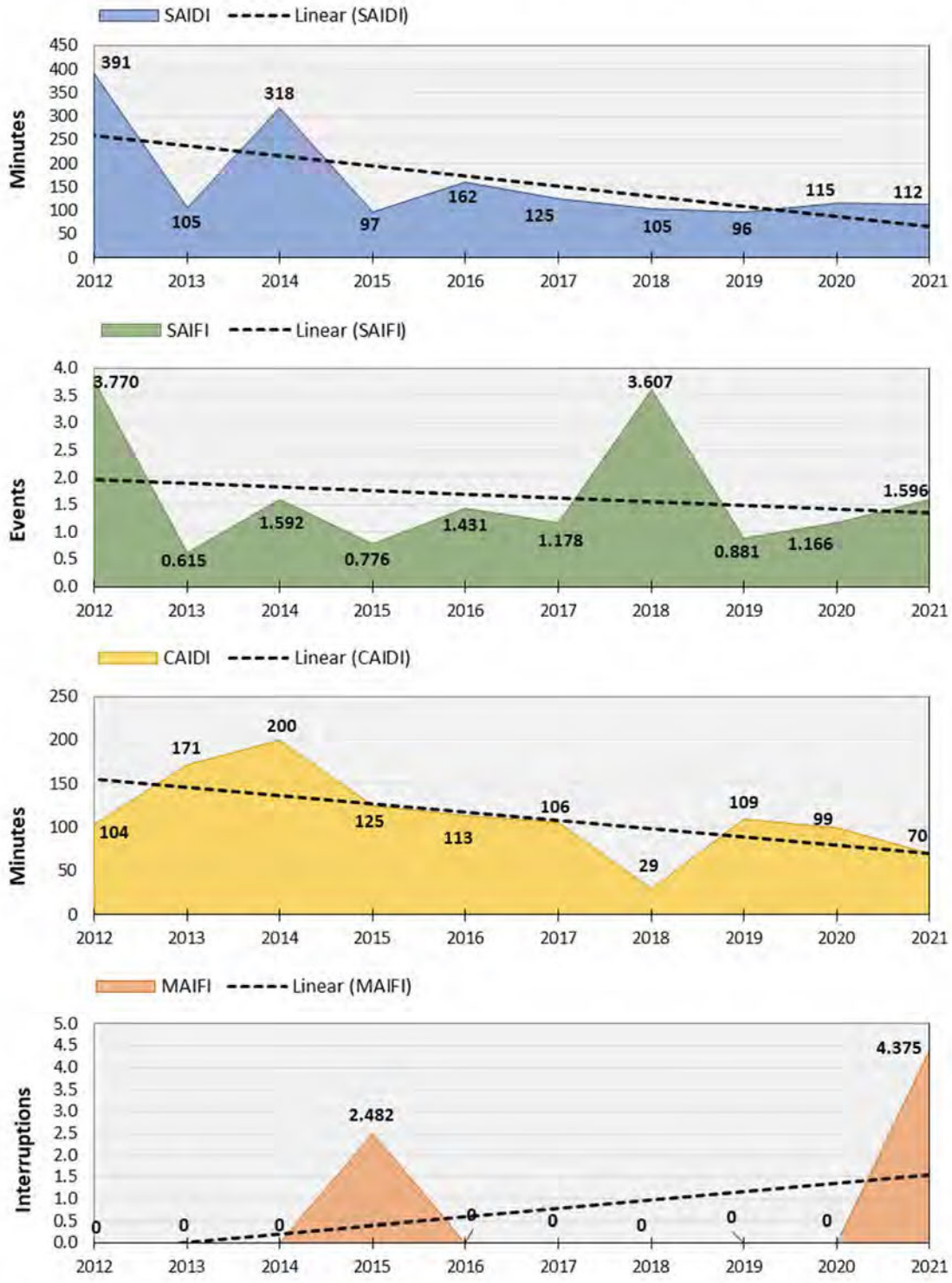
Crescent City Reliability History - *Including Major Events*

(excludes customer notice given and customer requested)



Crescent City Reliability History - *Excluding Major Events*

(excludes customer notice given and customer requested)



Yreka/Mt. Shasta

Yreka/Mt. Shasta - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	393.5	3.601	109	0.684	124.2	1.776	70	0.684
2020	515.2	1.853	278	0.096	137.9	1.070	129	0.096
2019	379.9	3.044	125	1.096	116.9	0.784	149	1.096
2018	190.5	1.289	148	2.329	106.5	1.283	83	2.329
2017	648.0	3.259	199	3.459	121.8	1.905	64	3.459
2016	184.6	1.689	109	1.923	146.4	1.455	101	1.923
2015	349.2	3.188	110	4.328	230.3	2.290	101	4.328
2014	303.0	1.738	174	2.666	222.0	1.437	155	2.666
2013	409.8	3.847	107	4.042	231.3	2.821	82	4.042
2012	616.1	2.967	208	7.268	228.1	1.838	124	7.268

Notes:

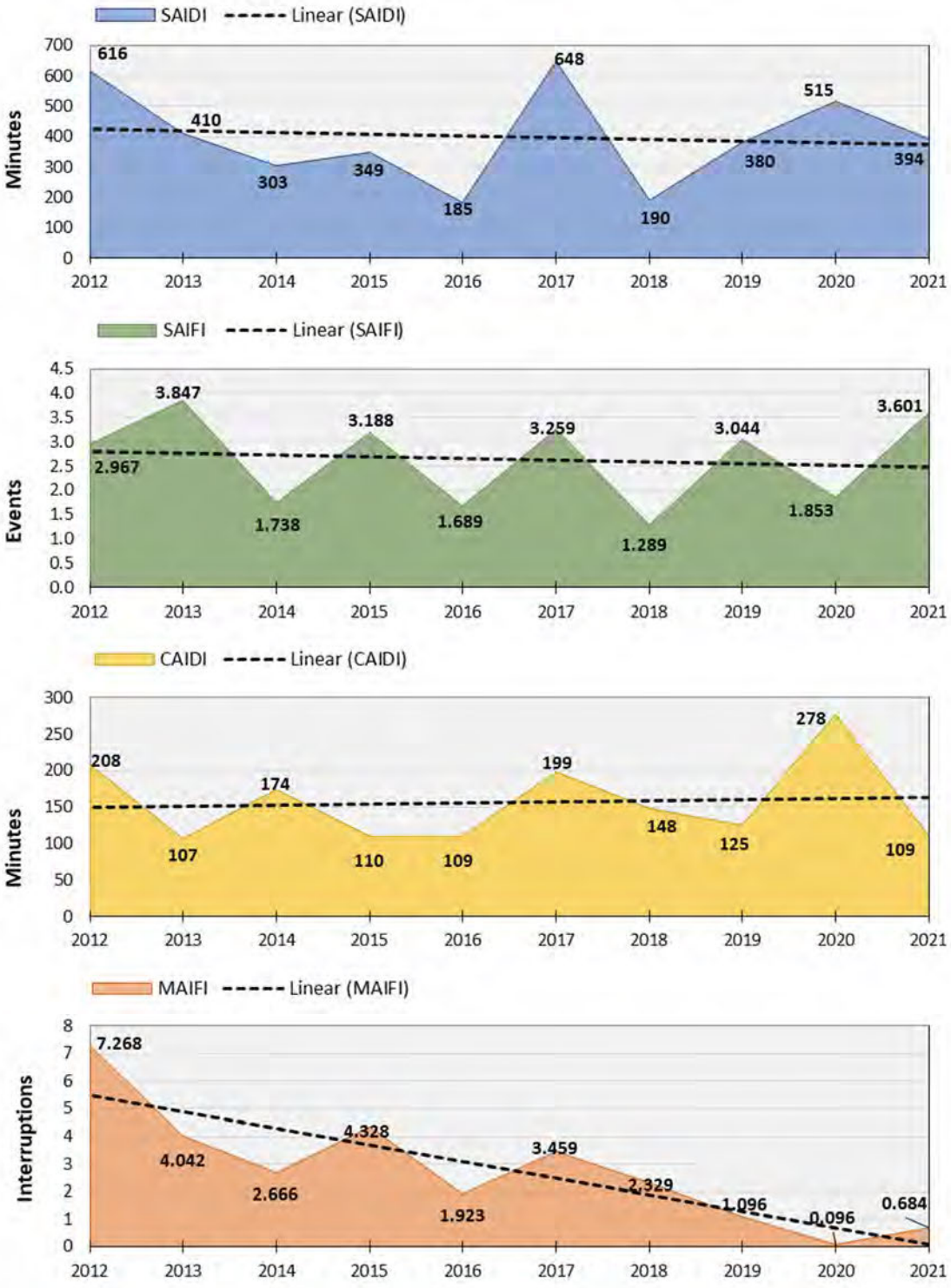
1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

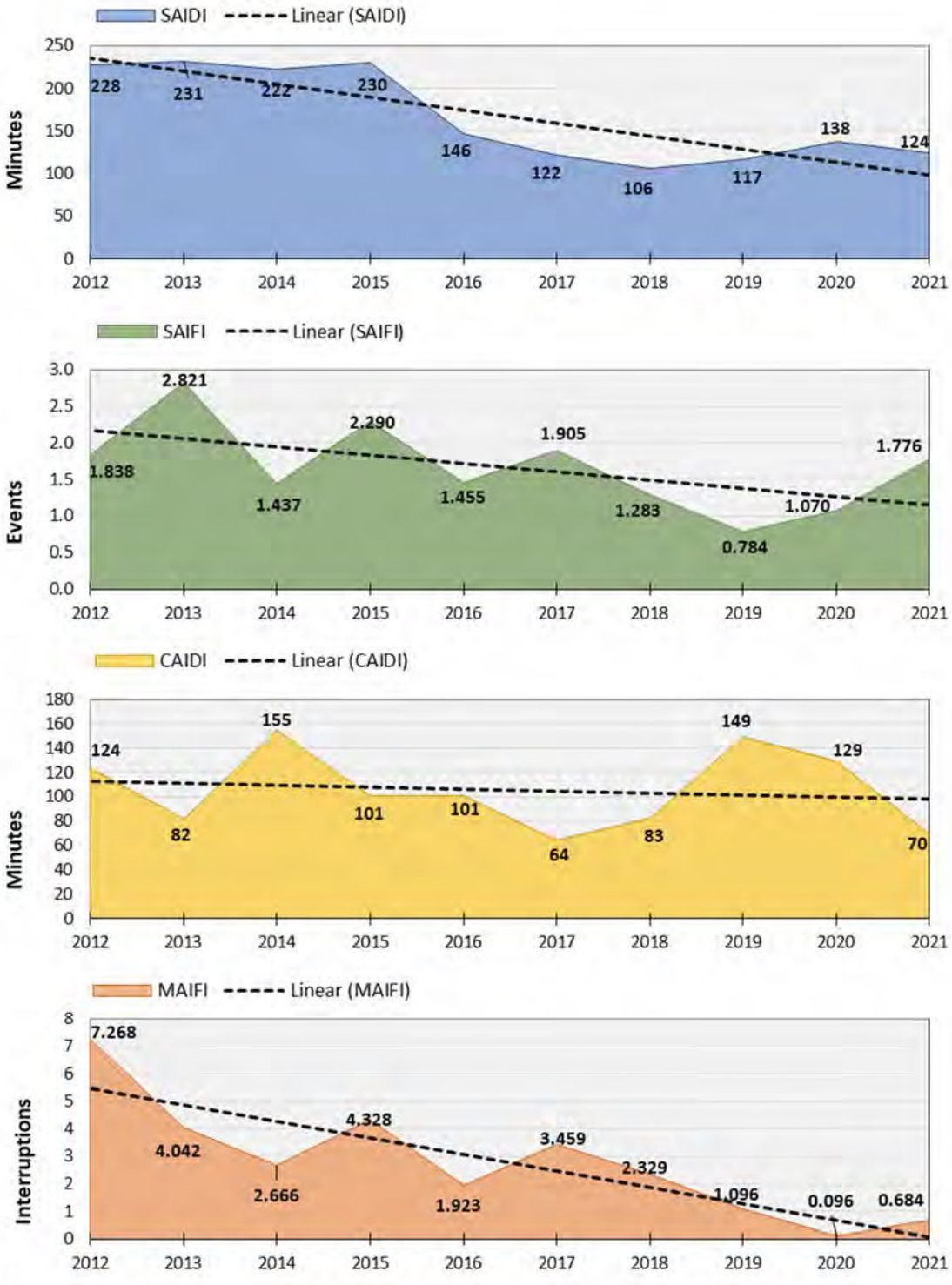
Yreka/Mt. Shasta Reliability History - *Including Major Events*

(excludes customer notice given and customer requested)



Yreka/Mt. Shasta Reliability History - *Excluding Major Events*

(excludes customer notice given and customer requested)



Tulelake/Alturas

Tulelake/Alturas - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	262.0	2.534	103	0.328	86.8	1.343	65	0.328
2020	178.2	1.274	140	0.116	146.4	1.079	136	0.116
2019	132.4	1.079	123	3.000	81.6	0.978	83	3.000
2018	128.4	1.667	77	5.133	127.0	1.658	77	5.133
2017	235.5	3.248	72	16.151	119.3	2.198	54	16.151
2016	128.7	1.518	85	9.386	95.3	1.389	69	9.386
2015	462.3	2.739	169	5.237	147.1	0.978	150	5.237
2014	171.2	1.126	152	4.755	125.0	1.083	115	4.755
2013	341.4	3.067	111	8.754	329.6	2.925	113	8.754
2012	142.7	1.033	138	10.761	142.7	1.033	138	10.761

Notes:

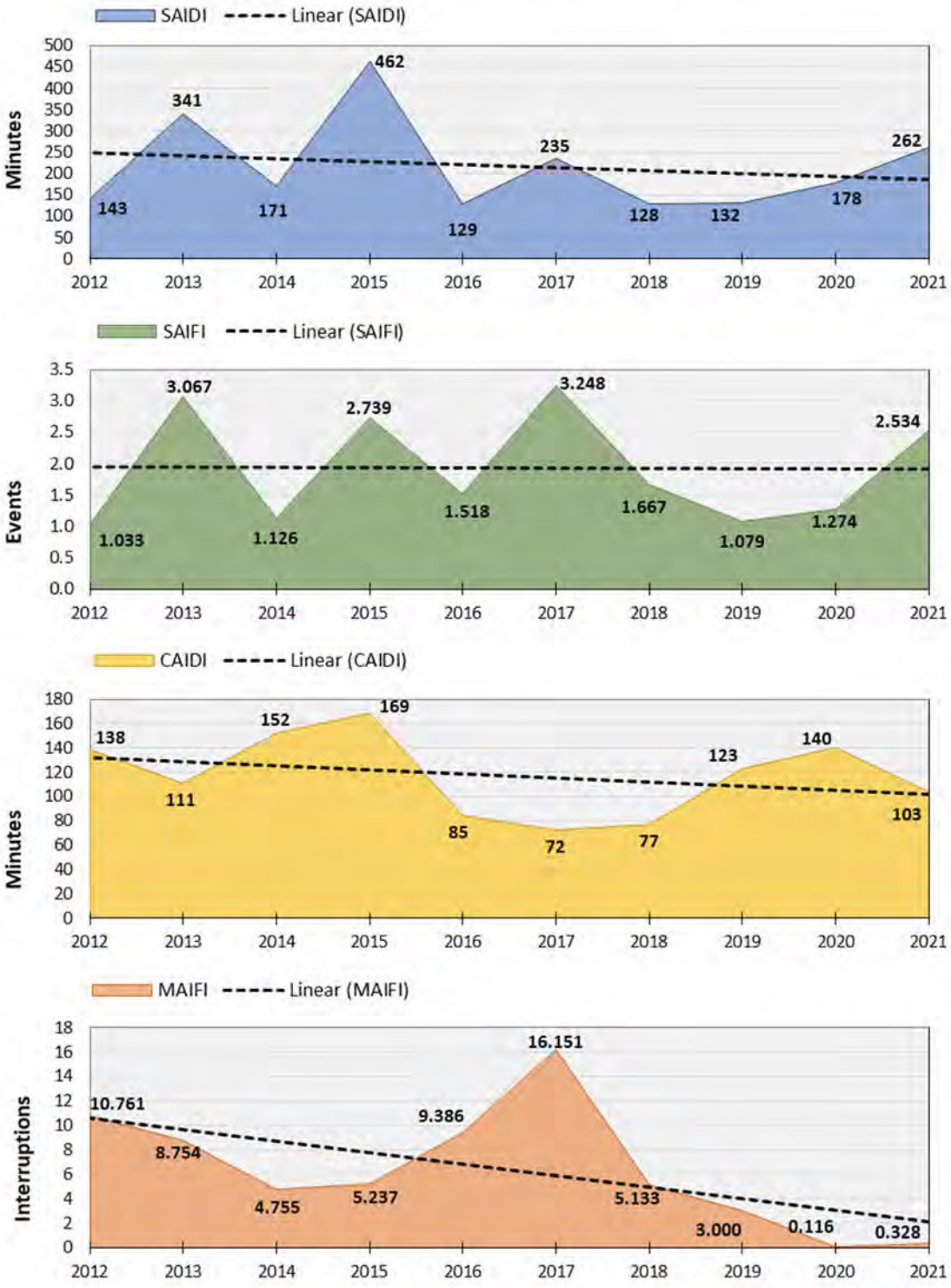
1 - Excludes outages that are customer requested, pre-arranged, extended a result of "Elevated Fire Risk" settings, or resulting from a failure of another company's system.

2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going - forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

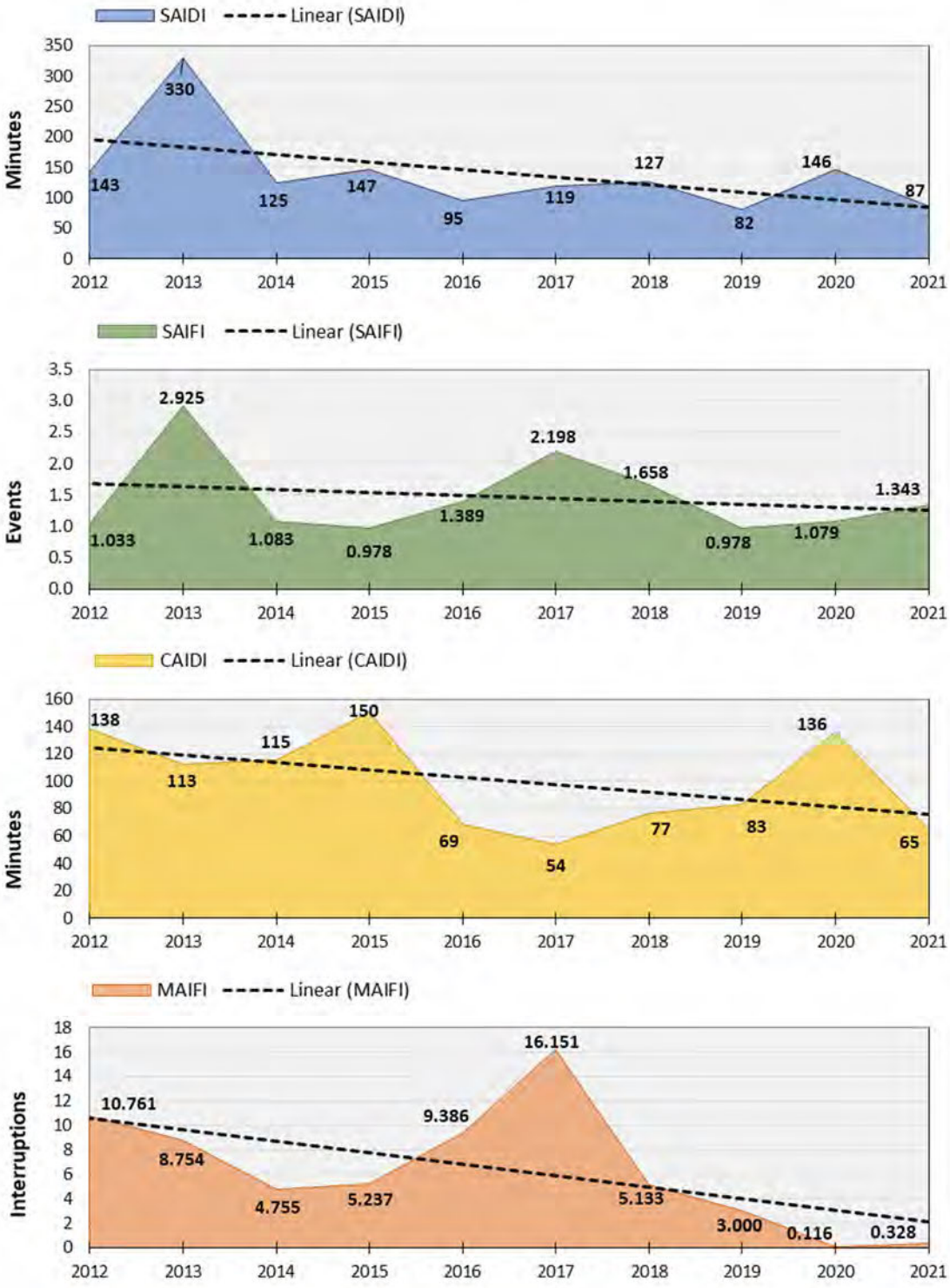
Tulelake/Alturas Reliability History - *Including Major Events*

(excludes customer notice given and customer requested)



Tulelake/Alturas Reliability History - *Excluding Major Events*

(excludes customer notice given and customer requested)



State and District Reliability Underlying Indices - Including Planned Outages: Ten-Year Year SAIDI, SAIFI and CAIDI Results

State

State - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	621.1	4.783	130	1.639	284.2	2.514	113	1.639
2020	436.3	1.962	222	0.556	185.4	1.353	137	0.556
2019	656.1	3.331	197	0.721	172.7	1.118	154	0.721
2018	366.8	3.004	122	2.478	183.6	2.126	86	2.478
2017	727.6	3.936	185	4.422	158.7	2.014	79	4.422
2016	273.8	2.179	126	2.554	197.6	1.697	116	2.554
2015	554.5	3.042	182	4.330	208.6	1.795	116	4.330
2014	455.4	2.107	216	2.640	259.0	1.554	167	2.640
2013	344.6	2.959	116	4.171	239.1	2.342	102	4.171
2012	512.9	3.046	168	6.936	270.7	2.296	118	6.936

Notes:

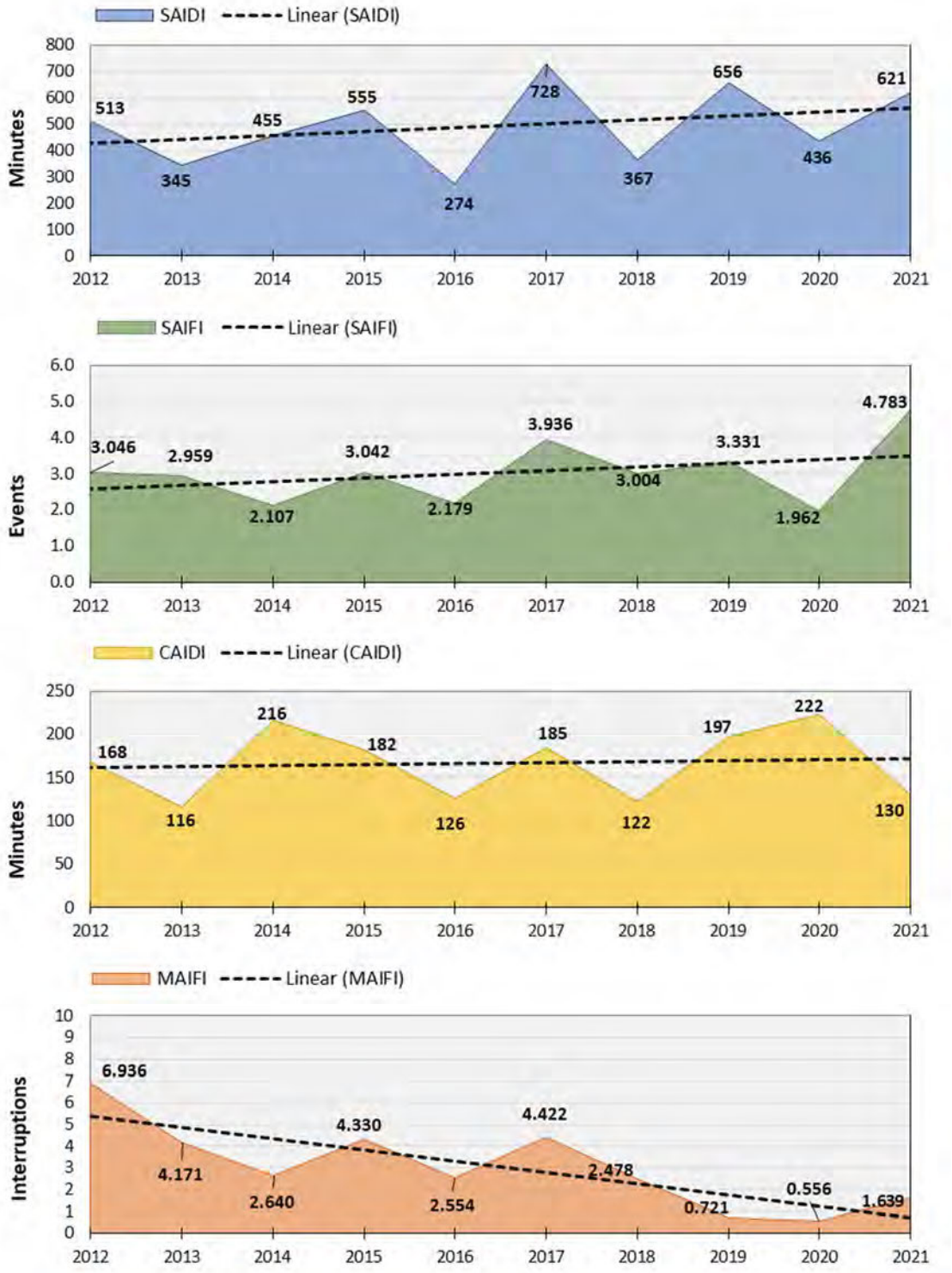
1 - Includes outages that are customer requested, pre-arranged (which can include short notice emergency prearranged outages), extended as a result of "Elevated Fire Risk" settings, forced outages mandated by public authority, or resulting from a failure of another company's system.

2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going -forward.

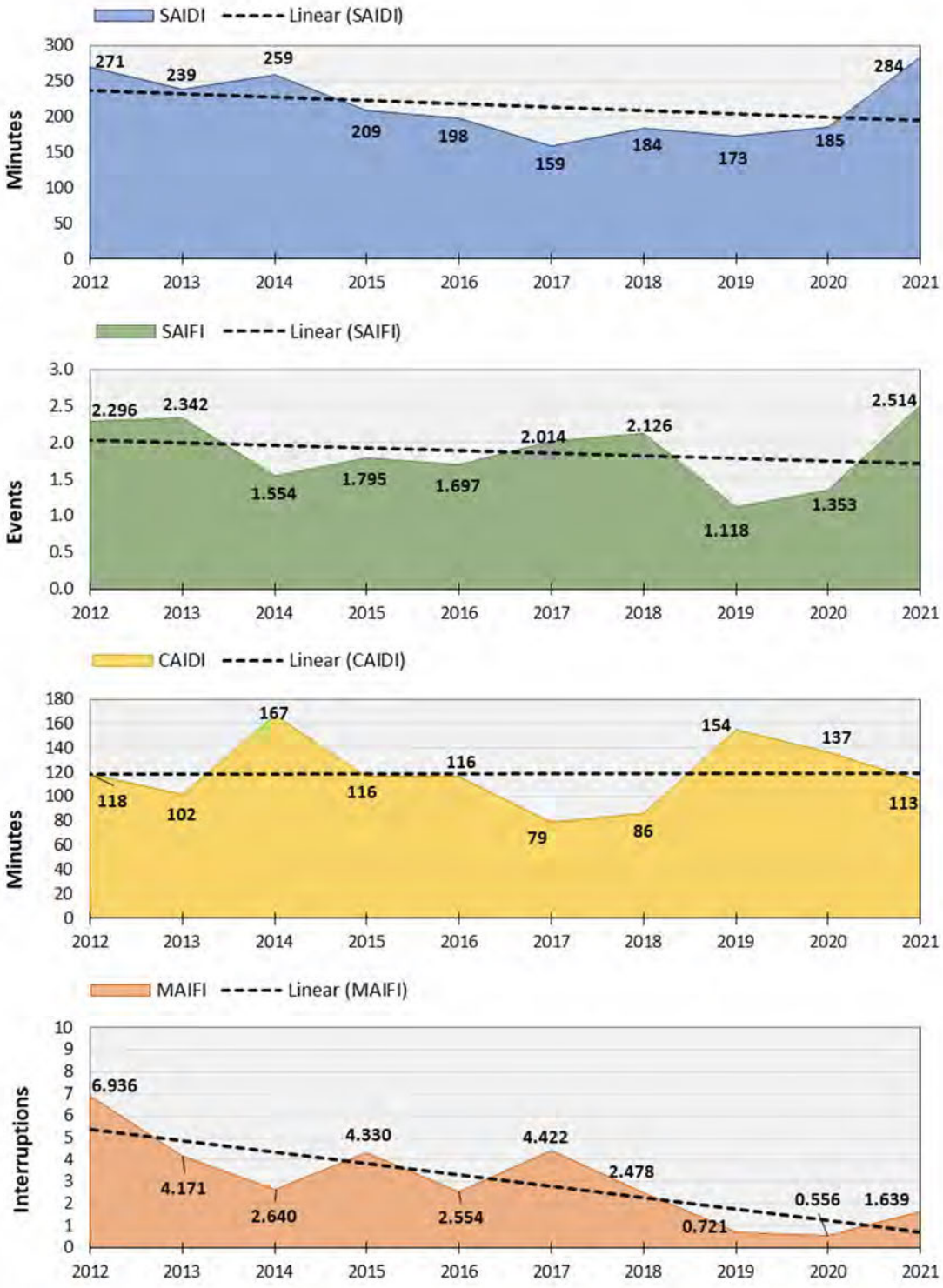
3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

State Reliability History - *Including Major Events*

(includes customer notice given and customer requested)



State Reliability History - *Excluding Major Events*
(includes customer notice given and customer requested)



Crescent City

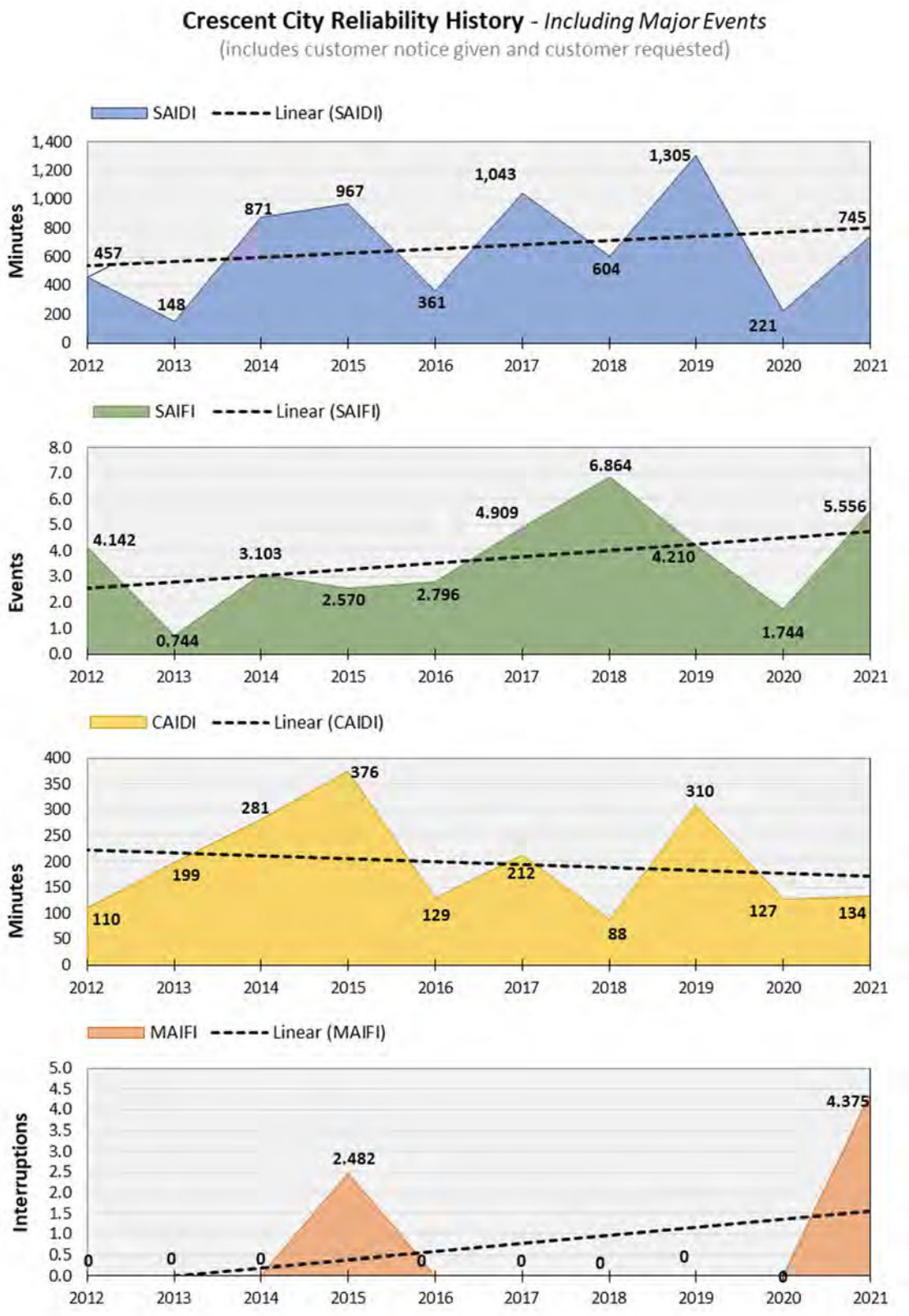
Crescent City - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	744.9	5.556	134	4.375	219.6	1.943	113	4.375
2020	221.1	1.744	127	0	136.8	1.311	104	0
2019	1304.9	4.210	310	0	110.2	0.985	112	0
2018	603.6	6.864	88	0	107.6	3.624	30	0
2017	1042.6	4.909	212	0	139.4	1.294	108	0
2016	361.4	2.796	129	0	179.2	1.583	113	0
2015	966.9	2.570	376	2.482	114.0	0.851	134	2.482
2014	871.1	3.103	281	0	342.6	1.728	198	0
2013	147.7	0.744	199	0	147.7	0.743	199	0
2012	457.4	4.142	110	0	395.8	3.797	104	0

Notes:

1 - Includes outages that are customer requested, pre-arranged (which can include short notice emergency prearranged outages), extended as a result of "Elevated Fire Risk" settings, forced outages mandated by public authority, or resulting from a failure of another company's system.

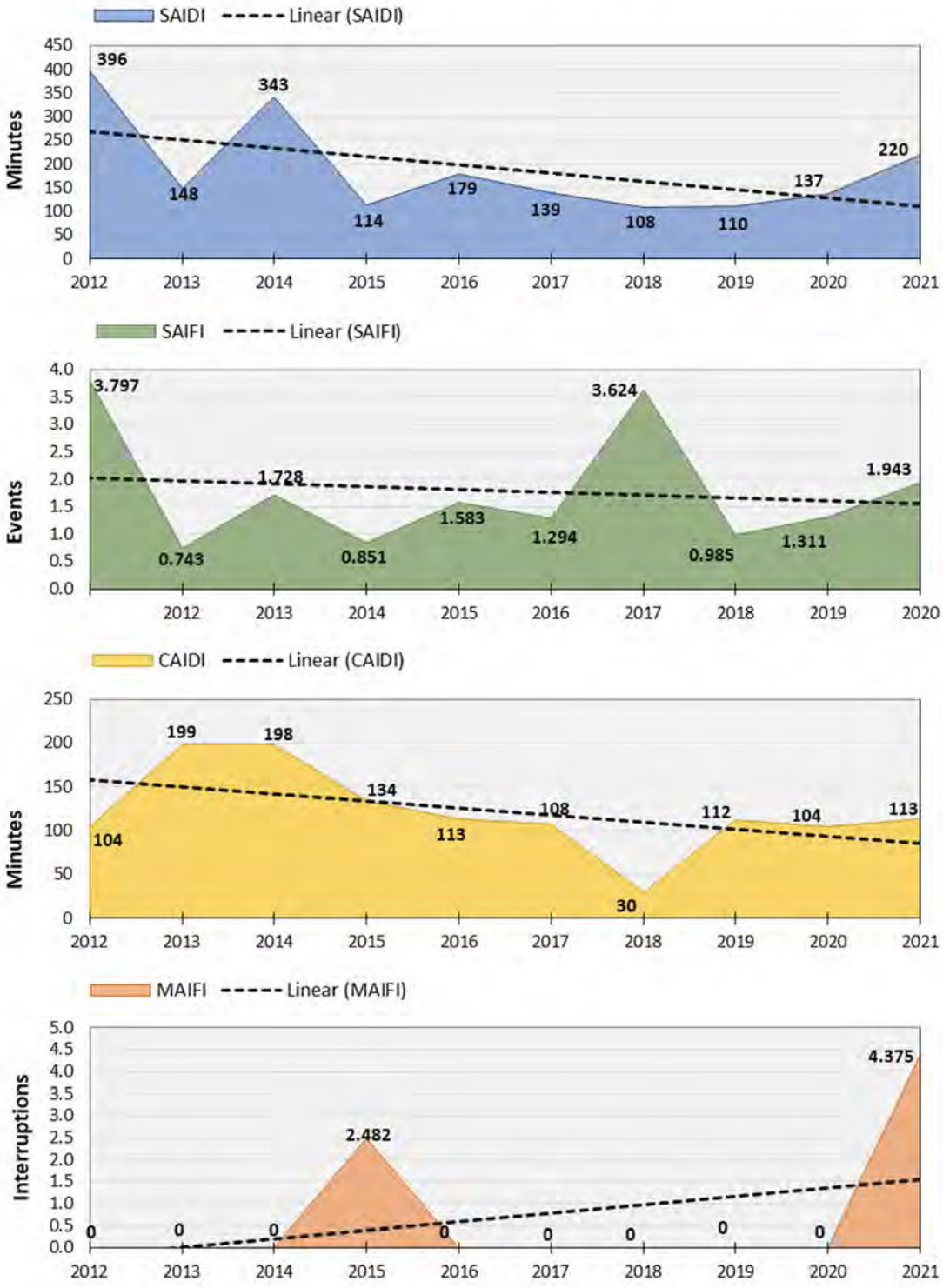
2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going -forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.


Crescent City Reliability History - Including Major Events
(includes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
1,400
1,200
1,000
800
600
400
200
0
457
148
871
967
361
1,043
604
1,305
221
745
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
SAIFI
Linear (SAIFI)
Events
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
4.142
0.744
3.103
2.570
2.796
4.909
6.864
4.210
1.744
5.556
CAIDI
Linear (CAIDI)
Minutes
400
350
300
250
200
150
100
50
0
110
199
281
376
129
212
88
310
127
134
MAIFI
Linear (MAIFI)
Interruptions
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
0
0
2.482
0
0
0
0
0
4.375

Crescent City Reliability History - *Excluding Major Events*

(includes customer notice given and customer requested)



Yreka/Mt. Shasta

Yreka/Mt. Shasta - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	614.0	4.902	125	0.684	325.2	2.995	109	0.684
2020	597.5	2.199	272	0.096	216.2	1.409	153	0.096
2019	469.2	3.392	138	1.096	206.2	1.131	182	1.096
2018	313.5	1.520	206	2.329	229.5	1.514	152	2.329
2017	699.9	3.586	195	3.459	173.5	2.231	78	3.459
2016	270.3	2.069	131	1.923	232.2	1.836	126	1.923
2015	382.2	3.325	115	4.328	263.2	2.427	108	4.328
2014	332.6	1.842	181	2.666	251.7	1.540	163	2.666
2013	422.0	3.911	108	4.042	243.5	2.885	84	4.042
2012	633.1	3.048	208	7.268	244.9	1.919	128	7.268

Notes:

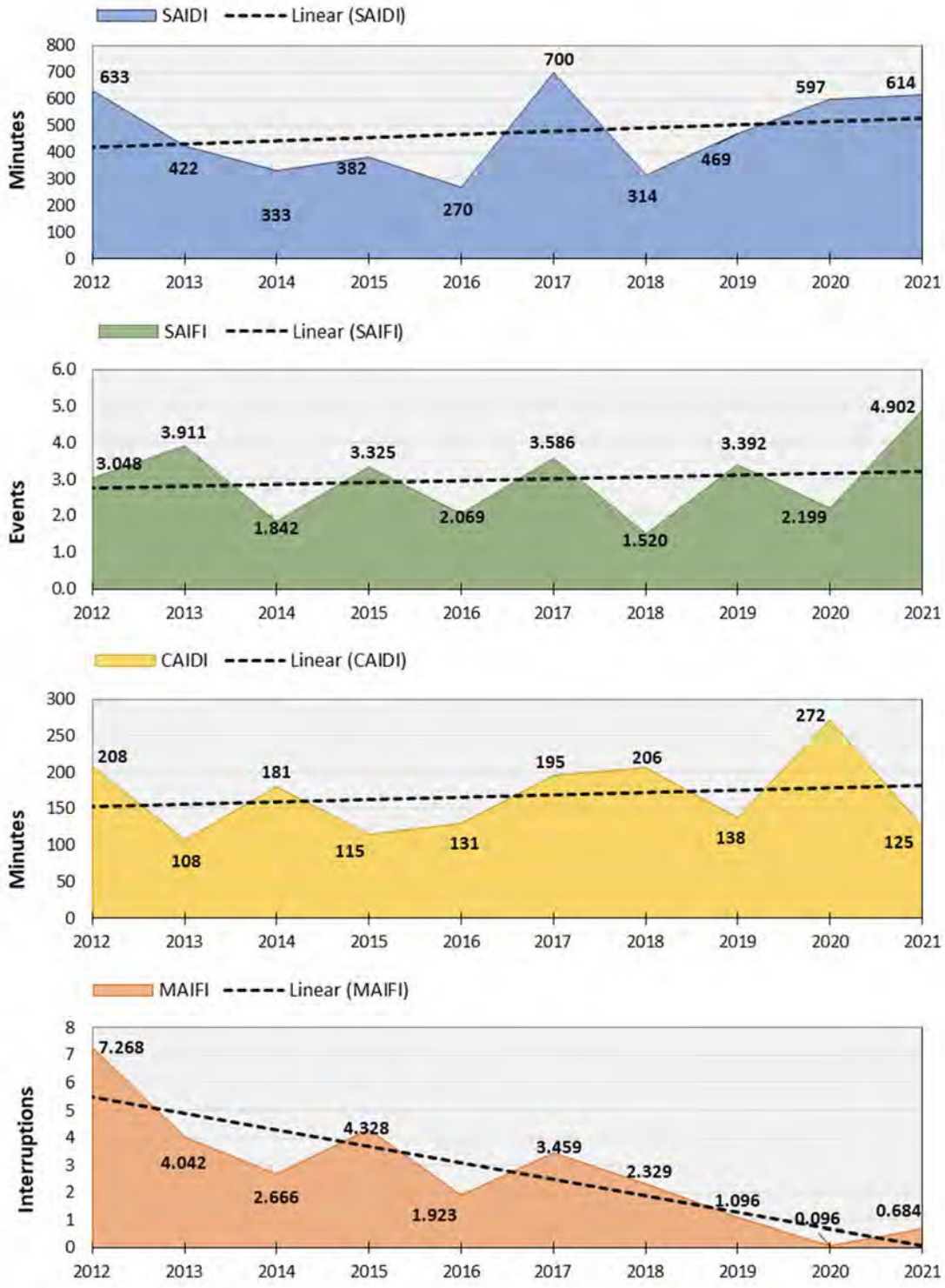
1 - Includes outages that are customer requested, pre-arranged (which can include short notice emergency prearranged outages), extended as a result of "Elevated Fire Risk" settings, forced outages mandated by public authority, or resulting from a failure of another company's system.

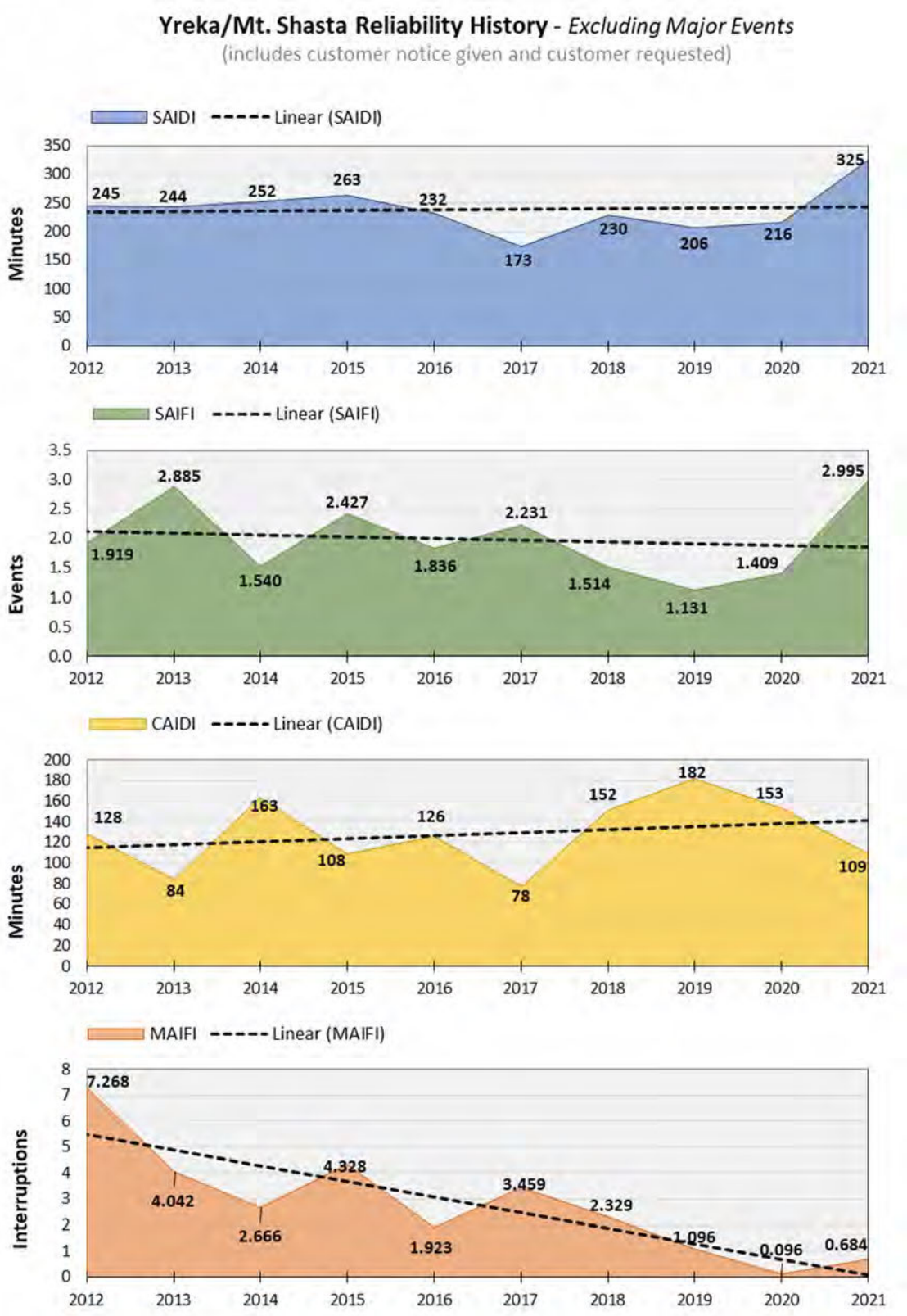
2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going -forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

Yreka/Mt. Shasta Reliability History - *Including Major Events*

(includes customer notice given and customer requested)




Yreka/Mt. Shasta Reliability History - Excluding Major Events
(includes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
245
244
252
263
232
173
230
206
216
325
SAIFI
Linear (SAIFI)
Events
1.919
2.885
1.540
2.427
1.836
2.231
1.514
1.131
1.409
2.995
CAIDI
Linear (CAIDI)
Minutes
128
84
163
108
126
78
152
182
153
109
MAIFI
Linear (MAIFI)
Interruptions
7.268
4.042
2.666
4.328
1.923
3.459
2.329
1.096
0.096
0.684
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

Tulelake/Alturas

Tulelake/Alturas - District System Indices								
	Major Events Included[1]				Major Events Excluded[2] (2.5 ß P1366)			
Year	SAIDI	SAIFI	CAIDI	MAIFI[3]	SAIDI	SAIFI	CAIDI	MAIFI[3]
2021	415.0	2.834	146	0.328	239.7	1.640	146	0.328
2020	184.0	1.396	132	0.116	152.2	1.202	127	0.116
2019	204.2	1.433	142	3.000	153.2	1.313	117	3.000
2018	140.0	1.822	77	5.133	138.7	1.813	76	5.133
2017	251.0	3.534	71	16.151	158.7	2.014	79	16.151
2016	128.9	1.519	85	9.386	95.5	1.390	69	9.386
2015	481.1	2.794	172	5.237	165.9	1.033	161	5.237
2014	182.3	1.338	136	4.755	136.0	1.295	105	4.755
2013	399.7	3.263	123	8.754	388.1	3.123	124	8.754
2012	143.1	1.035	138	10.761	143.0	1.034	138	10.761

Notes:

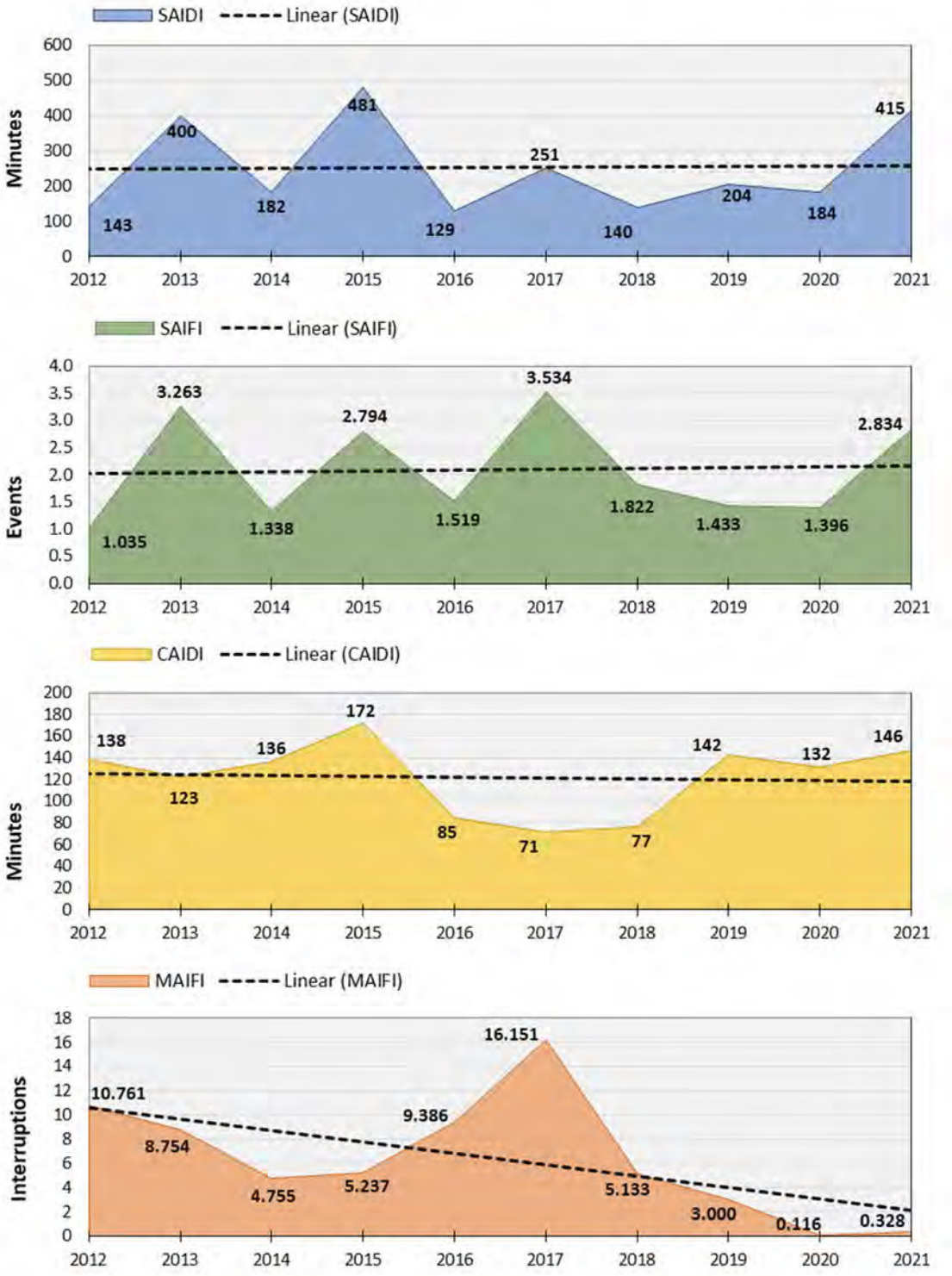
1 - Includes outages that are customer requested, pre-arranged (which can include short notice emergency prearranged outages), extended as a result of "Elevated Fire Risk" settings, forced outages mandated by public authority, or resulting from a failure of another company's system.

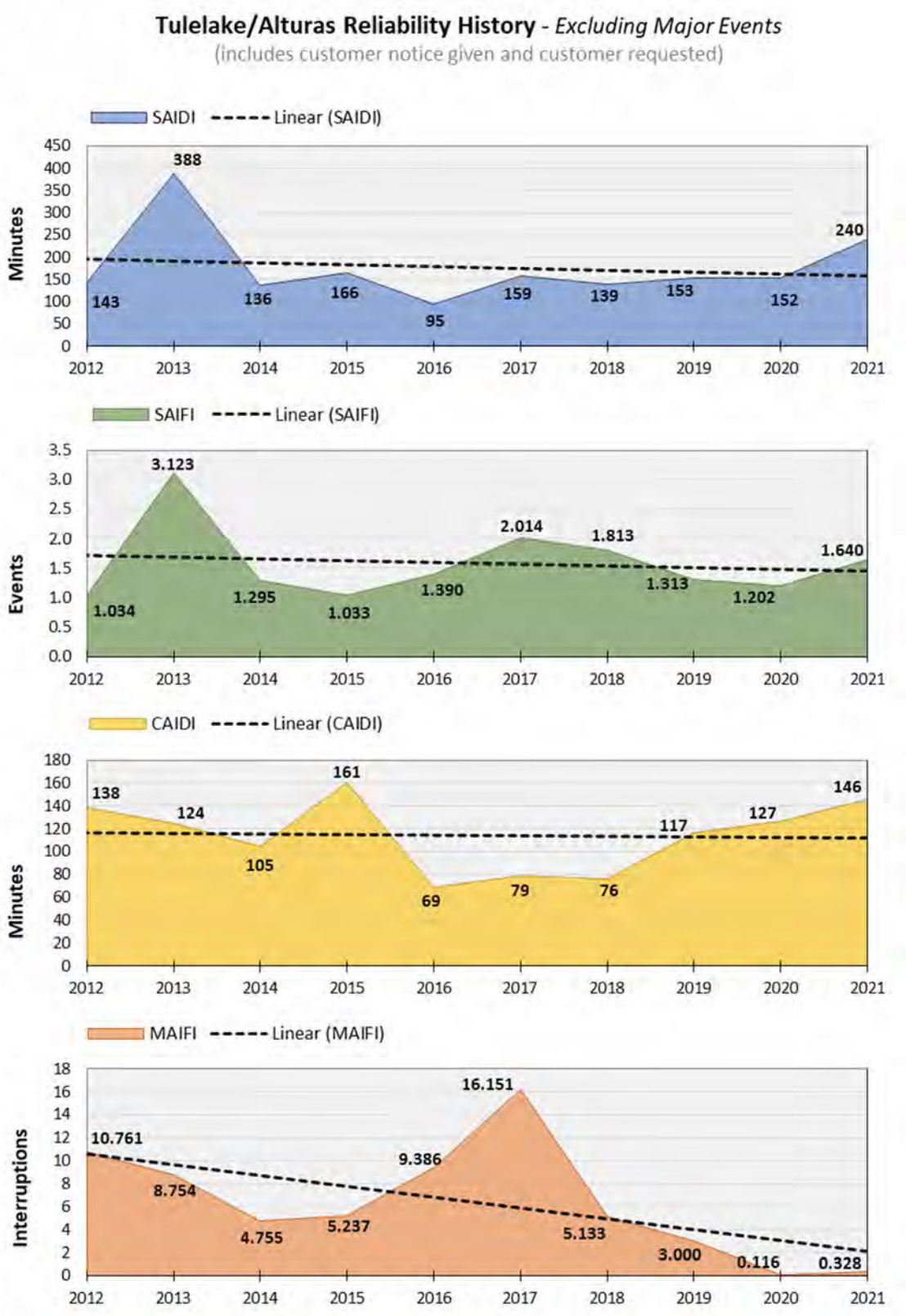
2 - In 2016, D.16-01-008 approved Major Event designation process. 2015 Local events were reviewed and are excluded from the indices going -forward.

3 - Momentary indices are reported within distribution system metrics and are inclusive of outages that occurred during major events.

Tulelake/Alturas Reliability History - *Including Major Events*

(includes customer notice given and customer requested)




Tulelake/Alturas Reliability History - Excluding Major Events
(includes customer notice given and customer requested)
SAIDI
Linear (SAIDI)
Minutes
388
143
136
166
95
159
139
153
152
240
SAIFI
Linear (SAIFI)
Events
3.123
1.034
1.295
1.033
1.390
2.014
1.813
1.313
1.202
1.640
CAIDI
Linear (CAIDI)
Minutes
138
124
105
161
69
79
76
117
127
146
MAIFI
Linear (MAIFI)
Interruptions
10.761
8.754
4.755
5.237
9.386
16.151
5.133
3.000
0.116
0.328
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

Planned Outage by District

The below table shows planned outage events which occurred annually, by district and month.

Planned Outages[1]				
		Crescent City	Tulelake/ Alturas	Yreka/ Mt. Shasta
2021	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2020	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2019	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			

Planned Outages[1]				
		Crescent City	Tulelake/ Alturas	Yreka/ Mt. Shasta
2018	January	[redacted]		
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2017	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2016	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2015	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			

Planned Outages[1]				
		Crescent City	Tulelake/ Alturas	Yreka/ Mt. Shasta
2014	January	[redacted]		
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2013	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
2012	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			

1 - Includes outages that are customer requested, pre-arranged (which can include short notice emergency prearranged outages), forced outages mandated by public authority, or resulting from a failure of another company's system.

Top Ten Unplanned Power Outage Events for 2021

The table below displays the top 10 unplanned outages in 2021 based on the total customer minutes lost.

Top 10 Unplanned Outage Events – 2021					
Date	**District**	**Description**	**Major Event?**	**Total Customer Minutes Lost**	**Total Customers in Incident**
12/15/2021	Yreka/Mt. Shasta	Loss of Transmission Line	Y	1,867,049	1,037
1/12/2021	Crescent City	Loss of Transmission Line	Y	632,979	422
11/8/2021	Crescent City	Loss of Transmission Line	Y	606,242	420
8/23/2021	Yreka/Mt. Shasta	Loss of Transmission Line	Y	511,264	2,458
8/17/2021	Yreka/Mt. Shasta	Unknown trip	N	504,876	1,901
1/12/2021	Crescent City	Loss of Transmission Line	Y	496,483	331
12/13/2021	Crescent City	Loss of Transmission Line	Y	488,632	421
11/8/2021	Crescent City	Loss of Transmission Line	Y	480,663	333
12/25/2021	Yreka/Mt. Shasta	Loss of Transmission Line	N	436,161	579
12/15/2021	Yreka/Mt. Shasta	Loss of Transmission Line	Y	428,131	2,766

Major Event Summary

PacifiCorp's service territory in California consists of the three operating areas: Crescent City, Yreka/Mt. Shasta, and Tulelake/Alturas. Each operating area has been designated as a reliability reporting region in accordance with the Order. Each year the major event threshold for the state is determined using the t_{Med} methodology, as defined in IEEE P1366 and known as the "2.5 beta" method. The state t_{Med} is then applied to each operating area[8]. The table below depicts the major events which have occurred during 2021.

2021 Major Event Summary

Date	District	Cause	Customers out for a duration of:					
			5 min - 3 hrs.	3 - 24 hrs.	24 - 48 hrs.	48 - 72 hrs.	72 - 96 hrs.	96 + hrs.
January 3, 2021	Tulelake/ Alturas	Loss of Substation	1,305	-	1,305	-	-	-
January 12-13, 2021	California (State)	Loss of Transmission Line	1,538	647	138	753	-	-
January 26-28, 2021	California (State)	Loss of Substation	26,846	25,361	1,485	-	-	-
February 19, 2021	Crescent City	Landslide	761	6	755	-	-	-
February 25-27, 2021	Yreka/Mt Shasta	Loss of Transmission line and Damaged Equipment	7,717	5,726	1,991	-	-	-
March 5, 2021	Crescent City	Loss of Transmission line and Damaged Equipment	3,723	2,507	1,216	-	-	-
June 22, 2021	Tulelake/ Alturas	Loss of Transmission line and Damaged Equipment	5,240	5,240	-	-	-	-
July 4-5, 2021	Yreka/Mt Shasta	Loss of Transmission line	5,612	4,663	949	-	-	-
August 23-24, 2021	California (State)	Loss of Transmission line	10,081	4,319	5,762	-	-	-
November 8-9,2021	California (State)	Tree and wind outages	4,201	2,651	797	753	-	-
November 13-14, 2021	Tulelake/ Alturas	loss of transmission line due to car hit pole	1,137	817	320	-	-	-
December 12-14, 2021	California (State)	Loss of Substation	12,474	11,709	765	-	-	-
December 15-17, 2021	California (State)	Loss of Transmission line Snowstorm	25,804	23,822	828	1,060	94	-

[8] Due to the size and irregularity of outage occurrences by district, it was deemed appropriate to apply the state t_{Med} to each district, in an attempt to better adhere to major event standards throughout the operating areas and state.

Historical Top Ten Unplanned Power Outage Events – 2020 through 2011

Historical Top Ten Unplanned Outage Events by Year						
Year	**Date**	**District**	**Description**	**Excluded Major Event?**	**Total Customer Minutes Lost**	**Total Customers in Incident**
2020	9/8/2020	Yreka/Mt. Shasta	Wildfire	Y	5,561,782	767
	1/16/2020	Yreka/Mt. Shasta	Loss of Transmission Line	Y	789,985	1,849
	9/15/2020	Yreka/Mt. Shasta	Loss of Generation	Y	601,739	548
	11/7/2020	Yreka/Mt. Shasta	Loss of Transmission Line	N	461,489	1,039
	1/16/2020	Yreka/Mt. Shasta	Loss of Transmission Line	Y	436,087	753
	1/25/2020	Crescent City	Loss of Transmission Line	N	212,370	761
	8/15/2020	Yreka/Mt. Shasta	Loss of Transmission Line	Y	197,690	1,419
	11/17/2020	Yreka/Mt. Shasta	Damaged Equipment	N	195,925	1,186
	1/16/2020	Yreka/Mt. Shasta	Wind Blown Tree	Y	177,667	48
	5/21/2020	Crescent City	Damaged Equipment	N	174,198	2,294
2019	11/26/2019	Crescent City	Wildfire	Y	1,135,268	1,447
	11/26/2019	Crescent City	Loss of Substation	Y	870,310	1,342
	1/17/2019	Crescent City	Loss of Substation	Y	767,461	424
	11/26/2019	Crescent City	Wildfire	Y	759,630	1,277
	11/26/2019	Crescent City	Wildfire	Y	692,294	1,011
	11/26/2019	Crescent City	Loss of Substation	Y	601,838	513
	2/25/2019	Yreka/Mt Shasta	Loss of Substation	Y	527,481	2,458
	11/26/2019	Crescent City	Loss of Substation	Y	451,861	1,185
	2/9/2019	Crescent City	Loss of Transmission Line	Y	442,539	472
	11/26/2019	Crescent City	Loss of Transmission Line	Y	420,843	862
2018	9/5/2018	Yreka/Mt Shasta	Wildfire	Y	1,317,536	140
	11/23/2018	Crescent City	Loss of Substation	Y	604,033	2,230
	11/22/2018	Crescent City	Loss of Substation	Y	589,598	3,723
	9/5/2018	Yreka/Mt Shasta	Wildfire	Y	516,658	290
	9/5/2018	Yreka/Mt Shasta	Wildfire	Y	464,656	76
	11/23/2018	Crescent City	Loss of Substation	Y	453,669	1,672
	11/23/2018	Crescent City	Loss of Substation	Y	392,788	1,447
	11/23/2018	Crescent City	Loss of Substation	Y	364,652	1,345
	11/23/2018	Crescent City	Loss of Transmission Line	Y	276,210	1,023
	12/14/2018	Crescent City	Loss of Transmission Line	Y	271,134	424
2017	1/18/2017	Yreka/Mt Shasta	Damaged Equipment	Y	1,957,567	1,604
	4/7/2017	Crescent City	Wind Blown Tree	Y	1,119,257	1,474
	4/7/2017	Crescent City	Wind Blown Tree	Y	987,987	3,396
	1/9/2017	Yreka/Mt Shasta	Heavy Snow Storm	Y	985,255	1,776
	4/7/2017	Crescent City	Wind Blown Tree	Y	947,025	5,175
	1/19/2017	Yreka/Mt Shasta	Loss of Transmission Line	Y	886,326	763
	1/3/2017	Yreka/Mt Shasta	Loss of Transmission Line	Y	869,891	1,524
	1/19/2017	Yreka/Mt Shasta	Damaged Equipment	Y	714,873	561
	1/18/2017	Yreka/Mt Shasta	Heavy Snow Storm	Y	689,554	2,298
	1/18/2017	Yreka/Mt Shasta	Loss of Transmission Line	Y	674,919	352

Historical Top Ten Unplanned Outage Events by Year						
Year	**Date**	**District**	**Description**	**Excluded Major Event?**	**Total Customer Minutes Lost**	**Total Customers in Incident**
2016	10/17/2016	Crescent City	Loss of Transmission Line	Y	926,778	10,972
	6/5/2016	Yreka/Mt Shasta	Loss of Transmission Line	Y	853,260	4,736
	6/17/2016	Yreka/Mt Shasta	Loss of Transmission Line	N	478,225	6,248
	12/21/2016	Crescent City	Wind Blown Tree	Y	388,500	420
	8/28/2016	Yreka/Mt Shasta	Forest Fire	N	363,287	1,404
	12/21/2016	Crescent City	Wind Blown Tree	Y	311,097	336
	2/5/2016	Yreka/Mt Shasta	Loss of Transmission Line	N	302,123	8,349
	4/13/2016	Yreka/Mt Shasta	Wind Storm	N	291,507	6,016
	1/13/2016	Crescent City	Pole Fire	N	278,218	8,577
	2/5/2016	Yreka/Mt Shasta	Loss of Transmission Line	N	274,030	3,724
2015	2/5/2015	Crescent City	Loss of Transmission Line	Y	1,852,631	3,150
	2/7/2015	Crescent City	Wind Blown Tree	Y	1,036,585	1,222
	2/6/2015	Crescent City	Wind Blown Tree	Y	922,607	1,047
	2/7/2015	Crescent City	Wind Blown Tree	Y	922,282	1,884
	2/7/2015	Crescent City	Wind Blown Tree	Y	713,868	380
	2/5/2015	Crescent City	Loss of Transmission Line	Y	649,753	2,100
	2/7/2015	Crescent City	Loss of Transmission Line	Y	636,947	1,719
	7/7/2015	Yreka/Mt. Shasta	Loss of Transmission Line	Y	538,624	3,156
	4/25/2015	Yreka/Mt. Shasta	Tree	N	528,711	9,320
	2/7/2015	Crescent City	Emergency Damage Repair	Y	455,081	3,024
2014	10/25/2014	Crescent City	Loss of Transmission Line	Y	2,424,849	7,448
	10/25/2014	Crescent City	Loss of Transmission Line	Y	1,084,725	1,533
	9/15/2014	Yreka/Mt. Shasta	Loss of Transmission Line	Y	890,396	13,280
	9/15/2014	Yreka/Mt. Shasta	Loss of Transmission Line	Y	802,134	5,660
	10/25/2014	Crescent City	Loss of Transmission Line	Y	517,764	453
	9/15/2014	Yreka/Mt. Shasta	Intentional to Clear Trouble	Y	498,809	1,205
	3/24/2014	Crescent City	Loss of Transmission Line	N	484,466	798
	10/25/2014	Crescent City	Loss of Transmission Line	Y	478,808	1,176
	5/5/2014	Yreka/Mt. Shasta	Pole fire	N	472,976	1,875
	8/17/2014	Yreka/Mt. Shasta	Loss of Transmission Line	N	471,399	3,070
2013	8/25/2013	Yreka/Mt. Shasta	Loss of Transmission Line	Y	2,210,746	14,259
	8/25/2013	Yreka/Mt. Shasta	Loss of Transmission Line	Y	2,087,998	10,500
	9/5/2013	Yreka/Mt. Shasta	Loss of Substation	N	731,594	1,451
	10/27/2013	Yreka/Mt. Shasta	Loss of Transmission Line	N	466,576	1,452
	5/11/2013	Yreka/Mt. Shasta	Loss of Transmission Line	N	398,507	2,093
	8/22/2013	Tulelake/Alturas	Loss of Transmission Line	N	361,772	2,407
	7/9/2013	Tulelake/Alturas	Emergency Damage Repair	N	301,141	970
	9/30/2013	Crescent City	Tree	N	299,295	458
	5/20/2013	Yreka/Mt. Shasta	Loss of Substation	N	297,838	1,042
	12/9/2013	Yreka/Mt. Shasta	Loss of Substation	N	297,317	1,663

Historical Top Ten Unplanned Outage Events by Year						
Year	**Date**	**District**	**Description**	**Excluded Major Event?**	**Total Customer Minutes Lost**	**Total Customers in Incident**
2012	12/20/2012	Yreka/Mt. Shasta	Weather	Y	1,789,753	3,108
	12/20/2012	Yreka/Mt. Shasta	Emergency Damage Repair	Y	1,691,153	11,788
	11/29/2012	Yreka/Mt. Shasta	Tree	N	876,375	12,070
	9/30/2012	Yreka/Mt. Shasta	Loss of Transmission Line	Y	807,000	3,078
	12/23/2012	Yreka/Mt. Shasta	Loss of Transmission Line	Y	697,305	373
	12/22/2012	Yreka/Mt. Shasta	Intentional to Clear Trouble	Y	681,990	508
	9/30/2012	Yreka/Mt. Shasta	Loss of Transmission Line	Y	568,353	6,469
	12/21/2012	Yreka/Mt. Shasta	Weather	Y	560,115	414
	12/24/2012	Yreka/Mt. Shasta	Tree	Y	509,765	438
	12/13/2012	Yreka/Mt. Shasta	Loss of Transmission Line	N	389,226	1,653
2011	10/10/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	870,734	3,612
	7/31/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	664,757	7,652
	3/24/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	550,141	1,042
	9/15/2011	Yreka/Mt. Shasta	Emergency Damage Repair	N	516,786	3,608
	7/31/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	501,237	6,308
	7/31/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	449,576	5,189
	12/10/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	430,949	546
	2/17/2011	Yreka/Mt. Shasta	Loss of Transmission Line	N	383,111	1,043
	3/18/2011	Yreka/Mt. Shasta	Weather	N	354,489	9,340
	12/23/2011	Crescent City	Loss of Transmission Line	N	332,817	839

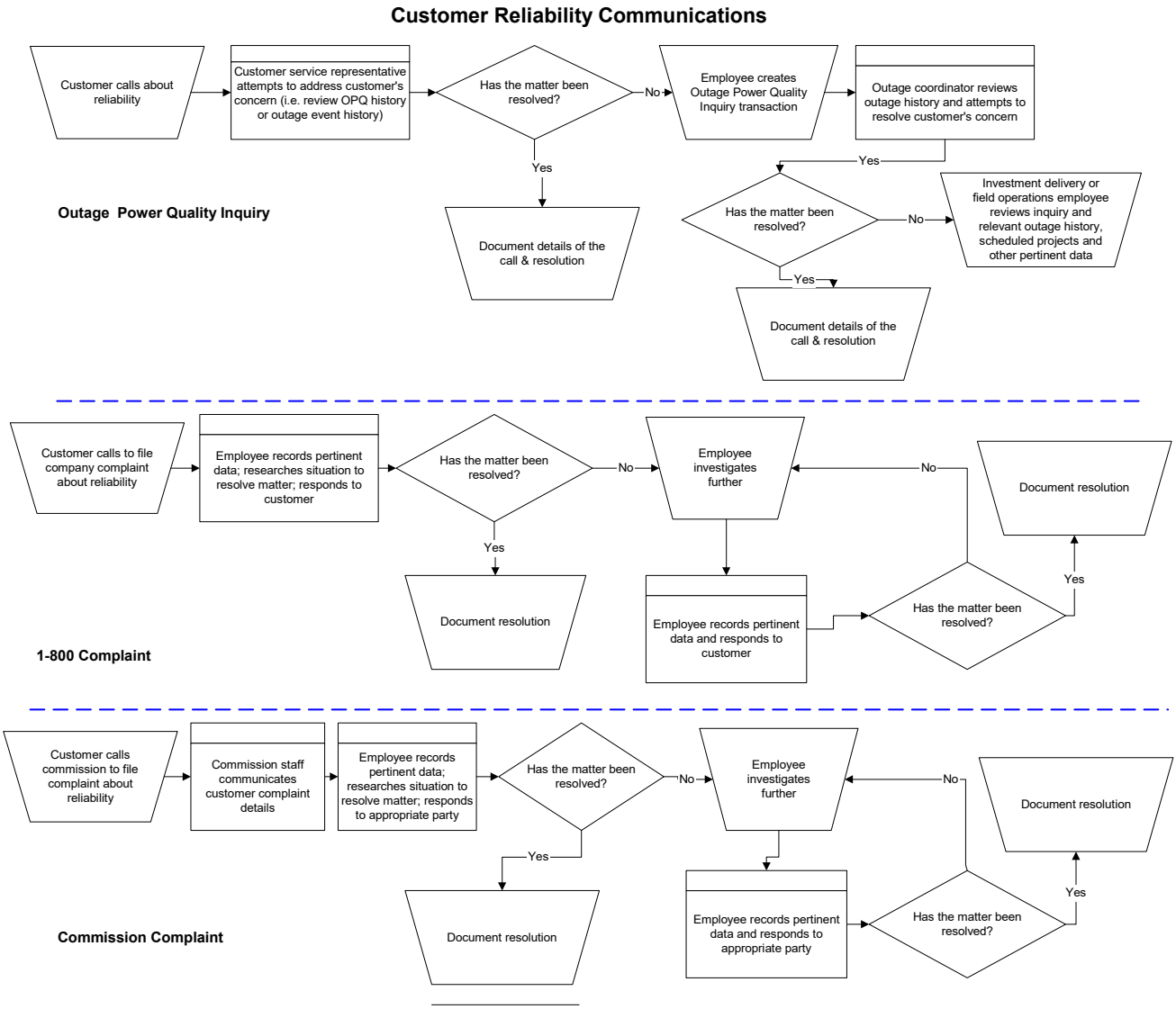
Customer Inquiries and Response

Customer Reliability Communications

PacifiCorp has internet addresses to provide customer guidance on how to request reliability information as well as to view reliability overview metrics and the year's reliability report. The metric information is located at https://www.pacificpower.net/ca-report while the link to request reliability information for a specific customer is located at https://www.pacificpower.net/reliability. Further, in compliance with the rules, PacifiCorp will be scheduling its annual meeting in the fall to review these results in the ordered public meeting.

Reliability Inquiry and Complaint Process Overview

The Company's process for managing customers' concerns about reliability are to provide opportunities to hear customer concerns, respond to those concerns, and where necessary, provide customers an opportunity to elevate those concerns.



Customer Reliability Inquiry/Complaint Tracking

Listed below are the various avenues available to a customer to resolve concerns about reliability performance.

- **Customer Reliability Inquiry**

  The company records customer inquiries about reliability as Outage Power Quality transactions in its customer service system, referred to as "OPQ" transactions.

- **Customer Complaint**

  If a customer's reliability concerns are not met through the process associated with the OPQ transaction, a customer can register a 1-800 complaint with the company. This is recorded in a complaint repository from which regular reports are prepared and circulated for resolution.

- **Commission Complaint**

  If a customer's reliability concerns are not met through the process associated with a 1-800 complaint, a customer can register a complaint with the Commission. This is recorded by the Commission staff and also by the company in a complaint repository. Regular reports are prepared and circulated for resolution of these items.

2021 Customer Reliability Inquiry Responses

The table below illustrates PacifiCorp's response periods for each customer reliability inquiry received in 2021. The response time for each inquiry reports calendar days from the date of the initial inquiry to the date on which the company contacts the customer to discuss the specific circumstances associated with the inquiry. Certain outlier records report the duration until investigation was completed because of incomplete customer contact records.

Response Time (Days)	Customer Inquiries (non-outage Related)	Customer Outage Inquiries	Response Time (Days)	Customer Inquiries (non-outage Related)	Customer Outage Inquiries
1	11	9	**17**	0	0
2	7	5	**18**	0	0
3	0	1	**19**	0	0
4	2	2	**20**	0	0
5	0	1	**21**	0	0
6	3	0	**22**	0	0
7	0	0	**23**	1	0
8	0	0	**24**	1	0
9	0	0	**25**	0	0
10	0	1	**26**	0	0
11	1	0	**27**	1	0
12	2	1	**28**	0	0
13	1	0	**29**	1	0
14	2	0	**30**	0	0
15	0	0	**31+**	3	0
16	0	1			

Appendix A: Historical Top Ten Unplanned Power Outage Events Due to Wildfire

On April 17, 2018, California Public Utilities Commission's Energy Division requested that companies also report information regarding wildfire-related power outages in their annual electric reliability reports. While PacifiCorp was not a direct recipient of this request, it was forwarded by other utility contacts as below.

From: "Lee, David K." <david.lee@cpuc.ca.gov>
Date: April 17, 2018 at 12:56:18 PM GMT-6
To: "'Wright, Jennifer'" <JWright@semprautilities.com>, "'Plummer, Matthew'" <M3Pu@pge.com>, "'Wendy.Phan@sce.com'" <Wendy.Phan@sce.com>, "'Moore, Ronald K.'" <RKMOORE@gswater.com>, "'Quan, Nguyen'" <Nguyen.Quan@gswater.com>, "FTP Admin" <ftpadmin@cpuc.ca.gov>, "Ken Wittman (ken.wittman@libertyutilities.com)" <ken.wittman@libertyutilities.com>, "'Prabhakaran, Vidhya'" <VidhyaPrabhakaran@dwt.com>
Cc: "Regnier, Justin" <Justin.Regnier@cpuc.ca.gov>, "Petlin, Gabriel" <gabriel.petlin@cpuc.ca.gov>
Subject: Please include detailed information of Wildfire Related Power Outages in the Electric Annual Reliability Reports

Dear All,

Appendix B of Decision (D.) 16-01-008 (Reliability Reporting Template) requires utilities to report the top 10 unplanned power outage events each year. However, for each of the top 10 unplanned power outage events and Major Event Days (MED) that are due to wildfire, please also include all the following information in your Electric Annual Reliability Reports:

- A description of the event (cause, location, etc.)
- Dates of the event
- The number of customer affected by the event
- Longest customer interruption in hours
- # of utility staff and other utility staff (mutual assistance) to restore service
- Coordination with other electric, gas, and telecommunication companies
- The number of customers who have repeated power interruptions during the event (due to weather, equipment failure, etc.)
- The number of customers whose power was interrupted in order to restore power service.
- The number of customer without power during the event in hourly interval
- The factors that affect the restoration of power (lesson-learned, communication, safety, access, weather, etc.)
- Estimated cost for the utility to restore electric services for the event

Please include these additional reporting requirements in the 2017 Electric Annual Reliability Report (Due on 7/15/2018).

PacifiCorp has determined that three of its historic top ten outages qualified and are reported upon below.

9/8/2020 Slater Wildfire Event Detail in Yreka/Mt Shasta

Outage Detail

The Slater Fire began on September 8th, 2020, at approximately 6:38 a.m. when the Slater Butte lookout reported smoke. The fire developed quickly as high winds and low humidity fueled the growth. In addition, downed trees impacted and impeded access to the area, while the high winds grounded and slowed any air attacks to address the rugged terrain, difficult to access by vehicles.

Company personnel coordinated response and area recovery efforts to restore power to key locations such as the local water treatment plant, CalFire station, and other facilities deemed critical at the request of the Incident Commander or Siskiyou County Emergency Operations Center. Vegetation crews were also dispatched to the area to mitigate hazards, continuing to work throughout the area dealing with hazards left behind by the fire. In order to restore as rapidly as possible, the company mobilized portable generators which were used to temporarily re-energize areas while distribution and transmission was being reconstructed. As areas were deemed safe for entry Pacific Power crews were able to begin repairing damaged equipment and restoring power. In total the fire damaged approximately 59 transmission poles, 58 distribution poles, and 32 joint Transmission and distribution poles, all of which were replaced.

The Slater fire was just one of many fires which occurred during this time frame in the Northwest. In addition to local personnel the company brought in additional support from across its territory in Oregon and Washington to assist with damage assessments, restoration activities for key community support facilities, in addition to assisting community members across our service territory with essential resource support.

The major event period for this event began on September 8, 2020 and continued through September 17, 2020. The burn area encompassed three circuits, two from Happy Camp, California, and one fed from a Grants Pass, Oregon substation, which extends into areas of northern California[9]. During this period there were a total of 11 outages which occurred, four were the result of generator startup and two were planned outages. Approximately 1,000 customers were affected by the Slater fire.

On November 16, 2020, the Klamath Nation Forest managers declared the Slater Fire contained at 157,270 acres burned in California and Oregon.

Restoration Intervals

# Customers without power by hourly intervals							
Hours	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**
0-27	772	123-147	283	192-195	458	225-249	201
27-48	822	147-150	295	195-204	422	249-294	151
49-54	448	150-153	281	204-213	386	249-297	5
54-108	419	153-162	269	213-219	262	297+	0
108-126	349	162-183	817	219-222	264		
126-132	302	183-192	334	222-225	262		

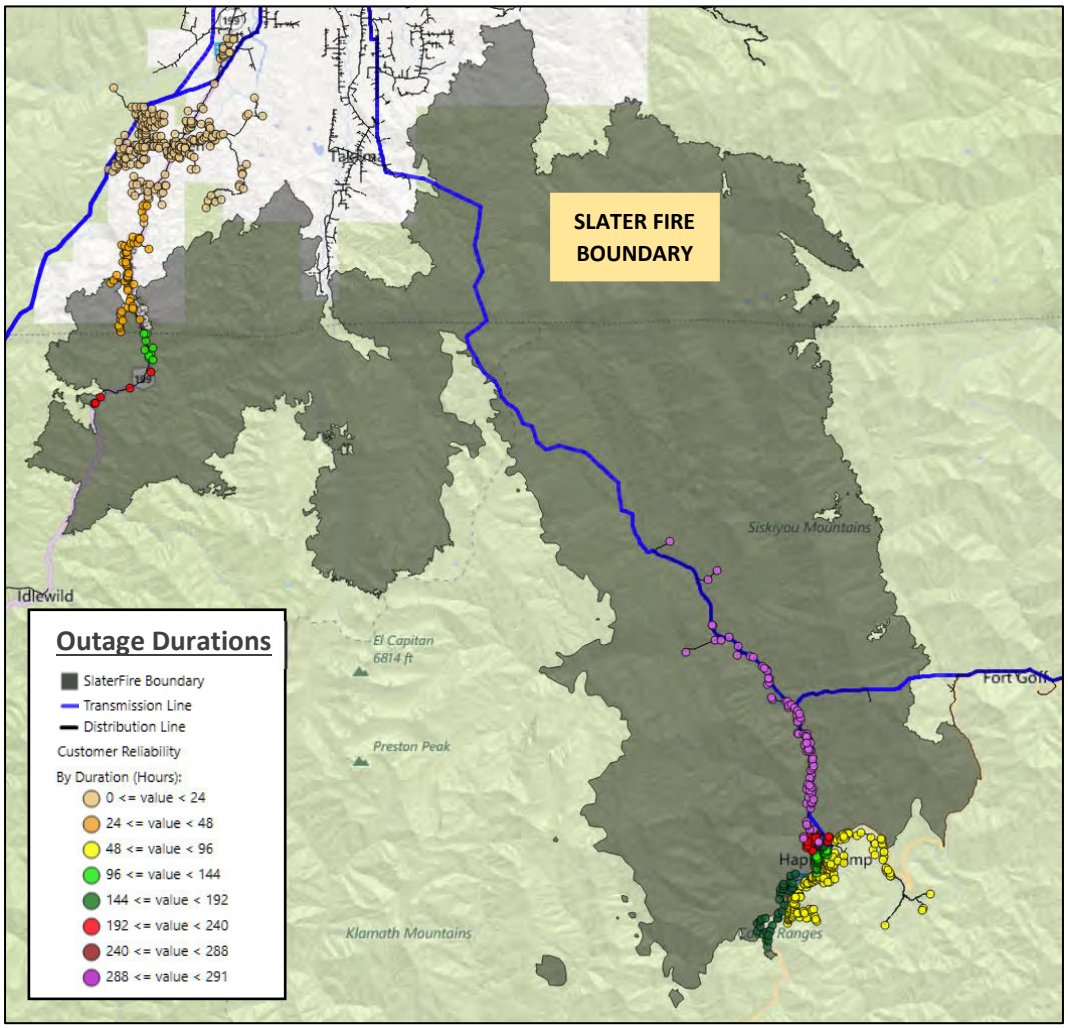
[9] The numbers and analysis do not separate out the customers fed from Circuit 5R106 whose substation is located in Grants Pass, Oregon. Approximately 34 customers fed from this circuit are in California. Therefor the numbers in the graphs and charts include approximately 110 customers which reside in Oregon.

Event Outage Summary	
Date	**9/8/2020 – 9/17/2020**
District	**Yreka/Mt. Shasta**
Cause	**Wildfire**
# Interruptions (sustained)	**11**
Total Customer Interruptions (sustained)	**1,612**
Longest Customer Interruption	**12 days 4 hours 39 minutes**
Total Approx. Personnel Utilized during event	**503**
Internal crewmembers	*65*
Approx. Contractor Crewmembers	*78*
Approx. Vegetation crewmembers[10]	*360*
Other Utility Coordination	**None**
# Customers experiencing multiple outages[11]	**582**
# Customers indirectly affected	**0**
Estimated Cost	***$ 53,703,983***
Expense	*$ 1,439,511*
Capital	*$ 52,264,472*

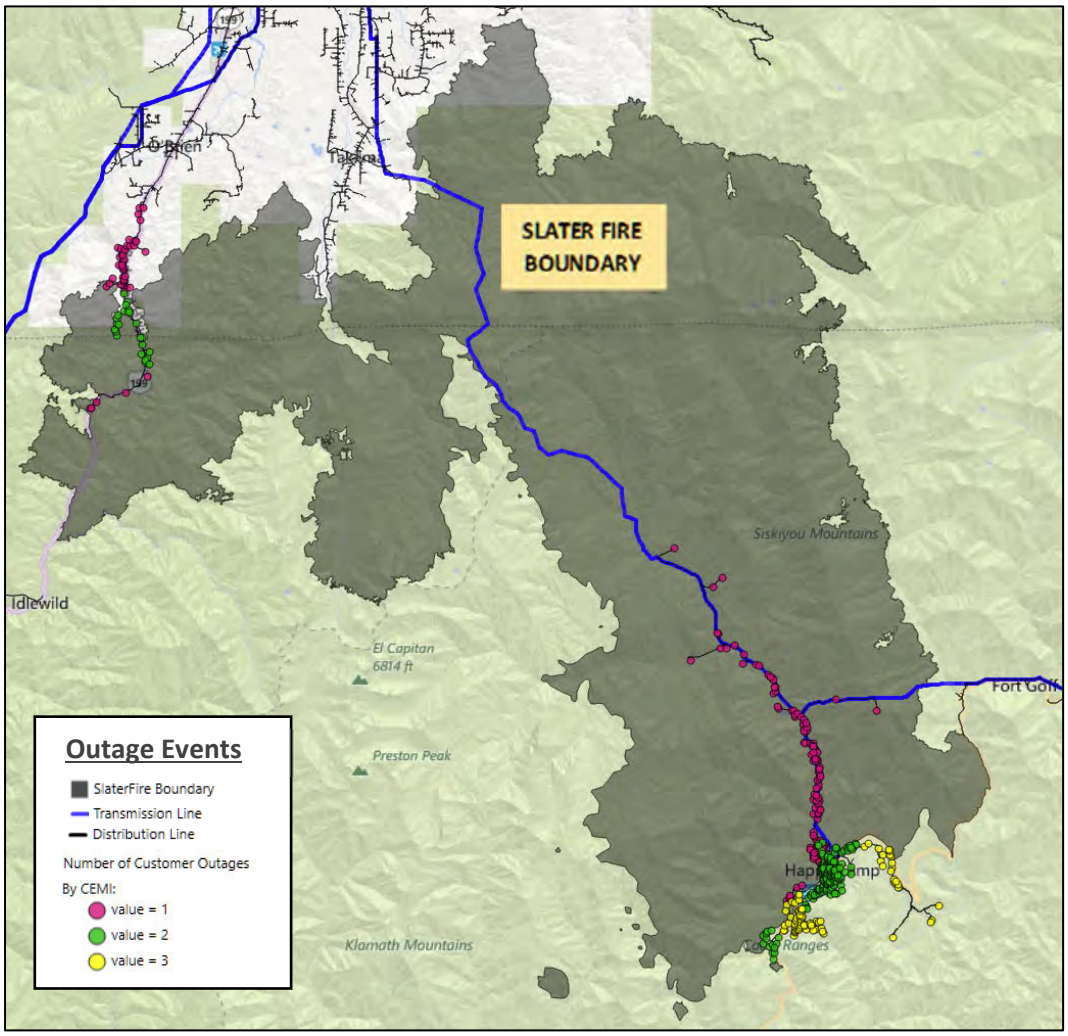
Slater Fire Incident Information:	
Date/Time Started:	September 8, 2020
Contained Declaration Date:	November 16, 2020
Administrative Unit:	Klamath National Forest
County:	Siskiyou County, Del Norte, and Josephine County (Oregon)
Estimated - Containment:	157,270 acres - contained

[10] Vegetation contract personnel is accrued per day not per crewmember, therefor amounts provided include a total of each specific contractor companies' day when the largest number of personnel were used.
[11] Outage data run for the period of the major event timeframe from September 8th through 17th, 2020.

Slater Fire overlaid on PacifiCorp's circuit topology and Total Customer Duration



Slater Fire overlaid on PacifiCorp's circuit topology and Total Customer Events



9/5/2018 Delta Wildfire Event Detail in Mt. Shasta

Outage Detail

The Delta Fire started in multiple locations on September 5th, 2018, at approximately 12:30 pm and was ultimately deemed human caused, but was not ruled an arson. The fire quickly grew affecting 63,311 acres, causing several road closures including several miles of Interstate-5. Company personnel coordinated response and area recovery efforts to restore power to key locations such as the local water treatment plant, CalFire station, and other facilities deemed critical at the request of the Incident Commander or Siskiyou County Emergency Operations Center. Vegetation crews were also dispatched to the area to mitigate hazards, continuing to work throughout the area dealing with hazards left behind by the fire. As areas were deemed safe for entry Pacific Power crews were able to begin repairing damaged equipment and restoring power. In total the fire damaged approximately 190 transmission poles, and 48 distribution poles, all of which were replaced.

Event Outage Summary	
Date	**9/5/2018**
District	**Yreka/Mt. Shasta**
Cause	**Wildfire**
# Interruptions (sustained)	**3**
Total Customer Interrupted (sustained)	**166**
Longest Customer Interruption	**27 days 4 hours 55 minutes**
Total Personnel Utilized during event	**235**
Internal crewmembers	*84*
Vegetation crewmembers	*151*
Other Utility Coordination	**None**
# Customers experiencing multiple outages	**0**
# Customers indirectly affected	**0**
Estimated Cost	***$ 29,117,924.20***
Expense	*$ 1,446,757.98*
Capital	*$ 27,671,166.22*

Restoration Intervals

# Customers without power by hourly intervals									
Hours	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**
< 1-73	166	**171-191**	111	**260-263**	76	**308-318**	11	**652**	0
74-170	149	**192-260**	77	**264-308**	15	**319-651**	9		

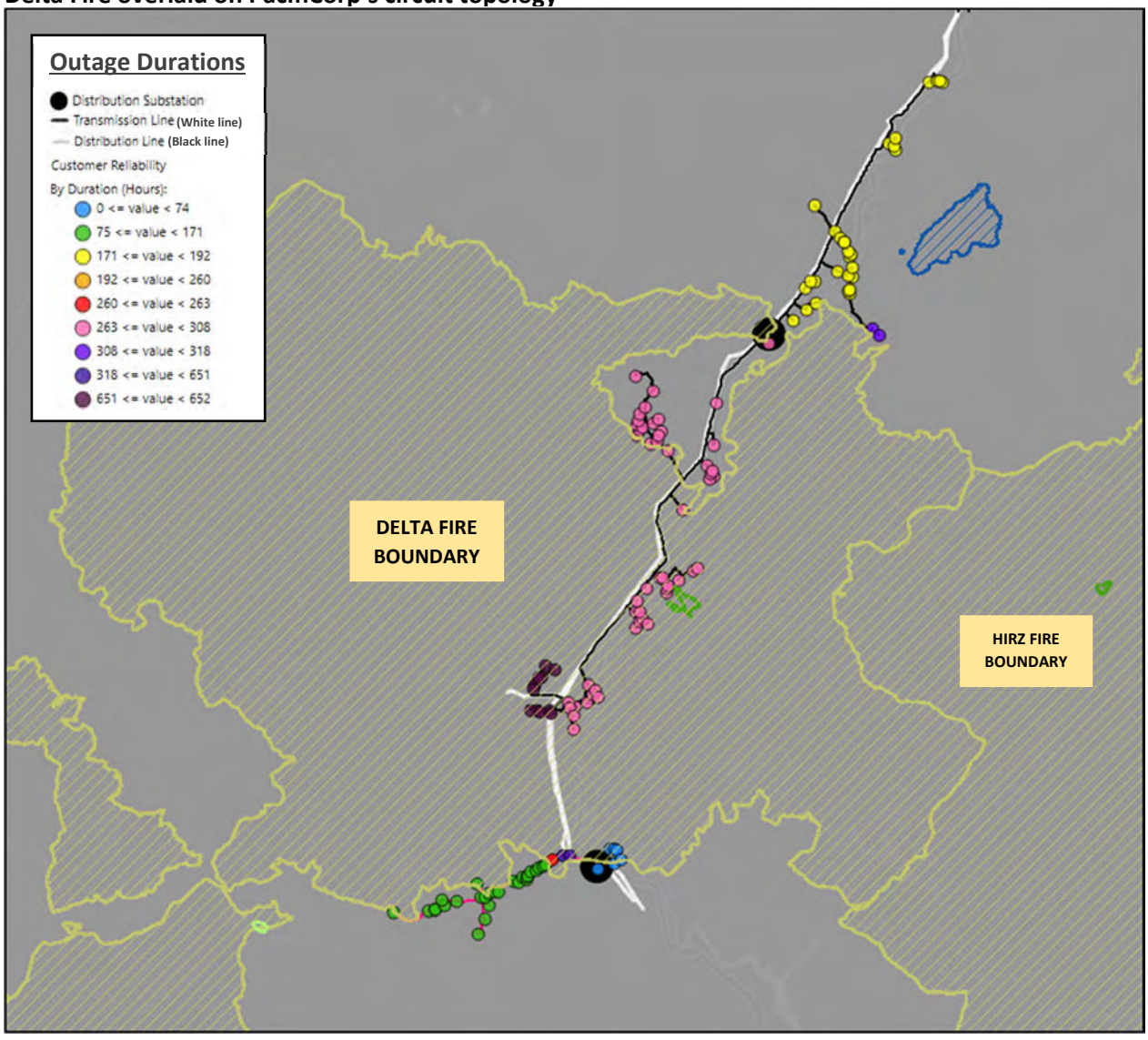
CalFire's report on the fire incident resulting in de-energization is displayed below[12]:

Delta Fire Incident Information:		
Last Updated:	January 4, 2019 9:07 am	FINAL
Date/Time Started:	September 5, 2018 12:51 pm	
Administrative Unit:	USFS Shasta-Trinity National Forest	
County:	Shasta County	
Location:	I-5 and Lamoine, 2 miles NW of Lakehead	
Estimated - Containment:	63,111 acres - 100% contained	

Delta Fire equipment damage photographic impact

[12] http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=2242

Delta Fire overlaid on PacifiCorp's circuit topology



8/26/2016 Gap Wildfire Event Detail in Yreka

Outage Detail

On August 28, 2016, the United States Forest Service notified company officials in Yreka of a forest fire burning near company equipment and requested that the circuit be de-energized as fire crews worked to extinguish the fire. The fire incident was called the Gap Fire and the fire incident report information is contained below. The outage event affected a total of 351 customers with 63 customers' power restored in 59 minutes, 12 customers' power restored in 16 hours 14 minutes, 234 customers' power restored in 17 hours 14 minutes, and 42 customers' power restored in 42 hours 4 minutes.

Event Outage Summary	
Date	8/28/2016
District	Yreka/Mt. Shasta
Cause	Wildfire
# Interruptions (sustained)	1
Total Customer Interrupted (sustained)	351
Longest Customer Interruption	42 hours 4 minutes
Total Personnel Utilized during event	30
Internal crewmembers	*9*
Vegetation crewmembers	*21*
Other Utility Coordination	None
# Customers experiencing multiple outages	0
# Customers indirectly affected	0
Estimated Cost	$90,319

Restoration Intervals

# Customers without power by hourly intervals									
Hours	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**	**Hours**	**Customers Out**
< 1	351	**10**	288	**20**	42	**30**	42	**40**	42
> 1	288	**11**	288	**21**	42	**31**	42	**41**	42
2	288	**12**	288	**22**	42	**32**	42	**42**	42
3	288	**13**	288	**23**	42	**33**	42	**43**	0
4	288	**14**	288	**24**	42	**34**	42	**44**	0
5	288	**15**	288	**25**	42	**35**	42	**45**	0
6	288	**16**	288	**26**	42	**36**	42	**46**	0
7	288	**17**	276	**27**	42	**37**	42	**47**	0
8	288	**18**	42	**28**	42	**38**	42	**48**	0
9	288	**19**	42	**29**	42	**39**	42	**49**	0

Other correspondence

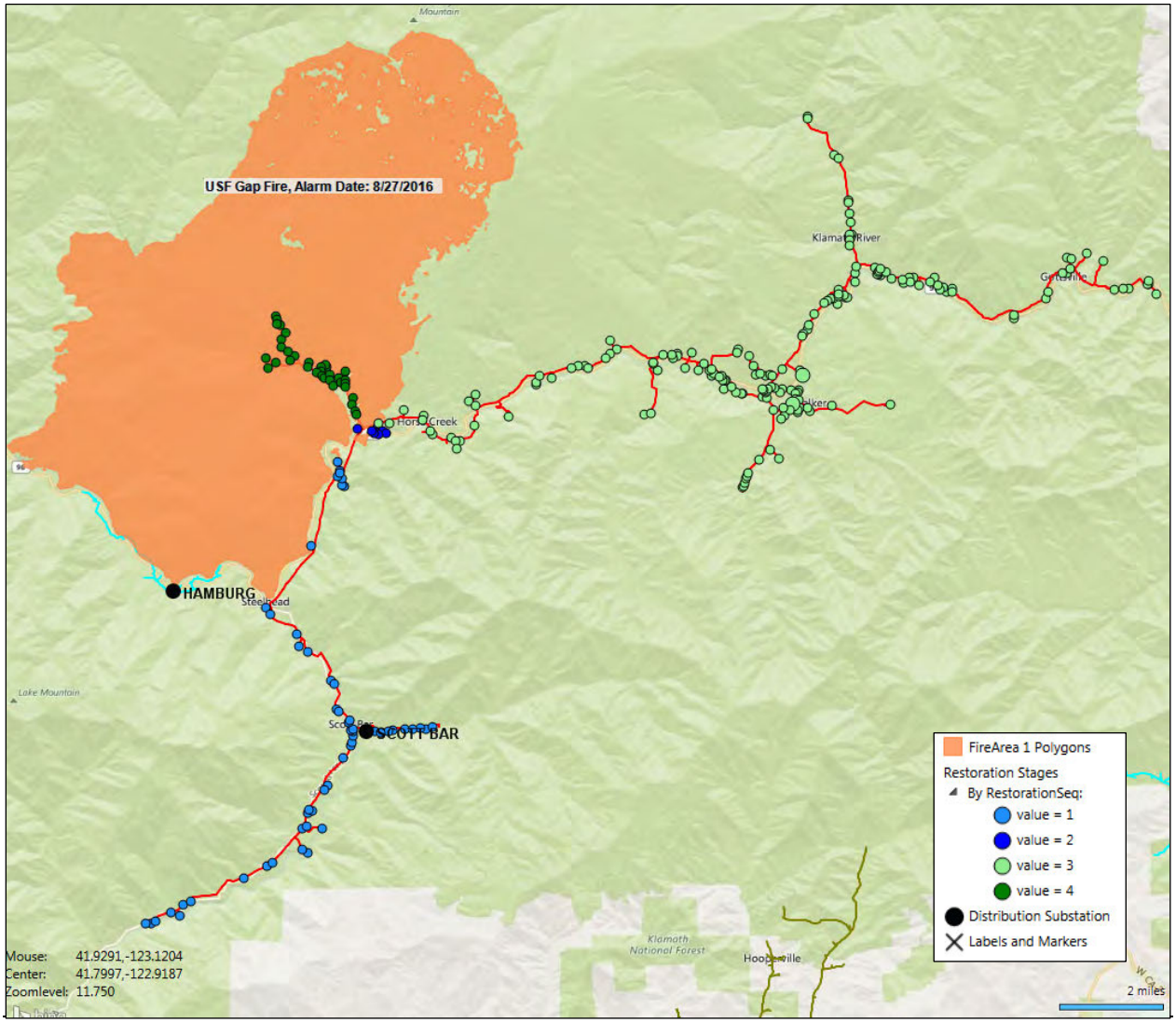
On August 29, 2016 PacifiCorp filed incident report 1915, communicating about the impact of the Gap fire to its customers, and subsequently was told that since the incident did not meet reporting thresholds it should not have communicated such information to the incident reporting system. The information communicated is conveyed below.

-----Original Message-----
From: kathleen.sauer@pacificorp.com [mailto:kathleen.sauer@pacificorp.com]
Sent: Monday, August 29, 2016 5:33 PM
To: Lee, David K.; Blumer, Werner M.; rae@cpuc.ca.gov; Clanon, Paul
Subject: NEW Incident Reported - Incident No: 1915
A new Electric incident has been reported as follows: Reporting Date: 8/29/2016 5:30:13 PM. Incident Date: 8/27/2016. Incident Time: 6:00 p.m.. Reported By: Kathleen Sauer. Utility Name: Pacific Power. Phone Number: 503-703-8571. Email Address: kathleen.sauer@pacificorp.com. Est. Ending Date: . Est.Ending Time: 00:00 a.m.. Location: Five miles east of Seiad, CA and two miles north of O'Neil Campground. Description: Gap Fire - five miles east of Seiad, CA and two miles north of O'Neil Campground. Comments: Saturday, August 27, 2016 @ 18:00 PM
Pacific Power was advised of the Gap Fire that started at 18:00 PM about five miles east of Seiad, California and two miles north of O'Neil Campground, on Highway 95.
Fire resources responded to the scene Saturday evening and began initial attack activities. Fire behavior increased late Sunday afternoon and through the night due to heavy fuels, many years of drought and strong erratic winds.
Mandatory evacuations were issued for the communities of Hamburg and Horse Creek. An advisory evacuation notice was issued for the community of Scott Bar. Highway 96 was closed from the junction of Highway 263 to the junction of Scott River Road.
Local residents have access on the section of Highway 96 to Cherry Flat. The section of Highway 96 from Cherry Flat to the junction of Scott River Road is "hard" closure and only fire fighter vehicles are allowed.
Sunday, August 28, 2016 @ 22:17 PM
At the request of the local fire authorities Pacific Power de-energized 320 customers out of the Scotts Bar area on circuit 5G40. At this time there are first responders in the area to assist fire crews. There are no estimated restoration times for the outages and no damage assessments available.
Monday, August 29, 2016 @ 8:43 AM
Pacific Power issued the following media alert:
In order to help firefighters safely battle the Seid Fire, Pacific Power has de-energized about 320 customers in the area of Scotts Bar. This will allow the fire crews a freer hand in doing their work. Pacific Power is on stand-by in the area should any further actions become necessary.
Monday, August 29, 2016 @ 9:22 AM
Pacific Power was advised that the fire has grown to approximately 3,500 acres and is 0% contained. Highway 96 is closed at the junction of Highway 263. Evacuations are in place for Horse Creek, Scott Bar and Hamburg.
Because of fire restrictions, no damage assessments have been made. There are 42 customers who remain without power. There is no estimated time to gain access for damage assessment until fire resources gives us permission. We have one serviceman staged at their incident command for response.
Monday, August 29, 2016 @ 16:59 PM
By Monday morning the size of the fire had increased to 5,000 acres.
Pacific Power received approval to assess some of the area but the majority of the damaged area is restricted. At this time our information shows the fire moving away from our transmission and distribution structures.
At 13:30 PM Pacific Power was given permission to energize some of our lines following inspection and to restore service to those areas safe from the fire. There are 42 customers who remain without power.
There is very little containment and the winds are predicted to pick up this afternoon. A first responder is stationed in the area overnight and will work directly with fire authorities. There are no estimated time of restoration or prediction of entry into the fire damaged areas for assessment at this time.
The cause of the Gap fire is under investigation.

CalFire's report on the fire incident resulting in de-energization is displayed below[13]:

Gap Fire Incident Information:	
Last Updated:	August 28, 2016 6:15 pm FINAL
Date/Time Started:	August 27, 2016 6:00 pm
Administrative Unit:	USFS Klamath National Forest
County:	Siskiyou County
Location:	off Seiad Creek Rd, 5 miles northeast of Seiad Valley
Estimated - Containment:	33,867 acres - 100% contained **This is NOT a CAL FIRE incident. For more information from the US Forest Service, click on the link above.

Gap Fire overlaid on PacifiCorp's circuit topology



[13] http://cdfdata.fire.ca.gov/incidents/incidents_details_info?incident_id=1400

DECLARATION OF

AMY McCLUSKEY (PACIFICORP)

1. My name is Amy McCluskey. My business address is 825 NE Multnomah Street, Suite 1700, Portland, Oregon 97232.

2. I am the Managing Director, Wildfire Safety and Asset Management for PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company). Mr. Allen Berreth, Vice President of Transmission & Distribution Operations, has delegated authority to me, Amy McCluskey, to sign this declaration. PacifiCorp is a multi-jurisdictional utility providing electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 47,000 customers in portions of Del Norte, Modoc, Shasta, and Siskiyou Counties in northern California.

3. This declaration is based on my information and belief and is submitted for the purpose of requesting confidential treatment of portions of PacifiCorp's annual reliability report submitted to the Commission on July 15, 2022,[1] in accordance with General Order (GO) 66-D of the California Public Utilities Commission (Commission). PacifiCorp submitted both confidential and public versions of the report. Planned outage data is redacted from the public version.

4. Section 3.2 of GO 66-D provides that when a utility submits to the Commission or Commission staff documents for which the utility seeks confidential treatment outside of a formal proceeding, the utility must mark the document or applicable portions thereof confidential and provide a specific citation to the California Public Records Act that authorizes confidential

[1] PacifiCorp is concurrently submitting a copy of this report to the Energy Division Central Files, Lee Palmer, Julian Enis, and Forest Kaser with the same claim of confidentiality.

treatment. Additionally, any such request must be accompanied by a declaration signed by an officer of the requesting entity.

5. PacifiCorp requests confidential treatment of the planned outage data in the confidential version under Decision (D.) 16-01-008, as explained below, and Government Code Sections 6254(e) and (k). The pages of the confidential version of the report with planned outage data for which confidential treatment is requested have been marked in compliance with Section 3.2(a) of GO 66-D.

6. Under D. 16-01-008, the Commission updated the electric reliability reporting requirements for California electric utilities. D.16-01-008 requires utilities to submit annual information about planned outages to the Energy Division and the Safety and Enforcement Division on a confidential basis.[2] As noted in D.16-01-008, "making planned outage data public poses a potential risk as the data could expose grid vulnerabilities. Therefore, planned outage data should be confidential to protect the public from potential harmful activities that could damage the grid and electric reliability." See D.16-01-008 at p.19.

I declare under penalty of perjury of the laws of the state of California that the foregoing is true and correct.

Executed in Portland, Oregon, July 15, 2022.

Amy McCluskey
Managing Director, Wildfire Safety and Asset Management
PacifiCorp

[2] D.16-01-008, at p.18.

ATTACHMENT 6

Liberty's Electric System Reliability Annual Report 2019

ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2019

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

February 1ST, 2020

CA-08-0132

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2019 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents nine years (2011 through 2019) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2019 was 171.00 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

Table of Contents

1) System Indices for the Last 9 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

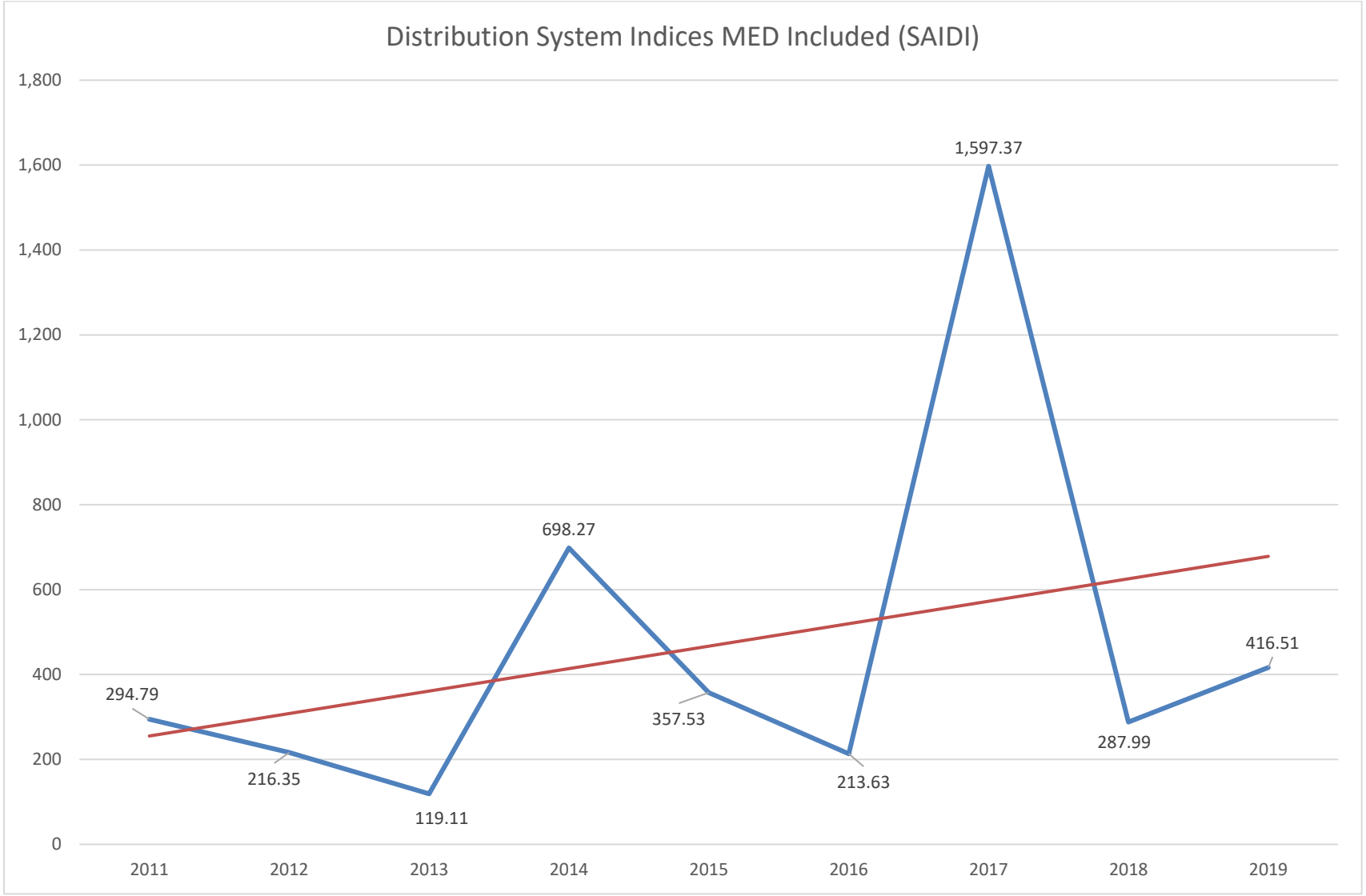
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 9 Years (Years in Business)

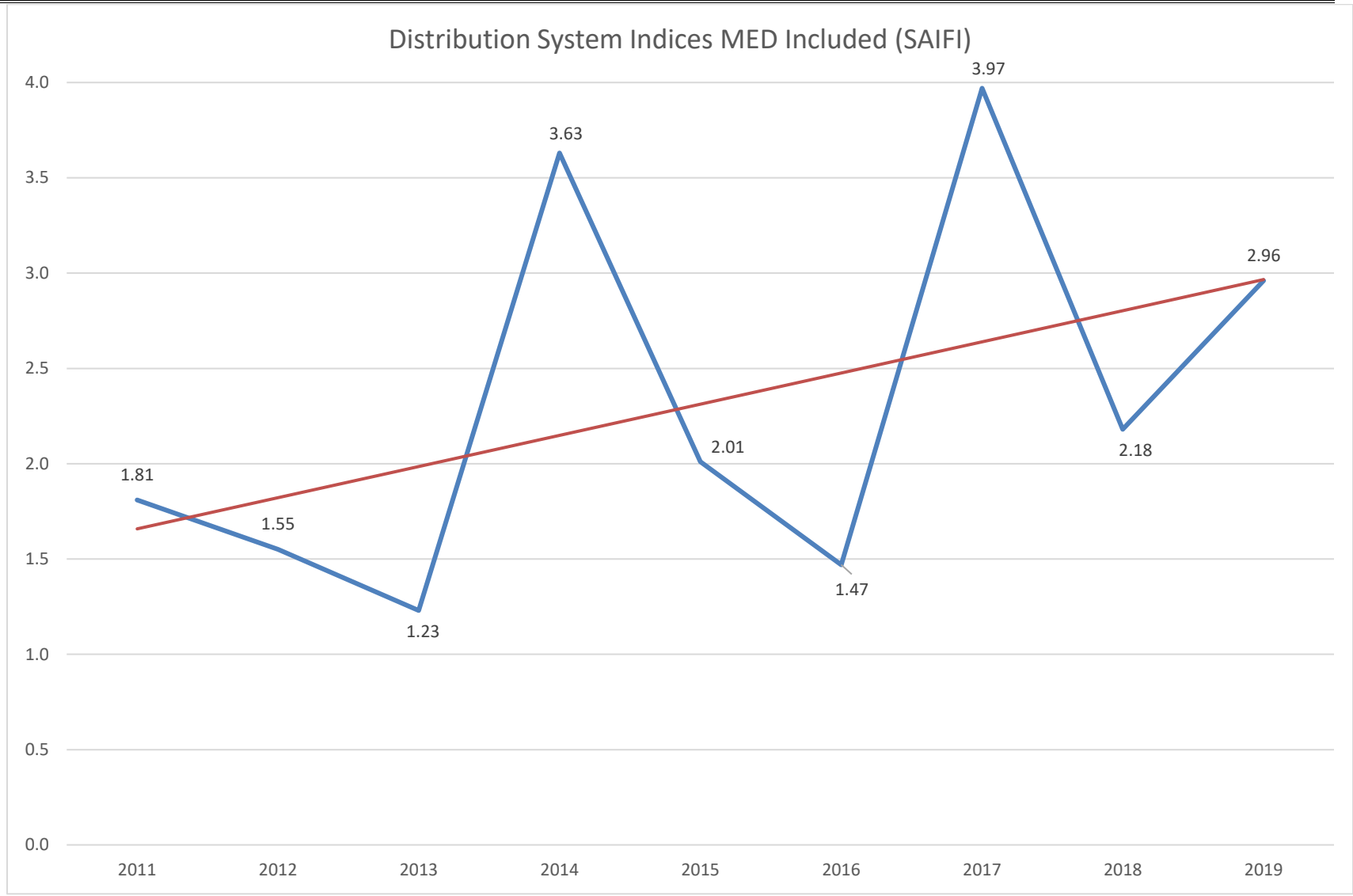
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

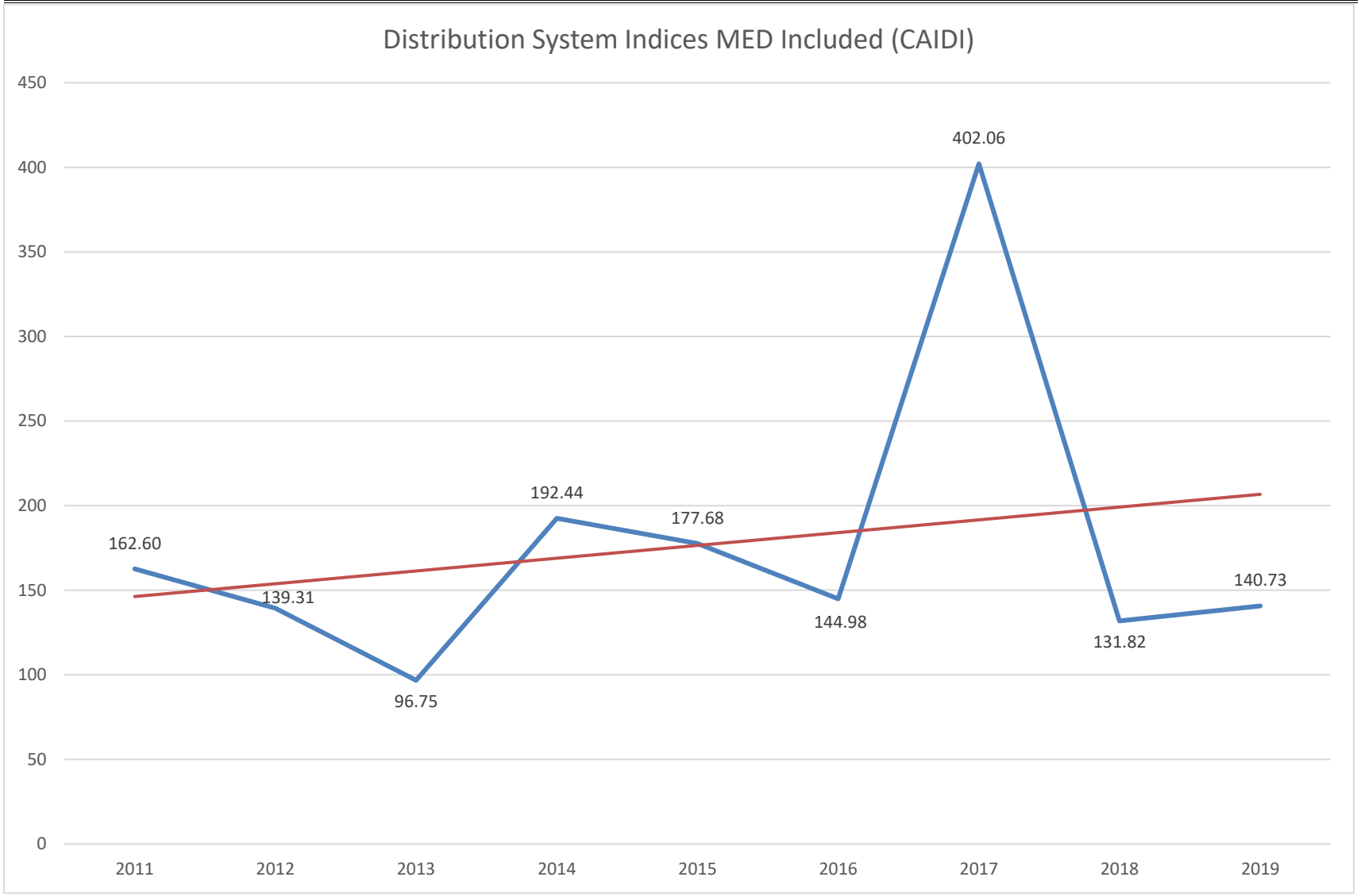
II. Transmission System Indices (MED Included and Excluded)

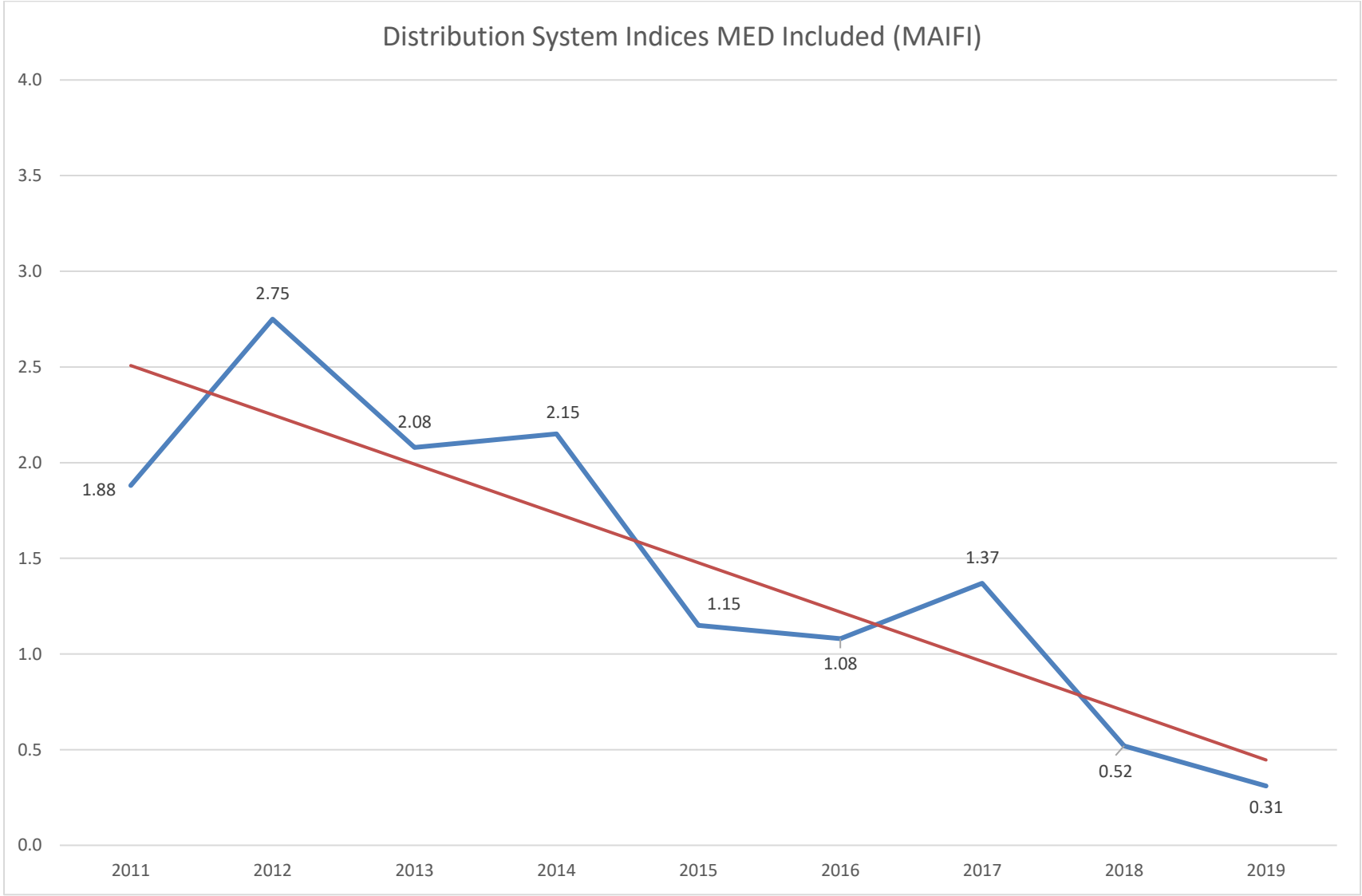
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

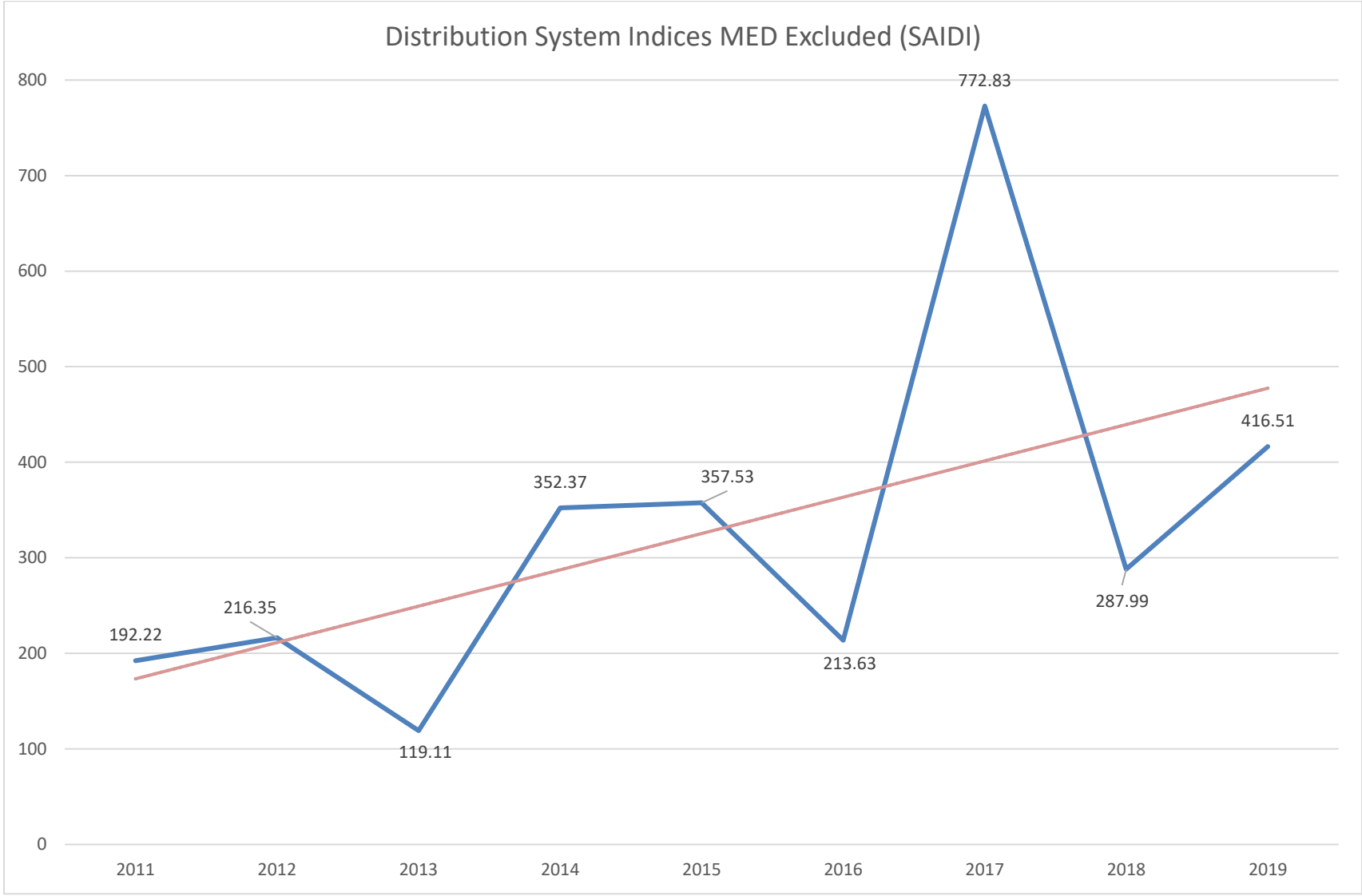
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 9 years (years in business) with linear trend line (TMED included and excluded).

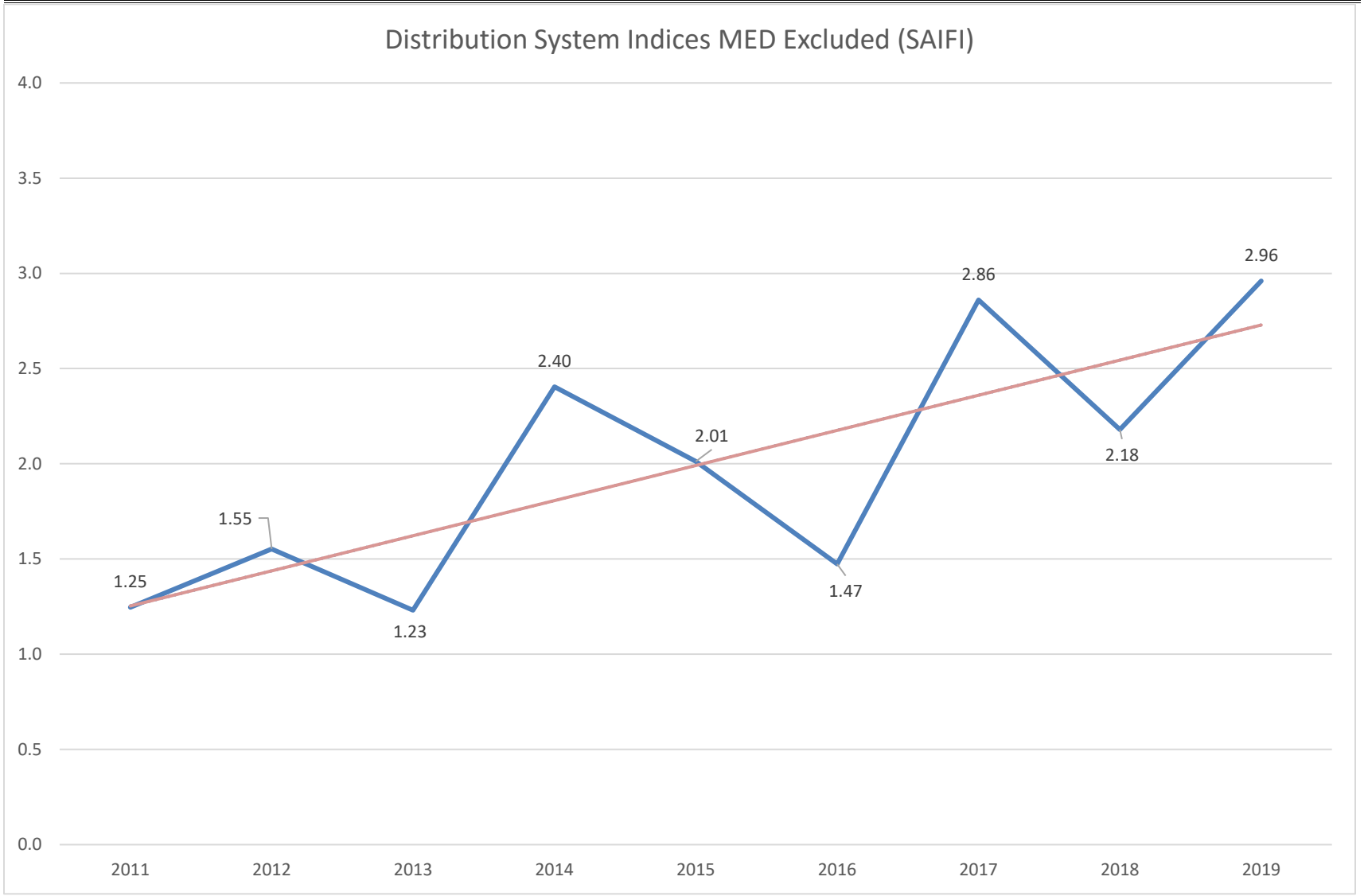

Distribution System Indices MED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
2011
2012
2013
2014
2015
2016
2017
2018
2019

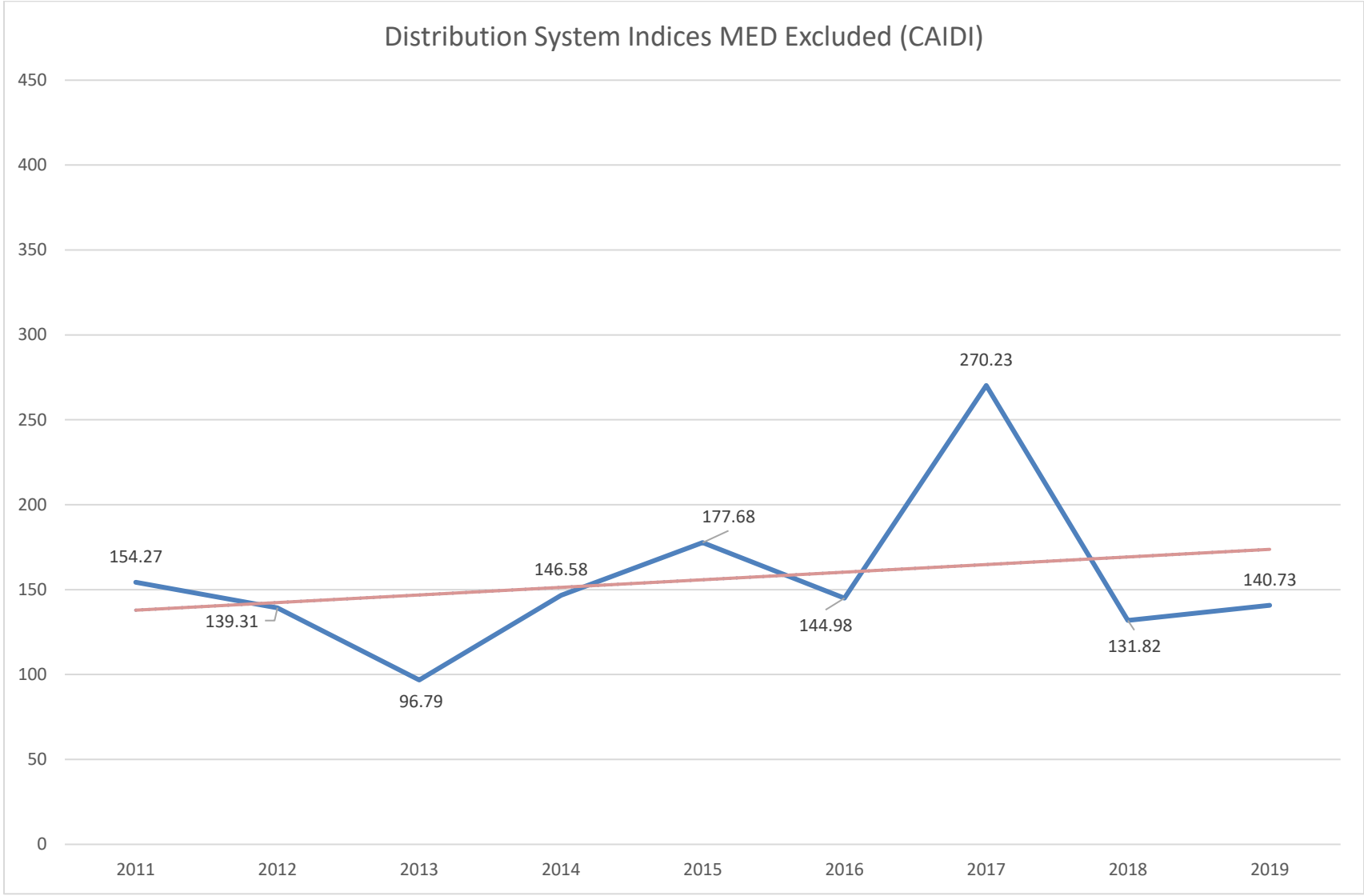

Distribution System Indices MED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.47
3.97
2.18
2.96
2011
2012
2013
2014
2015
2016
2017
2018
2019

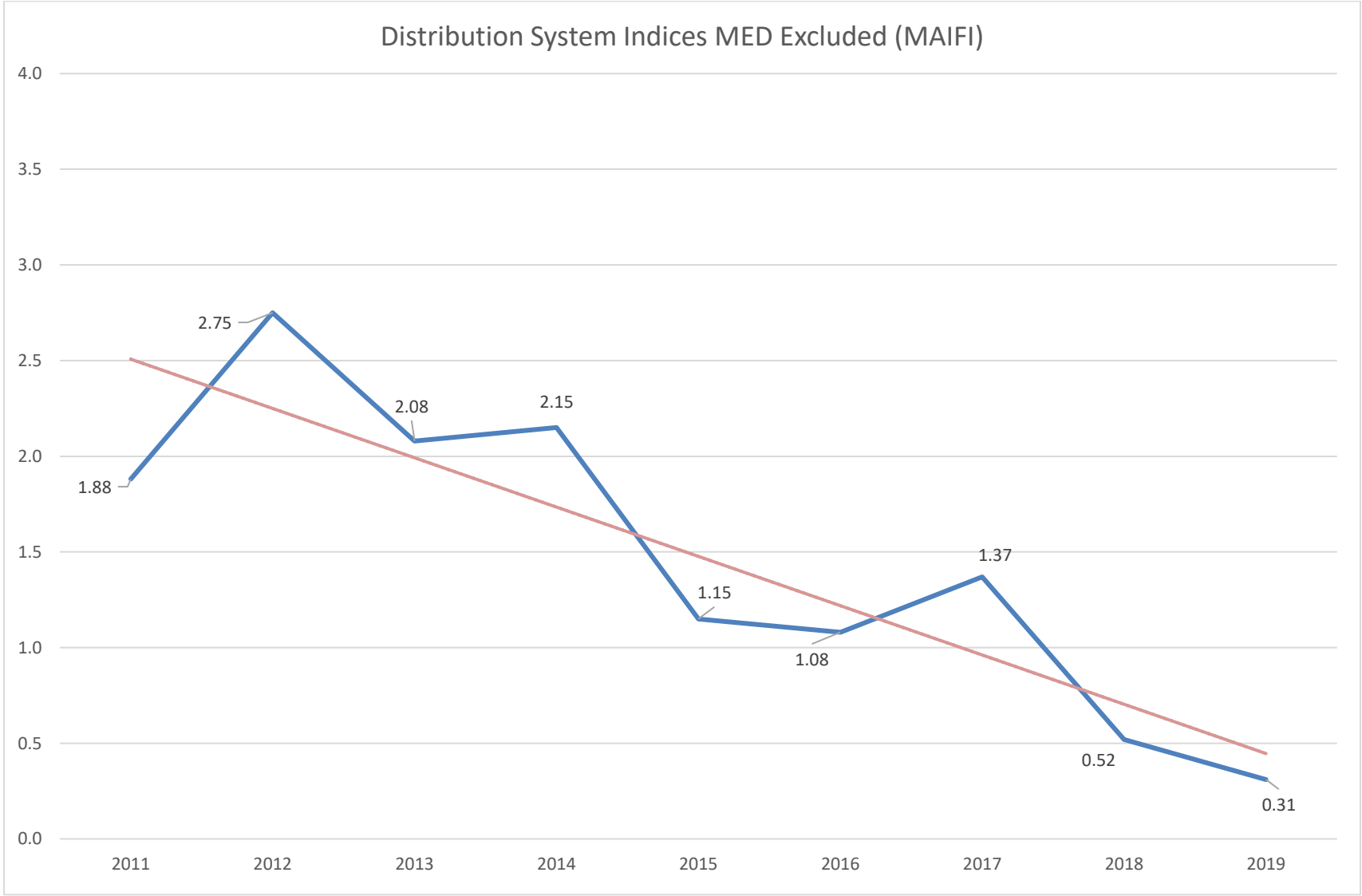

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
144.98
402.06
131.82
140.73
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
213.63
772.83
287.99
416.51
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.47
2.86
2.18
2.96
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
270.23
131.82
140.73
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.88
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019

2) Division (or District) Reliability Indices for the past 9 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

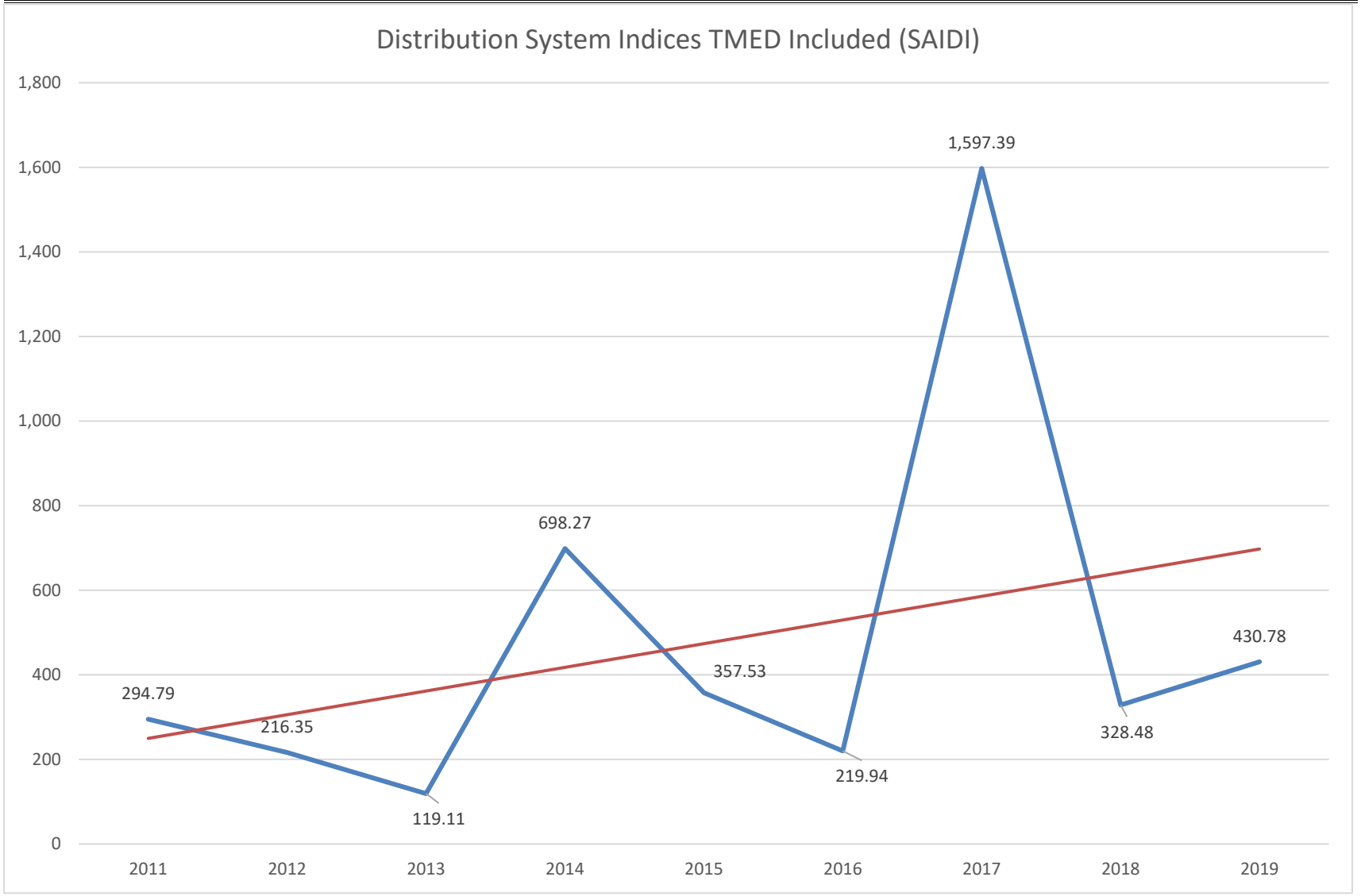
3) System and Division indices based on IEEE 1366 for the past 9 years including planned outages and including and excluding TMED

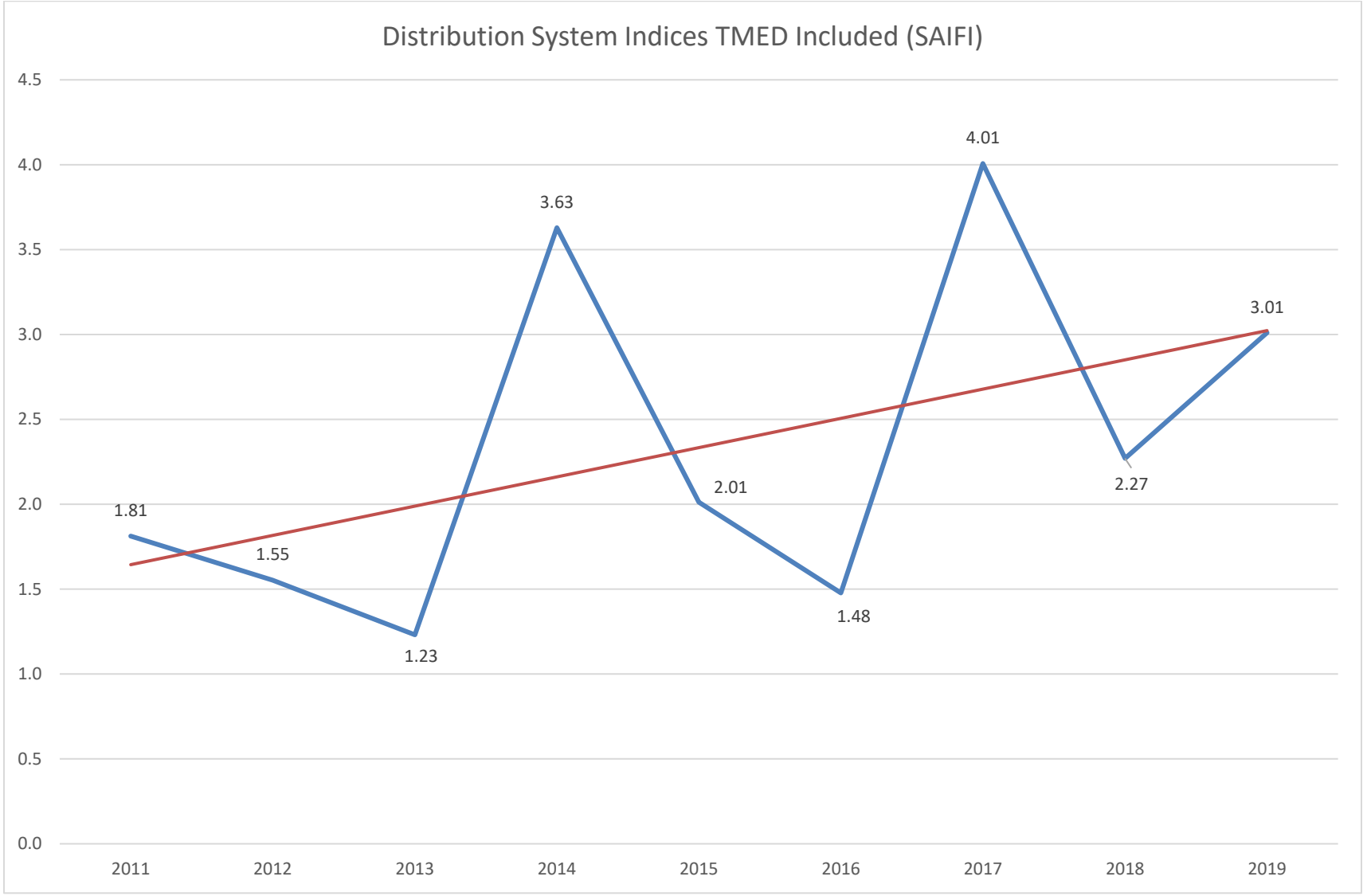
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

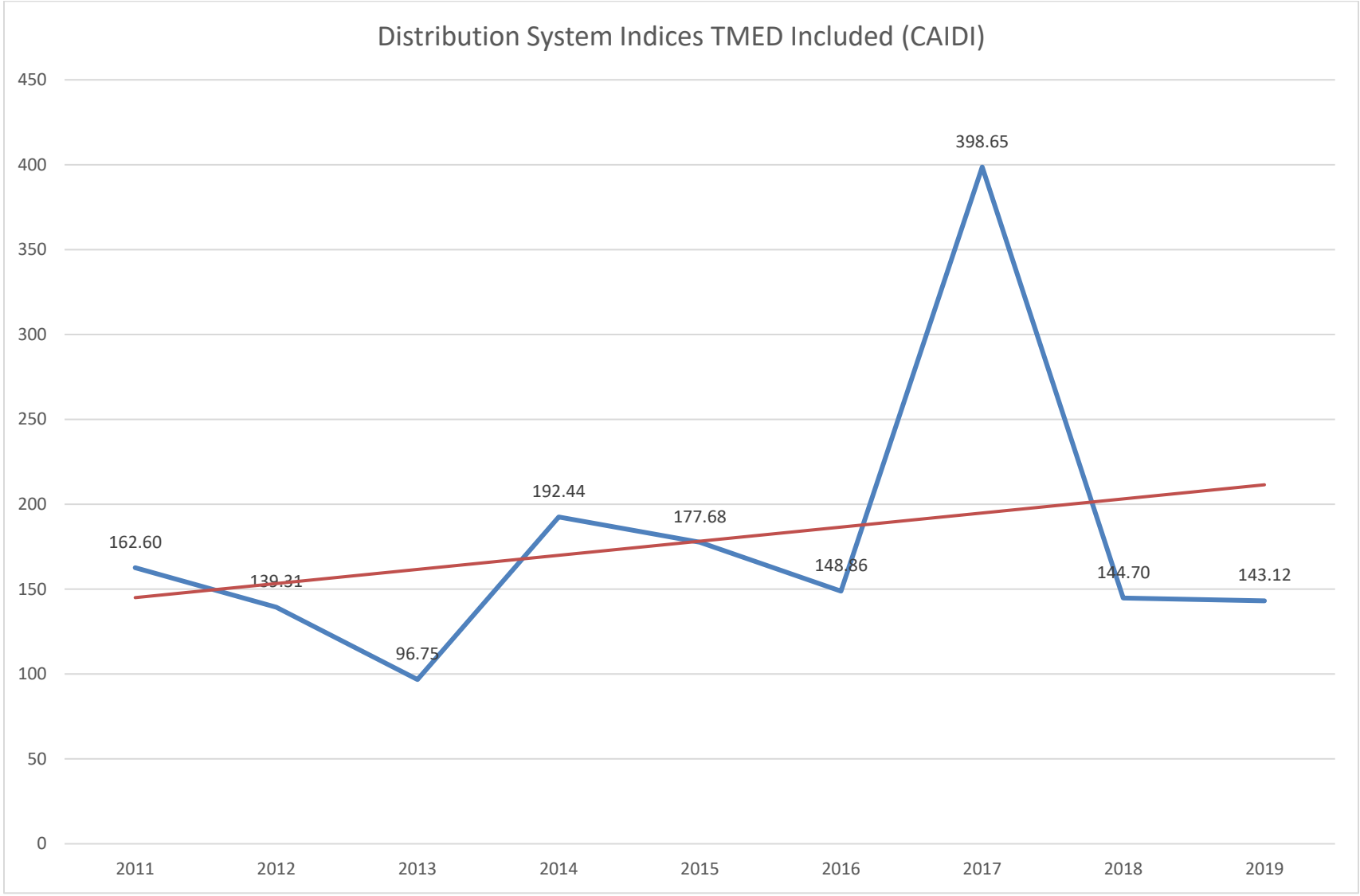
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 9 Years (Years in Business)

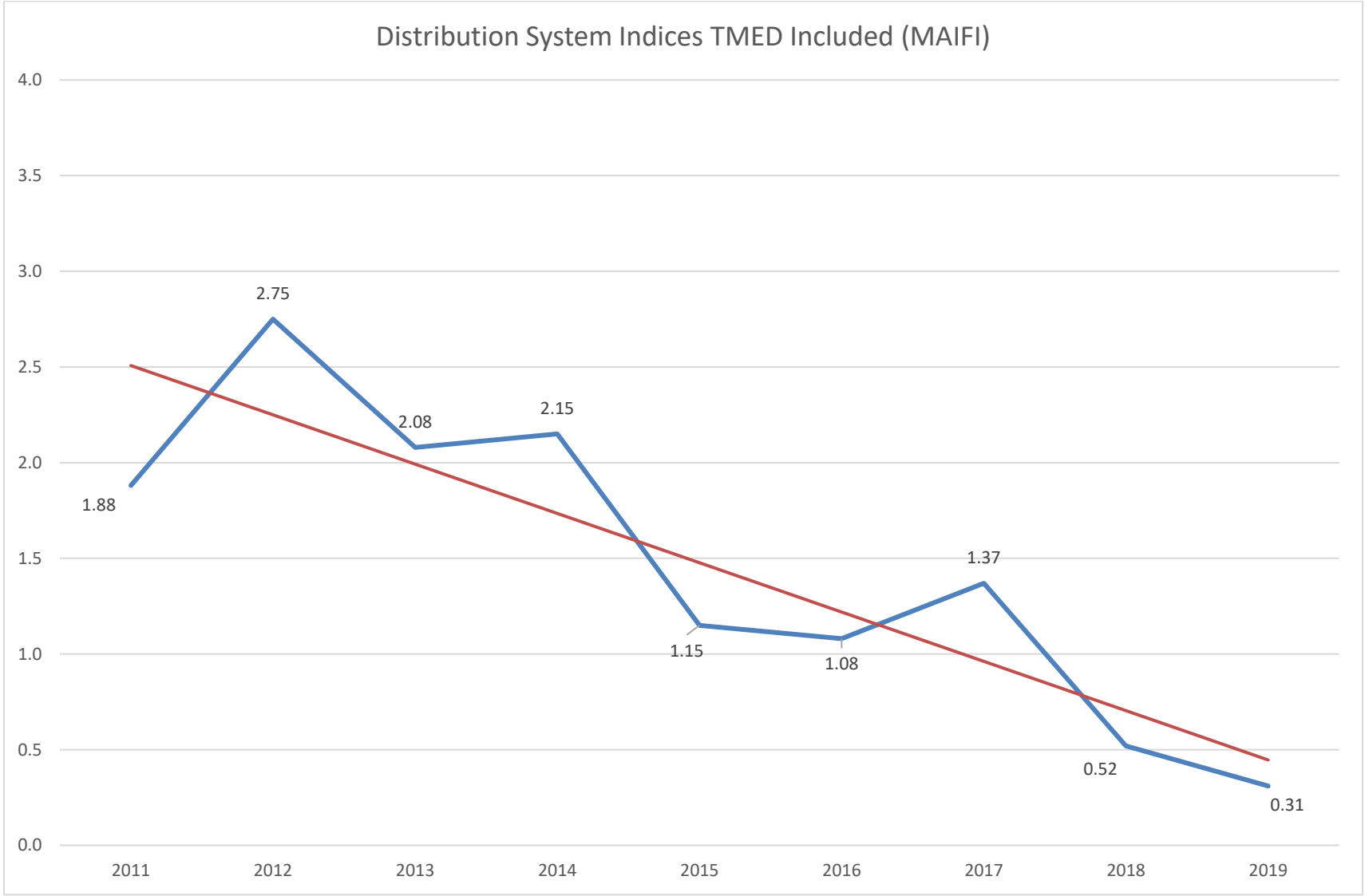
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.70	0.52	328.48	2.27	144.70	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

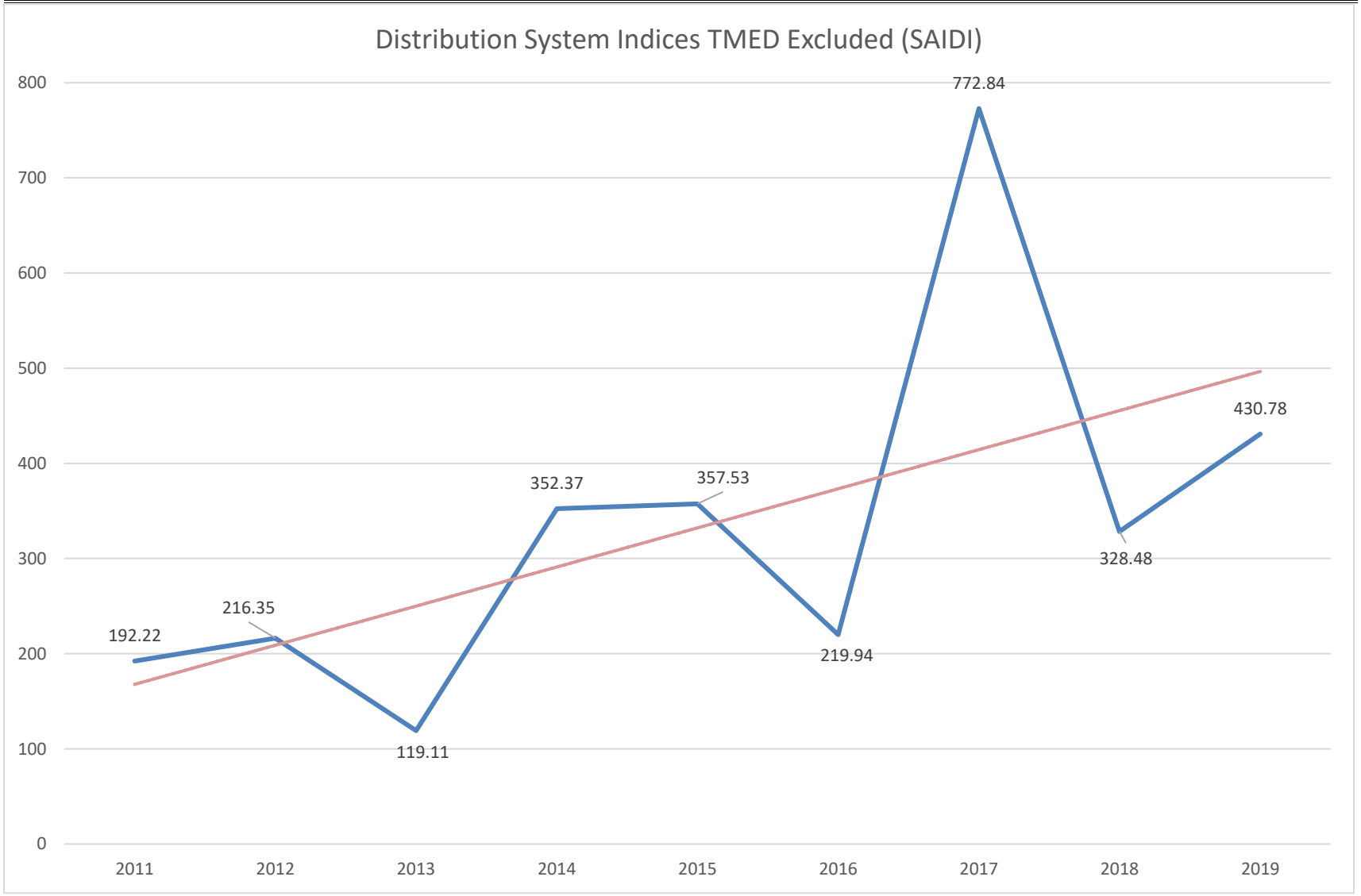
CalPeco Electric has been in business for 9 years and therefore does not have 10 years of data.


Distribution System Indices TMED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Included (SAIFI)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.48
4.01
2.27
3.01
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
398.65
144.70
143.12
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
2011
2012
2013
2014
2015
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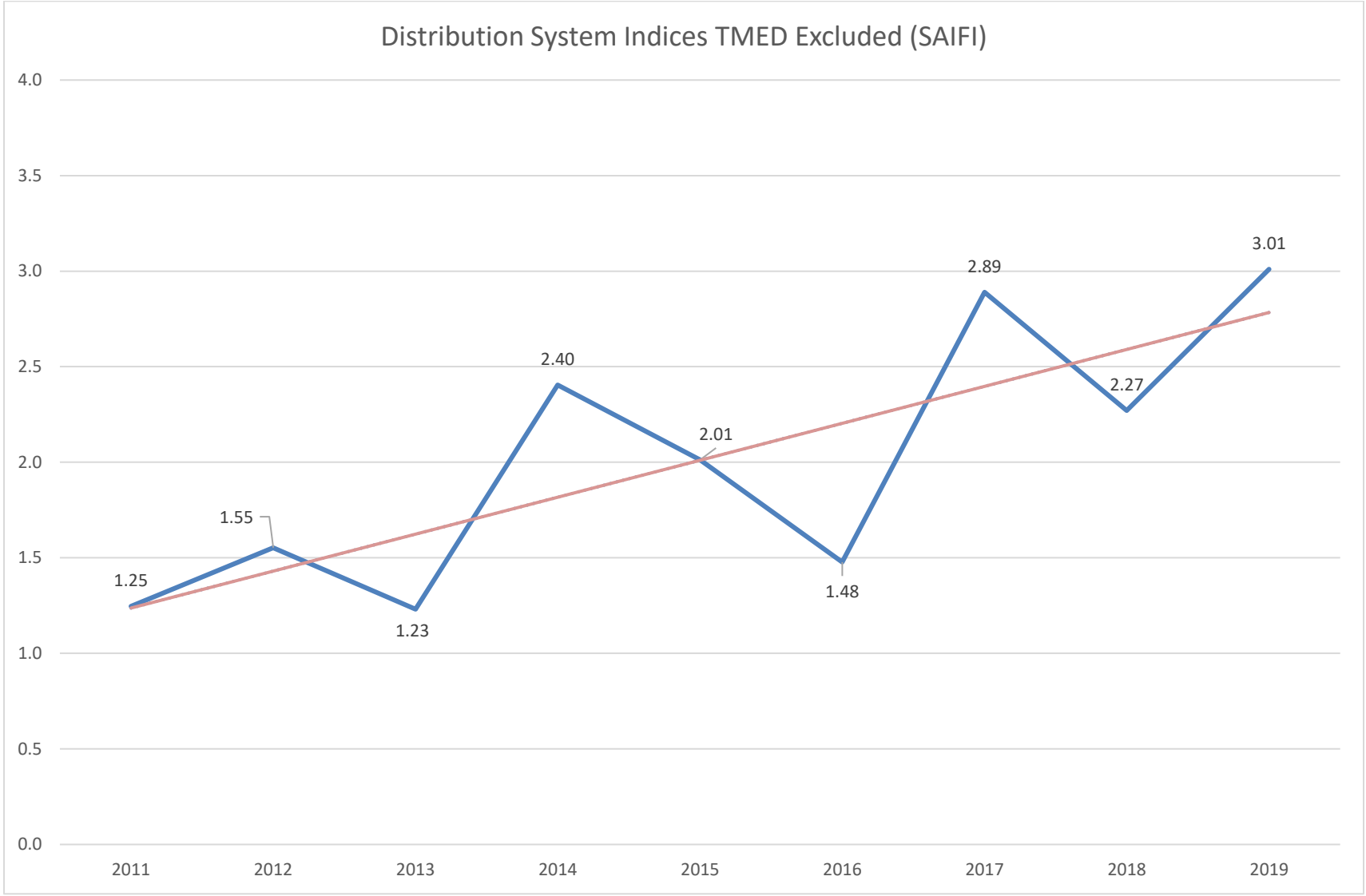
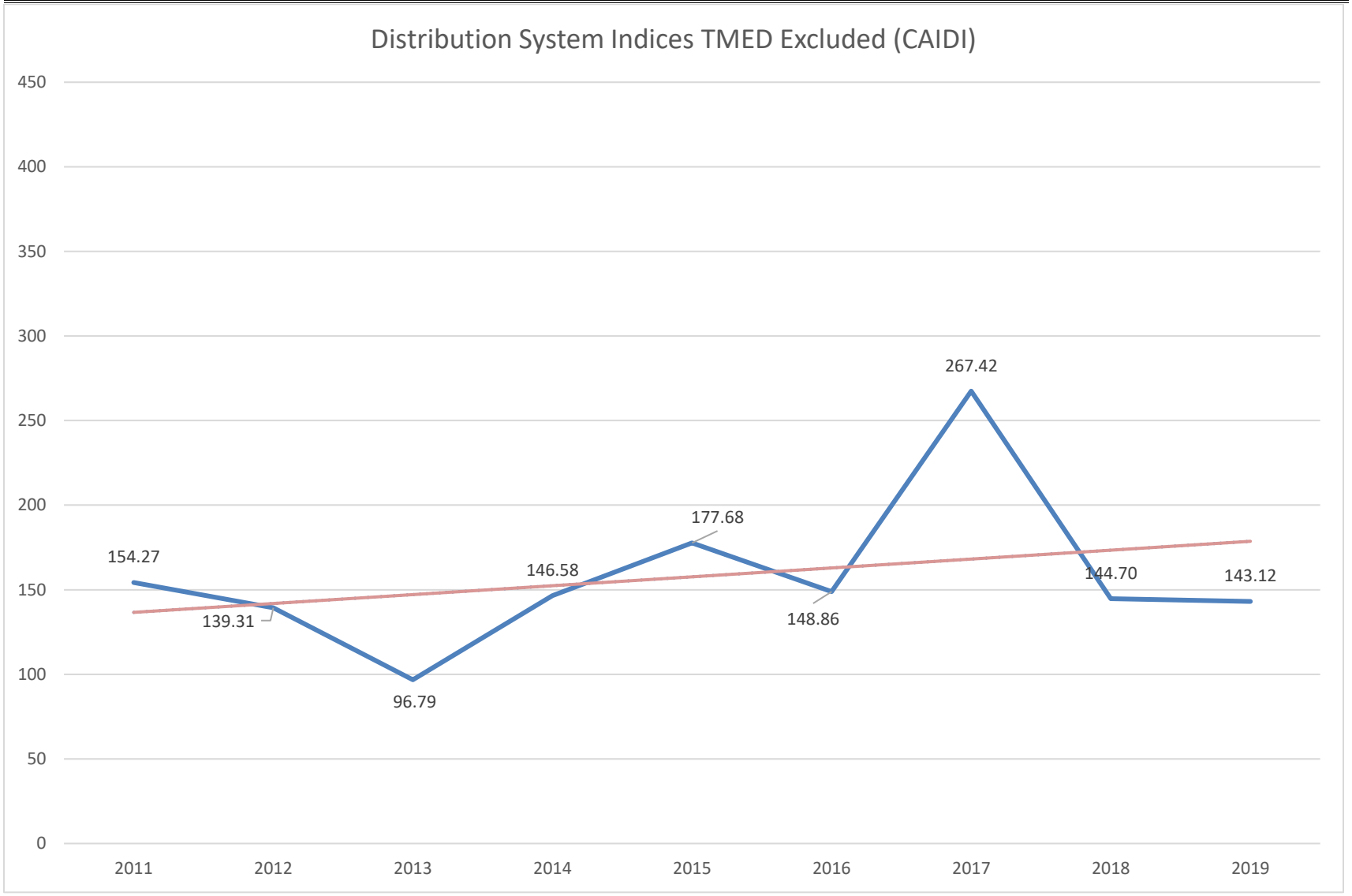
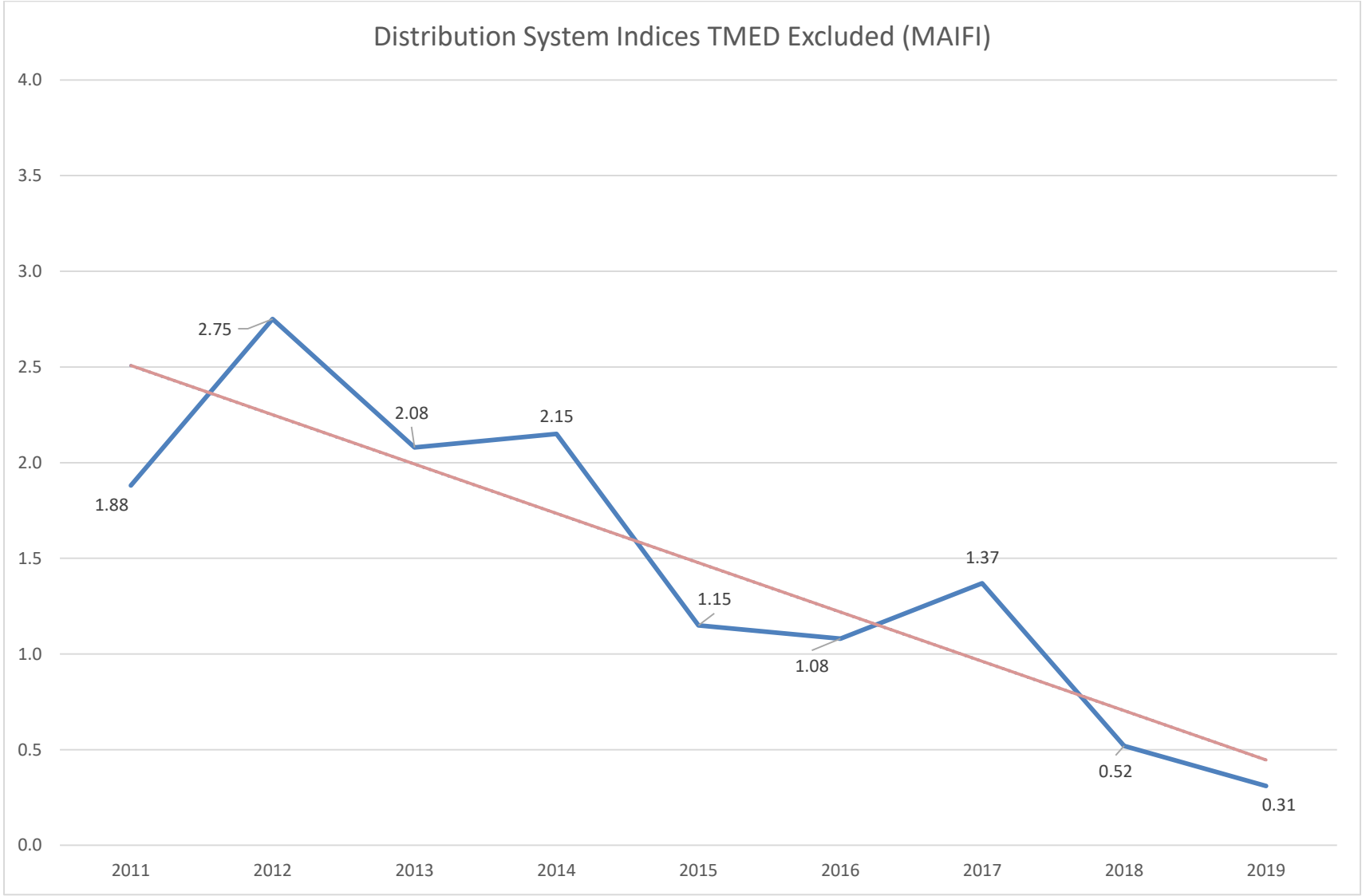
2017
2018
2019
192.22
216.35
119.11
352.37
357.53
219.94
772.84
328.48
430.78


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.48
2.89
2.27
3.01
2011
2012
2013
2014
2015
2016
2017
2018
2019

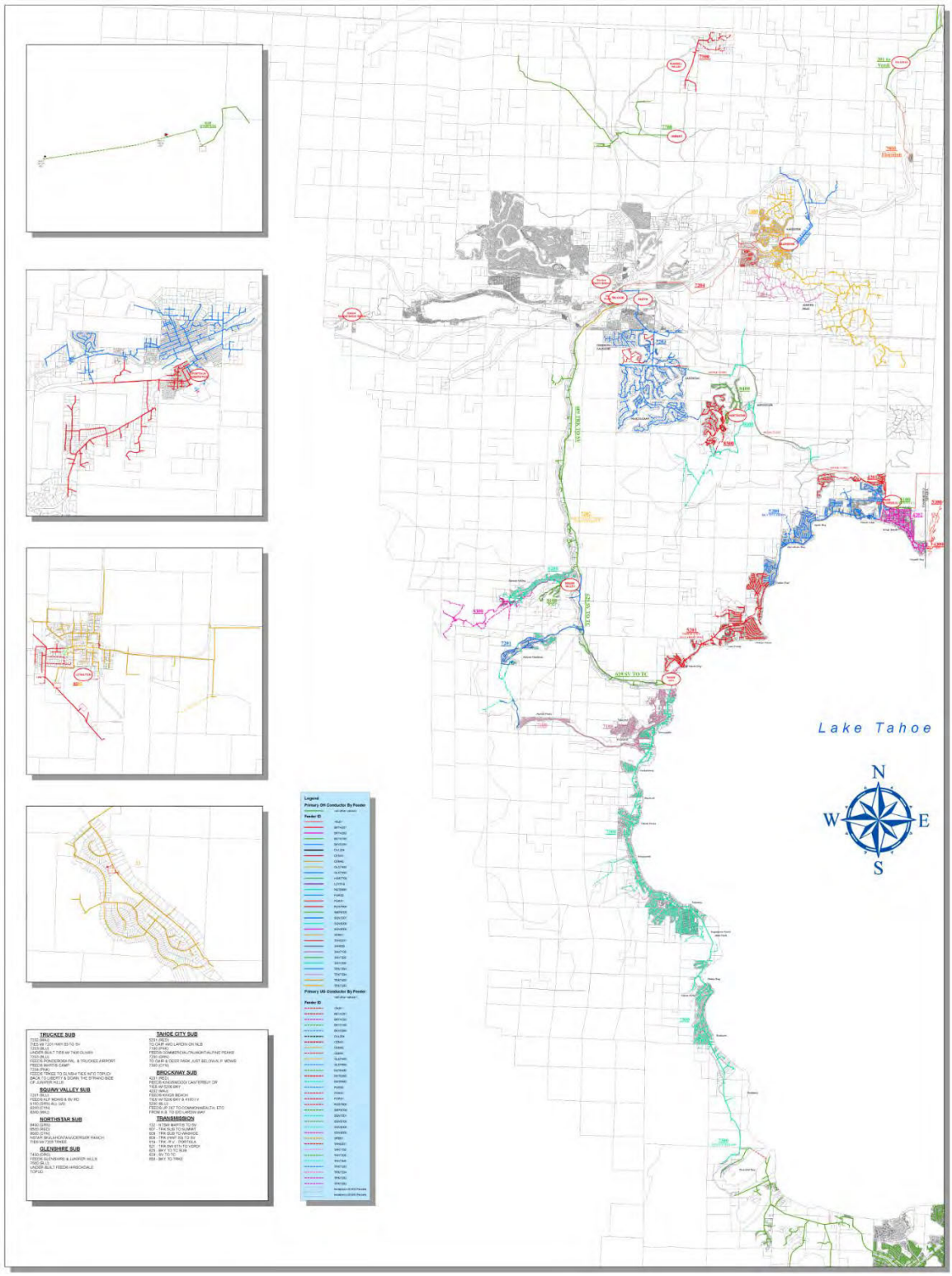

Distribution System Indices TMED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
267.42
144.70
143.12
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019

b. The number, date, and location of planned outages

Circuit	Number of Planned Outages By Year								
	2019	2018	2017	2016	2015	2014	2013	2012	2011
31		1			1				
32	1		2	1					
41				1					
201		7					1		
204	2			1					
619								1	
650					1			1	
1261	1	1							
1296		1	2		5	1			
2200	1				1	1			
2300	1	1			1	2		1	
3100	8	5	1					1	1
3101	3					2	2		
3200	3	5			1			1	
3300	8	10	2		3			2	
3400	2	4	3		5		2	4	
3500	15		6		1				
3501	3	3			2	2	4	1	1
4201	1	1		1					
4202	5	3	4				2	5	1
5100							1	1	
5200	5	4	1		4	1	1	3	
5201	8	1	5	5	4	1		1	
7100	1	2	1			1	1	4	
7200	1	1			1	1	1	2	
7201	1		4	1	2	1			
7202	3	1	1		2	3	1		
7203	3	2			2	2	4		
7300	20	14	5	6	4	16	4	5	2
7400	4	8	2	1	1				1
7600	1	1			1				1
7700						1			
7800						2			
7900	1								
8200	1	2	7	3	2	4			1
8300	1	1	2		6			2	
8400		7							
8500				1			1	2	
8600					4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	749	Topaz	70.9	76.2%	23.8%	7	3040	7.12
201*	Tahoe	64	Washoe	8.7	99.8%	0.20%	4	2931	7.83

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2018 as well as 2019. The 3 year average circuit SAIDI score remains high due to significant outages in 2017 from wildfire and severe winter storms and an outage on March 22, 2019 which lasted approx. 58hrs. If the March 22nd, 2019 outage is excluded from the data, the Topaz 1261 circuit would not have been considered a deficient circuit in 2019.

There were 25 unplanned outages in 2019 for the 1261 circuit, 3 were due to a loss of source from a third party owned substation, 6 were due to equipment/hardware failure, 3 were weather related, 1 was due to trees,1 was due to an operations error and the rest were unknown.

The historical metric for Topaz 1261:

- 2019 – 3,040.6
- 2018 – 2,393.8
- 2017 – 3,004.5
- 2016 – 1930.4

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada. Approximately 10,000ft of this line will be will be rebuilt in 2020.

The circuit performance in 2019 was higher than historical records, excluding 2017. The 2017 performance is an outlier and does not accurately reflect the condition of this circuit. Liberty expects this circuit will no longer be a deficient

circuit no later than 2021 when the 2017 data is removed from the average and the planned rebuild is complete in 2020.

The Washoe 201 circuit was noted as a deficient circuit in 2017, 2018 as well as 2019. The 3 year average circuit SAIDI score remains high due to significant outages in 2017 from wildfire and severe winter storms.

There were only 5 unplanned outages in 2019 for the 201 circuit, 4 were due to a loss of source from a third party owned substation and the 5th time the substation was de-energized due to a brush.

The historical metric for Washoe 201:

- 2019 – 2931.6
- 2018 – 2,722.9
- 2017 – 2,698.9
- 2016 – 269.2

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line in difficult terrain, sourced by an NV Energy substation in Nevada. The line has been rebuilt in 2014 and Liberty completed a voltage conversion in 2018 so that the entire circuit is now 24.9kV.

The circuit performance in 2019 was similar to historical records, excluding 2017. The 2017 performance is an outlier and does not accurately reflect the condition of this circuit. Liberty expects this circuit will no longer be a deficient circuit no later than 2020 when the 2017 data is removed from the average.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	10/1/2019	Third Party - Contractor Dig In	Lake Tahoe	10490	51.79	0.22223
2	2/22/2019	Equipment Failure	Lake Tahoe	8560	35.36	0.1814
3	10/3/2019	Third Party - Contractor Dig In	Lake Tahoe	7841	1.83	0.1661
4	2/26/2019	Hardware Failure	Lake Tahoe	4485	19.96	0.0950
5	1/18/2019	Tree	Lake Tahoe	4448	8.93	0.0942
6	3/6/2019	Hardware Failure	Lake Tahoe	4448	4.62	0.0942
7	11/11/2019	Animal	Lake Tahoe	4245	3.24	0.0899
8	9/21/2019	Third Party – Line Contact	Lake Tahoe	3712	2.05	0.0786
9	6/7/2019	Animal	Lake Tahoe	3529	2.09	0.0748
10	6/7/2019	Tree	Lake Tahoe	3507	6.76	0.0743

*Based on customer impact

7) Summary list of 2019 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2018 = 171.00

CalPeco Electric did not experience an event in 2019 where the daily SAIDI was higher than the calculated TMED.

8) Historical 10 largest unplanned outage events for the past 8 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No
4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

9) Number of customer inquiries on reliability data and the number of days per response

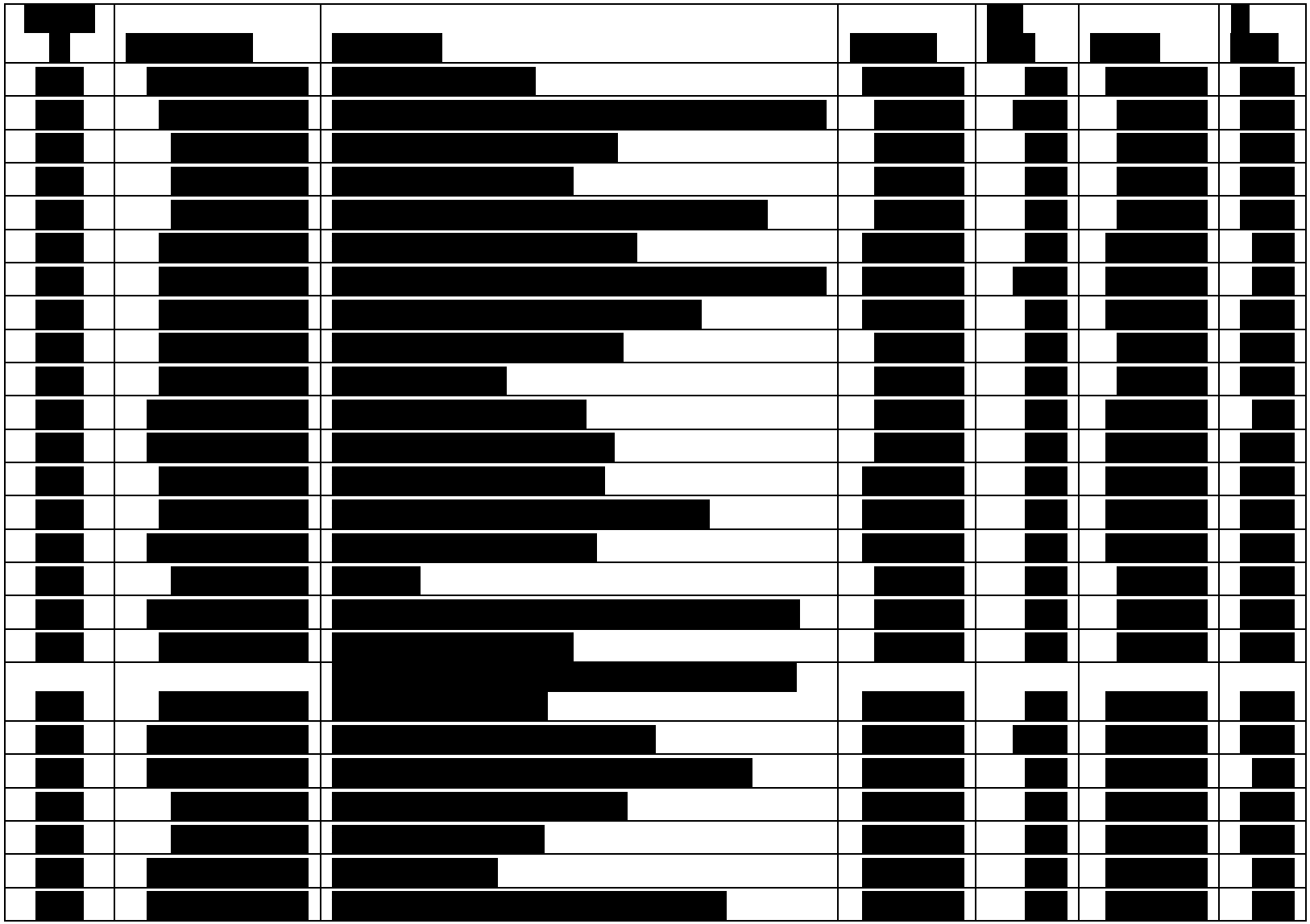
CalPeco Electric did not receive any reliability inquiries in 2019.

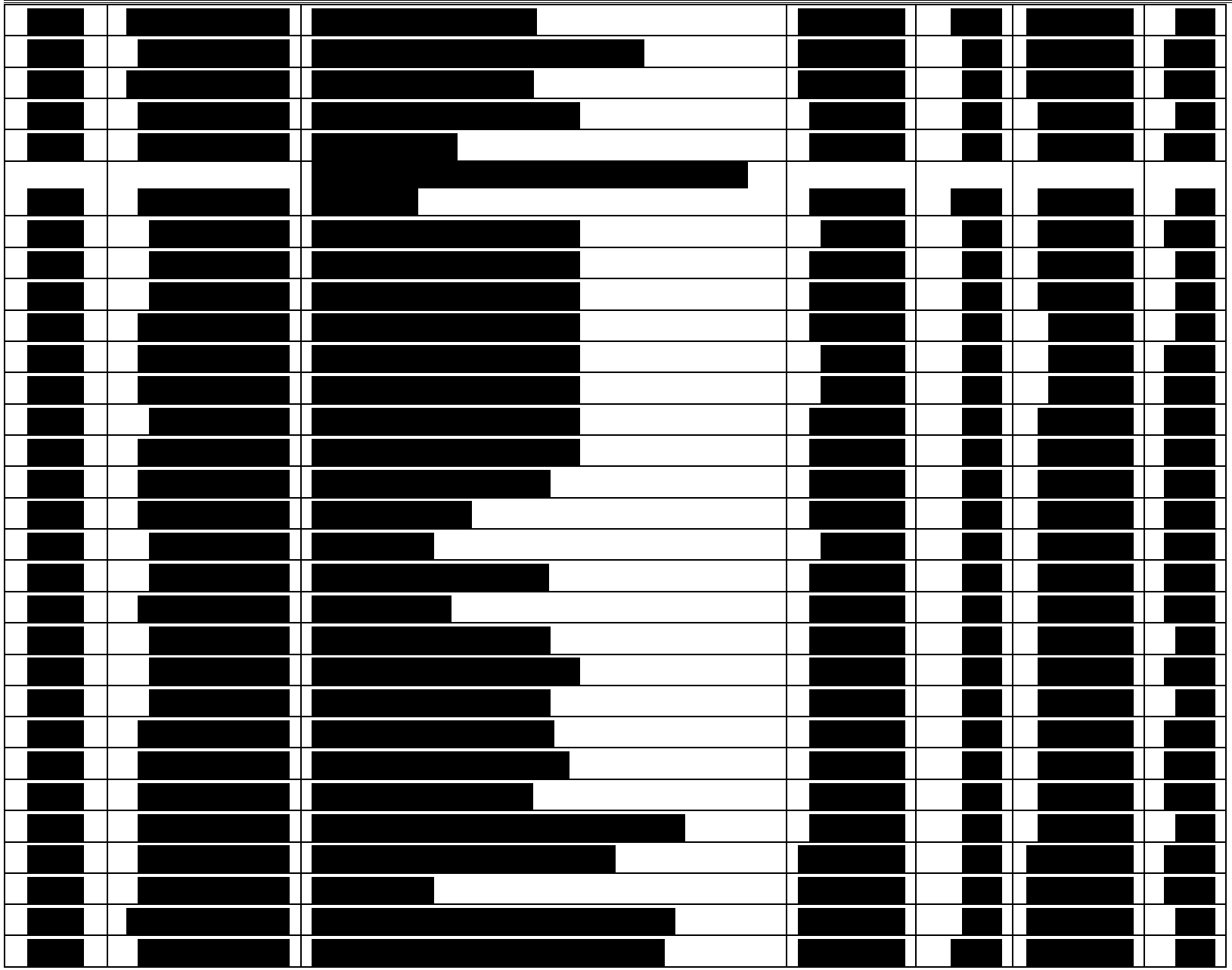
Date Received	Date Responded	Description of Inquiry

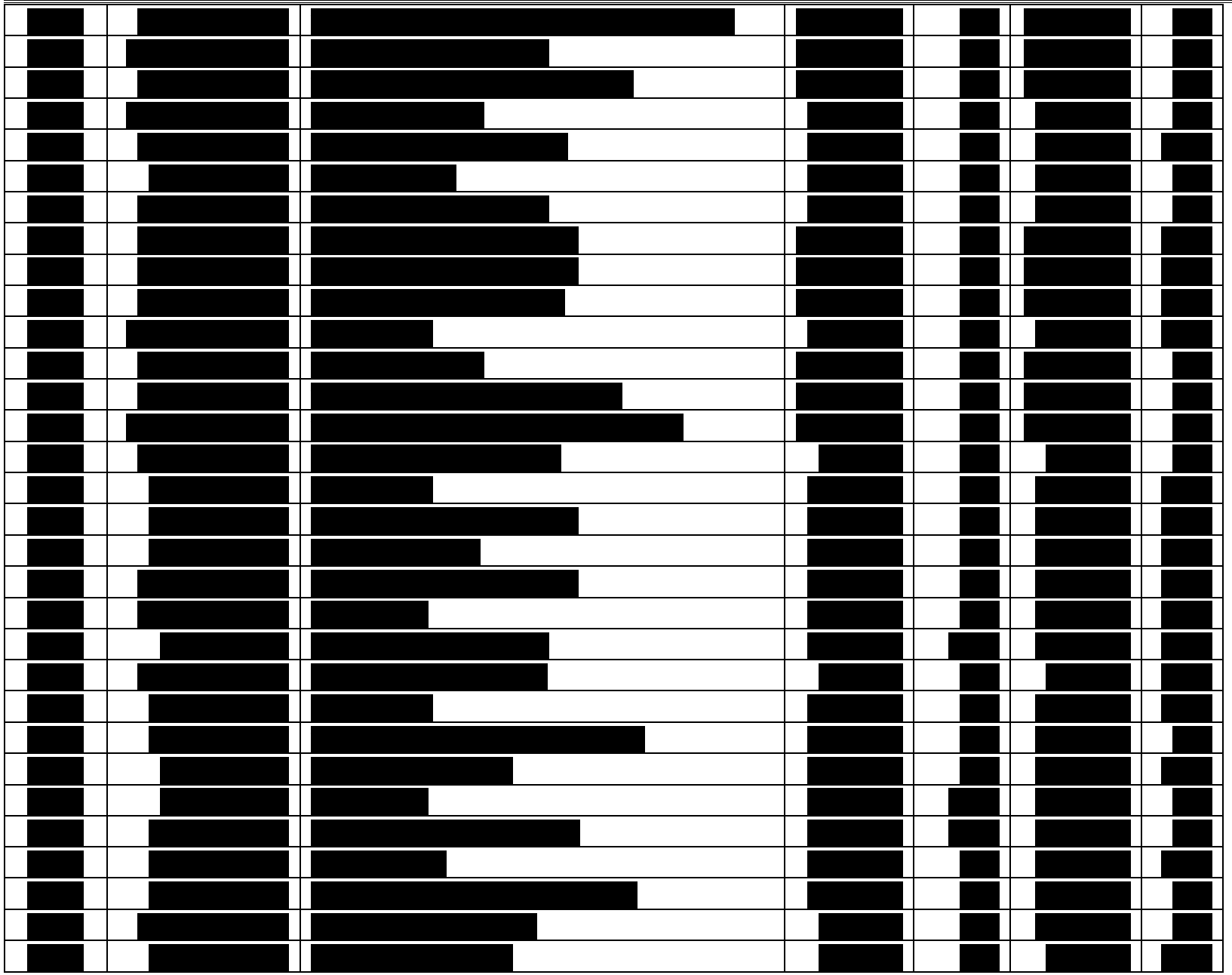
10) List of PSPS's in 2019

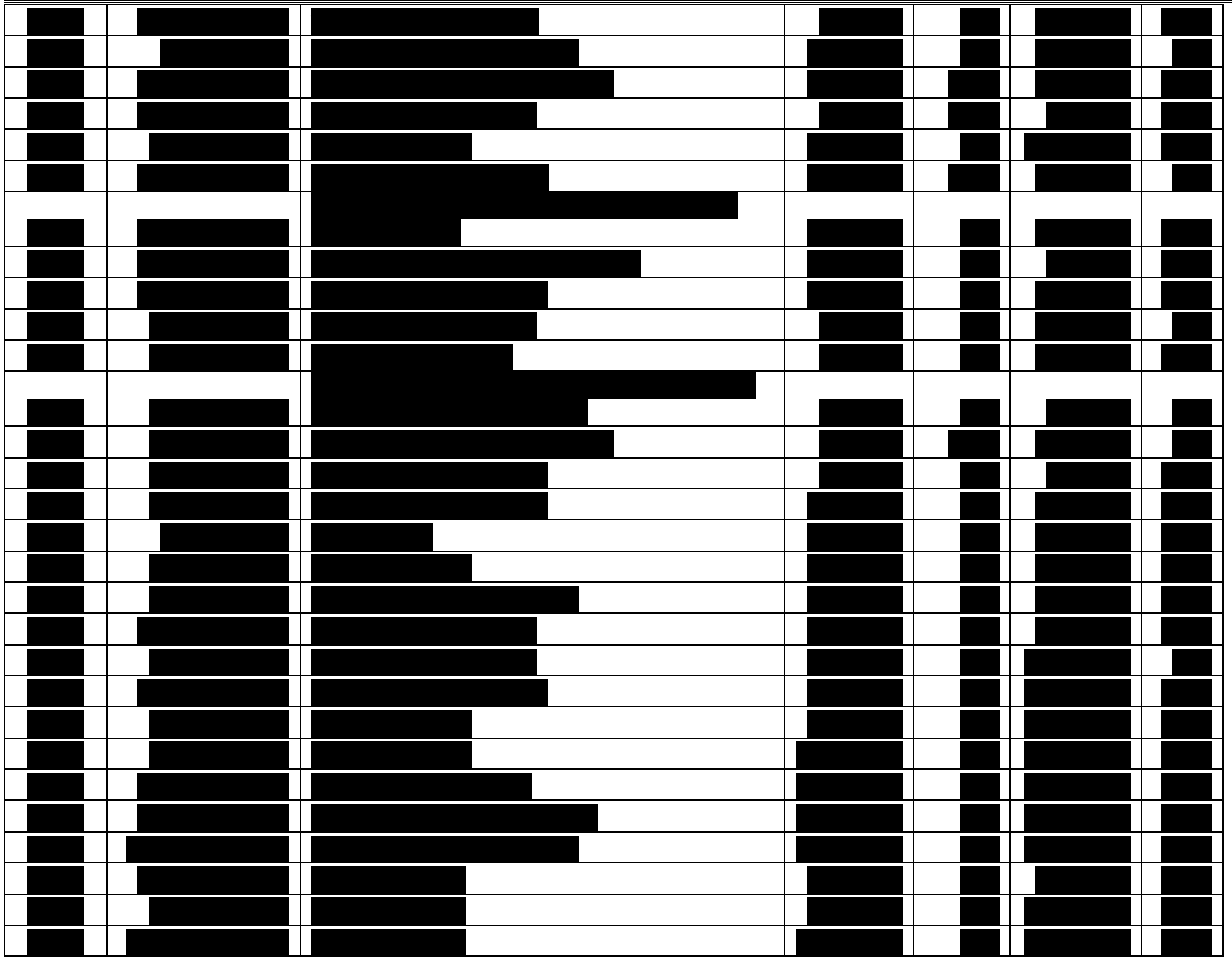
CalPeco Electric did not have any PSPS events in 2019.

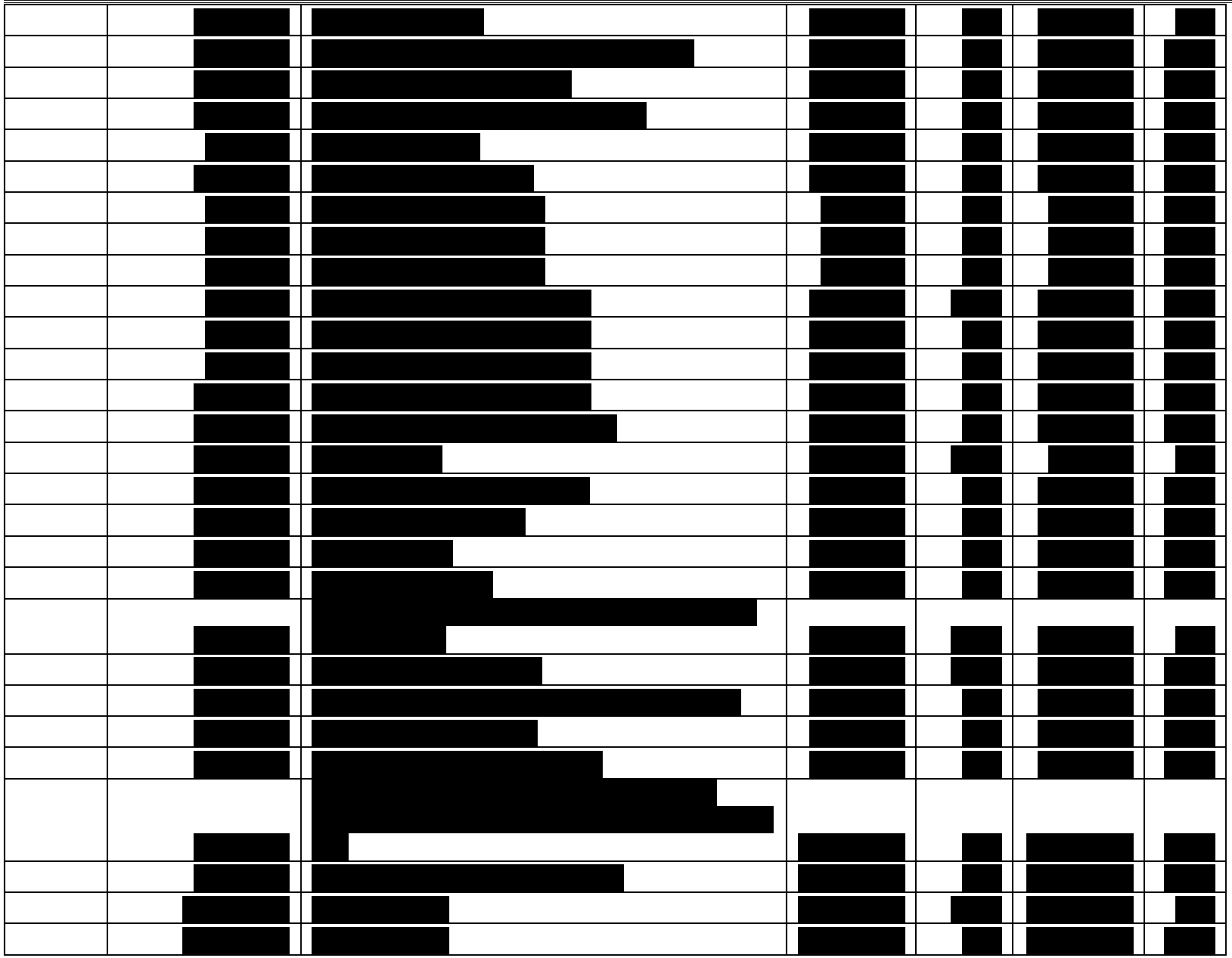
Appendix A: 8 Years of Planned Outage Data -- PUBLIC VERSION --

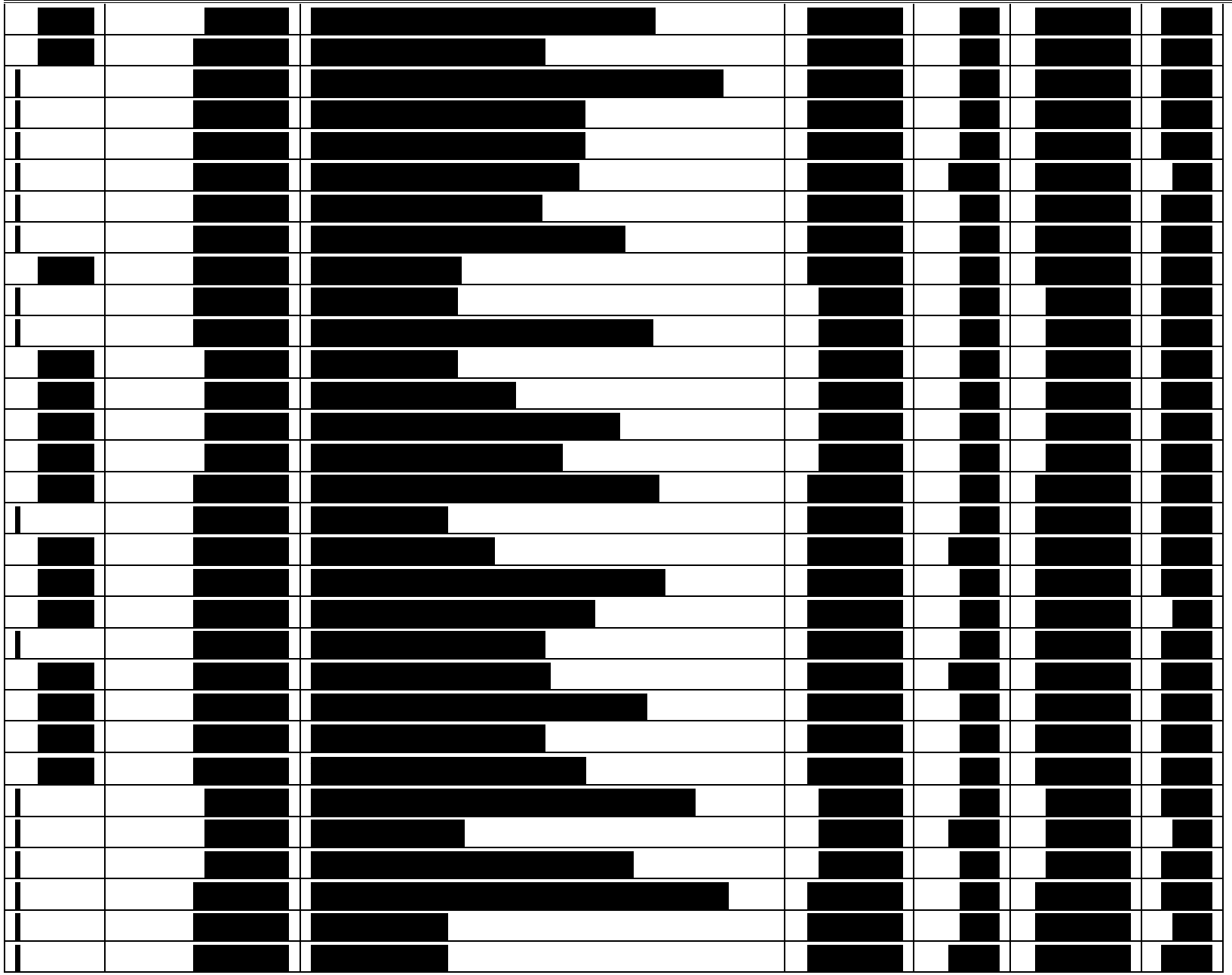












ATTACHMENT 7

Liberty's Overhead Stringing and Sagging Standards in effect as of November 17, 2020

OVERHEAD DISTRIBUTION CONDUCTOR STRINGING GUIDE

1.0 INDEX

2.0 PURPOSE

This standard provides a set of tables containing the sagging data necessary to string overhead distribution conductors used for new construction. The condensed Tables (sheets 5.4.3 thru 9), can be used when the actual span is equal to the ruling span. When the span to be sagged does not equal the ruling span, consult the detailed sag Tables on sheets 5.5.10 thru 20.

3.0 GENERAL

3.1 DEFINITION OF TERMS

Conductor Loading- Maximum conductor loading produced by the combined effect of the weight of conductor, ice load and wind pressure acting on the conductors. There are one classification of conductor loading.

a. **G.O. 95 Heavy**- California locations above 3000' and includes conductor weight with 1/2 inch of 0° F ice and 6 lbs./sq. ft. of wind pressure.

Tables containing sag data are provided for G.O. 95 heavy loading conditions. Lake Tahoe, Portola, and other California locations above 3000 feet shall be considered HEAVY loading because of the severe weather conditions to which these areas are subjected to.

Ruling Span- The ruling span is the theoretical span length in which the changes in conductor tension due to changes in temperature and loading will most nearly agree with the average tension in a series of spans of varying length, and with flexible supports between dead ends. The formula for ruling span is:

Ruling Span = $$\sqrt{\frac{s_1^3 + s_2^3 + s_3^3 + \ldots + s_n^3}{s_1 + s_2 + s_3 + \ldots + s_n}}$$

Where: n = span number
s = span length in feet

If the maximum span length is within 10% of the average span length, then the following approximation can be used.

Ruling Span - The average span length (not including deadend spans) and adding 2/3 of the difference between the average and the maximum, non-deadended, span.

The span length that results from the above formulas is that span length most representative of all the span lengths in a section of line.

Tension- The tension is the mechanical stress on the conductor expressed in pounds. The ultimate tension is the maximum pounds of force that the conductor can be subjected to before it will fail. For the following tables the maximum loading (tension)shall not exceed 50% (25% for 795 AA Arbutus) of the ultimate strength of the conductor. Also, the conductor tension, without external loading, shall not exceed the following percentages of ultimate strength:

	Percent Strength	Medium	Heavy
Initial unloaded tension	33.3	15°F	0°F
Final unloaded tension	25.0	15°F	0°F

Span- The actual span distance between the two poles. If the span distance falls between two values on the table, it may be necessary to interpolate in order to find the proper sag, depending upon whether or not the difference between the upper and lower sag values is significantly large.

Temperature- The amount of sag and tension in the conductor will be dependent upon the temperature, in that the conductor will stretch to such a degree as defined by its thermal coefficient of expansion. It was, therefore, necessary to provide sag values in the tables based on temperature. The temperatures for which data is provided range from 0°F to 120°F at selected intervals.

Initial Sag- Initial sags are the sags at which new, or previously unstressed, conductors shall be strung.

4.0 USE OF STRINGING SAG TABLES

4.1 Tables are provided for all three distribution conductors used for new construction, (#2 ACSR, 397.5 AA, and 795 AA), with ruling spans ranging from 200 feet to 400 feet, at 50-foot intervals, for the conductors shown.

4.2 In order to use the Table(s), the foreman will need to know the type of conductor, the ruling span, the span distance and the temperature. The temperature should be determined just before the

conductor(s) are strung. Having obtained the above information, he can find the proper Table by conductor and ruling span. Once he has the right Table, the sag can be found by finding the span distance, then reading across horizontally to the appropriate temperature. Refer to the examples given below.

5.0 EXAMPLES

5.1 **Given:** Loading - G.O. 95 Heavy
Conductor - #2 ACSR Sparrow
Ruling Span - 400 feet
Actual Span - 230 feet
Temperature - 30°F (May be necessary to interpolate)

Find: Correct Conductor Sag

Solution: 1. Find proper table containing G.O. 95 HEAVY loading for #2 ACSR and 400-foot ruling span. (See Sheet #5.5.10 for sag table)
2. Find actual span distance of 230 feet.
3. Read across horizontally and read proper sag under 20°F column and the 40° column.
   20°: Sag= 24 inches
   40°: Sag= 27 inches

Interpolation provides the following:

Sag= 25.5 inches

6.0 SAG TABLES

G.O. 95 HEAVY LOADING RULING SPAN: 200'			TEMPERATURE (°F)				
			20°	40°	60°	80°	100°
CONDUCTORS	#2 ACSR	INITIAL SAG TENSION (lbs.)	795	691	583	473	369
		SAG (inches)	7	8	9	12	15
	2/0 AA	INITIAL SAG TENSION (lbs.)	495	362	273	219	185
		SAG (inches)	15	21	27	34	41
	2/0 ACSR	INITIAL SAG TENSION (lbs.)	1336	1144	951	765	601
		SAG (inches)	8	10	12	14	18
	4/0 AA	INITIAL SAG TENSION (lbs.)	991	742	543	414	336
		SAG (inches)	12	16	22	29	36
	397.5 AA	INITIAL SAG TENSION (lbs.)	1822	1389	1039	800	649
		SAG (inches)	12	16	22	28	34
	795 AA *	INITIAL SAG TENSION (lbs.)	1629	1317	1115	977	877
		SAG (inches)	27	34	40	46	51

***Indicates tension calculated at 25% ultimate. All other conductors calculated at 50% ultimate. Shaded conductors are not for new construction. Sag tables provided for maintenance only.**

G.O. 95 HEAVY LOADING RULING SPAN: 250'			TEMPERATURE (ºF)				
			20º	40º	60º	80º	100º
CONDUCTORS	#2 ACSR	INITIAL SAG TENSION (lbs.)	854	753	649	543	440
		SAG (inches)	10	11	13	16	19
	2/0 AA	INITIAL SAG TENSION (lbs.)	299	249	216	192	175
		SAG (inches)	39	47	54	61	67
	2/0 ACSR	INITIAL SAG TENSION (lbs.)	1406	1219	1033	854	695
		SAG (inches)	12	14	17	20	25
	4/0 AA	INITIAL SAG TENSION (lbs.)	867	665	521	426	364
		SAG (inches)	21	28	36	44	51
	397.5 AA	INITIAL SAG TENSION (lbs.)	1923	1514	1182	944	784
		SAG (inches)	18	23	30	37	45
	795 AA *	INITIAL SAG TENSION (lbs.)	1518	1315	1168	1058	973
		SAG (inches)	46	53	60	66	72

***Indicates tension calculated at 25% ultimate. All other conductors calculated at 50% ultimate. Shaded conductors are not for new construction. Sag tables provided for maintenance only.**

G.O. 95 HEAVY LOADING RULING SPAN: 300'			TEMPERATURE (ºF)				
			20º	40º	60º	80º	100º
CONDUCTORS	#2 ACSR	INITIAL SAG TENSION (lbs.)	670	571	45	390	320
		SAG (inches)	18	22	26	32	38
	2/0 AA	INITIAL SAG TENSION (lbs.)	231	210	193	180	169
		SAG (inches)	73	81	87	94	100
	2/0 ACSR	INITIAL SAG TENSION (lbs.)	1475	1294	1113	941	785
		SAG (inches)	17	19	22	26	31
	4/0 AA	INITIAL SAG TENSION (lbs.)	642	529	451	396	356
		SAG (inches)	42	51	60	68	75
	397.5 AA	INITIAL SAG TENSION (lbs.)	1946	1569	1265	1043	886
		SAG (inches)	26	32	40	48	57
	795 AA *	INITIAL SAG TENSION (lbs.)	1454	1313	1203	1115	1043
		SAG (inches)	69	77	84	90	97

***Indicates tension calculated at 25% ultimate. All other conductors calculated at 50% ultimate. Shaded conductors are not for new construction. Sag tables provided for maintenance only.**

G.O. 95 HEAVY LOADING RULING SPAN: 350'			TEMPERATURE (ºF)				
			20º	40º	60º	80º	100º
CONDUCTORS	#2 ACSR	INITIAL SAG TENSION (lbs.)	448	376	319	276	243
		SAG (inches)	37	44	52	61	69
	2/0 AA	INITIAL SAG TENSION (lbs.)	204	192	182	174	166
		SAG (inches)	113	120	127	133	139
	2/0 ACSR	INITIAL SAG TENSION (lbs.)	1543	1366	1192	1024	871
		SAG (inches)	22	25	28	33	39
	4/0 AA	INITIAL SAG TENSION (lbs.)	521	460	414	379	351
		SAG (inches)	70	80	88	97	104
	397.5 AA	INITIAL SAG TENSION (lbs.)	1933	1590	1318	1115	967
		SAG (inches)	35	43	52	61	71
	795 AA *	INITIAL SAG TENSION (lbs.)	1415	1311	1226	1155	1095
		SAG (inches)	97	105	112	119	125

***Indicates tension calculated at 25% ultimate. All other conductors calculated at 50% ultimate. Shaded conductors are not for new construction. Sag tables provided for maintenance only.**

G.O. 95 HEAVY LOADING RULING SPAN: 400'			TEMPERATURE (ºF)				
			20º	40º	60º	80º	100º
CONDUCTORS	#2 ACSR	INITIAL SAG TENSION (lbs.)	306	272	246	225	208
		SAG (inches)	71	80	89	97	105
	2/0 AA	INITIAL SAG TENSION (lbs.)	190	182	176	170	164
		SAG (inches)	159	165	172	178	184
	2/0 ACSR	INITIAL SAG TENSION (lbs.)	1599	1427	1257	1094	945
		SAG (inches)	27	31	35	40	47
	4/0 AA	INITIAL SAG TENSION (lbs.)	460	423	393	368	348
		SAG (inches)	104	113	122	130	138
	397.5 AA	INITIAL SAG TENSION (lbs.)	1690	1426	1225	1074	960
		SAG (inches)	53	63	73	73	93
	795 AA *	INITIAL SAG TENSION (lbs.)	1389	1310	1243	1184	1133
		SAG (inches)	129	137	144	151	158

***Indicates tension calculated at 25% ultimate. All other conductors calculated at 50% ultimate. Shaded conductors are not for new construction. Sag tables provided for maintenance only.**

STRINGING SAG TABLE

CONDUCTOR: *SPARROW / #2 ACSR* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.091*

RULING SPAN: *200.0* TENSION: *50% ULT TENSION- 1395#*

	INITIAL SAG TENSION (lbs.)				
	795	691	583	473	369
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	0
40	0	0	0	0	1
50	0	0	1	1	1
60	1	1	1	1	1
70	1	1	1	1	2
80	1	1	1	2	2
90	1	2	2	2	3
100	2	2	2	3	4
110	2	2	3	3	4
120	2	3	3	4	5
130	3	3	4	5	6
140	3	4	5	6	7
150	4	4	5	6	8
160	4	5	6	7	9
170	5	6	7	8	11
180	6	6	8	9	12
190	6	7	8	10	13
200	7	8	9	12	15
210	8	9	10	13	16
220	8	10	11	14	18
230	9	10	12	15	20
240	10	11	13	17	21
250	11	12	15	18	23
260	12	13	16	20	25
270	13	14	17	21	27
280	13	15	18	23	29
290	14	17	20	24	31
300	15	18	21	26	33
310	17	19	23	28	36
320	18	20	24	30	38
330	19	22	25	31	40
340	20	23	27	33	43
350	21	24	29	35	45
360	22	26	30	37	48
370	24	27	32	40	51
380	25	29	34	42	53
390	26	30	36	44	56
400	27	32	37	46	59
410	29	33	39	49	62
420	30	35	41	51	65
430	32	37	43	53	68
440	33	38	45	56	72
450	35	40	47	58	75

STRINGING SAG TABLE

CONDUCTOR: *SPARROW / #2 ACSR*
CONDUCTOR WT (lbs/ft): *.091*
RULING SPAN: *250.0*
LOADING: *G.O.95 HEAVY*
TENSION: *50% ULT TENSION- 1395#*

	INITIAL SAG TENSION (lbs.)				
	854	753	649	543	440
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	0
40	0	0	0	0	0
50	0	0	1	1	1
60	1	1	1	1	1
70	1	1	1	1	2
80	1	1	1	2	2
90	1	1	2	2	3
100	2	2	2	3	3
110	2	2	3	3	4
120	2	3	3	4	4
130	3	3	4	4	5
140	3	4	4	5	6
150	4	4	5	6	7
160	4	5	5	6	8
170	5	5	6	7	9
180	5	6	7	8	10
190	6	7	8	9	11
200	6	7	8	10	12
210	7	8	9	11	14
220	8	9	10	12	15
230	8	10	11	13	16
240	9	10	12	14	18
250	10	11	13	16	19
260	11	12	14	17	21
270	12	13	15	18	23
280	13	14	16	20	24
290	13	15	18	21	26
300	14	16	19	23	28
310	15	17	20	24	30
320	16	19	22	26	32
330	17	20	23	27	34
340	18	21	24	29	36
350	20	22	26	31	38
360	21	23	27	33	40
370	22	25	29	34	42
380	23	26	30	36	45
390	24	28	32	38	47
400	26	29	34	40	50
410	27	30	35	42	52
420	28	32	37	44	55
430	30	34	39	46	57
440	31	35	41	49	60
450	32	37	43	51	63

STRINGING SAG TABLE

CONDUCTOR: *SPARROW / #2 ACSR* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.091*

RULING SPAN: *300.0* TENSION: *50% ULT TENSION- 1395#*

	INITIAL SAG TENSION (lbs.)				
	670	571	475	390	320
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	0
40	0	0	0	1	1
50	1	1	1	1	1
60	1	1	1	1	2
70	1	1	1	2	2
80	1	2	2	2	3
90	2	2	2	3	3
100	2	2	3	4	4
110	2	3	3	4	5
120	3	3	4	5	6
130	3	4	5	6	7
140	4	5	6	7	8
150	5	5	6	8	10
160	5	6	7	9	11
170	6	7	8	10	12
180	7	8	9	11	14
190	7	9	10	13	15
200	8	10	11	14	17
210	9	11	13	15	19
220	10	12	14	17	21
230	11	13	15	19	23
240	12	14	17	20	25
250	13	15	18	22	27
260	14	16	19	24	29
270	15	17	21	26	31
280	16	19	23	27	33
290	17	20	24	29	36
300	18	22	26	32	38
310	20	23	28	34	41
320	21	24	29	36	44
330	22	26	31	38	46
340	24	28	33	40	49
350	25	29	35	43	52
360	26	31	37	45	55
370	28	33	39	48	58
380	29	35	42	51	62
390	31	36	44	53	65
400	33	38	46	56	68
410	34	40	48	59	72
420	36	42	51	62	75
430	38	44	53	65	79
440	39	46	56	68	83
450	41	48	58	71	86

STRINGING SAG TABLE

CONDUCTOR: *SPARROW / #2 ACSR* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.091*

RULING SPAN: *350.0* TENSION: *50% ULT TENSION- 1395#*

	INITIAL SAG TENSION (lbs.)				
	448	376	319	276	243
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	1
40	0	1	1	1	1
50	1	1	1	1	1
60	1	1	2	2	2
70	1	2	2	2	3
80	2	2	3	3	4
90	2	3	3	4	5
100	3	4	4	5	6
110	4	4	5	6	7
120	4	5	6	7	8
130	5	6	7	8	9
140	6	7	8	10	11
150	7	8	10	11	13
160	8	9	11	13	14
170	9	10	12	14	16
180	10	12	14	16	18
190	11	13	15	18	20
200	12	15	17	20	22
210	13	16	19	22	25
220	15	18	21	24	27
230	16	19	23	26	30
240	18	21	25	28	32
250	19	23	27	31	35
260	21	25	29	33	38
270	22	26	31	36	41
280	24	28	34	39	44
290	26	31	36	42	47
300	27	33	39	45	51
310	29	35	41	48	54
320	31	37	44	51	58
330	33	40	47	54	61
340	35	42	49	57	65
350	37	44	52	61	69
360	39	47	55	64	73
370	42	50	59	68	77
380	44	52	62	71	81
390	46	55	65	75	85
400	49	58	68	79	90
410	51	61	72	83	94
420	54	64	76	87	99
430	56	67	79	91	104
440	59	70	83	96	109
450	62	74	87	100	114

STRINGING SAG TABLE

CONDUCTOR: *SPARROW / #2 ACSR* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.091*

RULING SPAN: *400.0* TENSION: *50% ULT TENSION- 1395#*

	INITIAL SAG TENSION (lbs.)				
	306	272	246	225	208
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	1	1
40	1	1	1	1	1
50	1	1	1	2	2
60	2	2	2	2	2
70	2	2	3	3	3
80	3	3	4	4	4
90	4	4	4	5	5
100	4	5	6	6	7
110	5	6	7	7	8
120	6	7	8	9	9
130	8	8	9	10	11
140	9	10	11	12	13
150	10	11	12	14	15
160	11	13	14	16	17
170	13	15	16	18	19
180	14	16	18	20	21
190	16	18	20	22	24
200	18	20	22	24	26
210	20	22	24	27	29
220	22	24	27	29	32
230	24	27	29	32	35
240	26	29	32	35	38
250	28	31	35	38	41
260	30	34	38	41	44
270	33	37	40	44	48
280	35	39	44	48	51
290	38	42	47	51	55
300	40	45	50	55	59
310	43	48	53	58	63
320	46	51	57	62	67
330	49	55	60	66	71
340	52	58	64	70	76
350	55	61	68	74	80
360	58	65	72	79	85
370	61	69	76	83	90
380	64	72	80	88	95
390	68	76	84	92	100
400	71	80	89	97	105
410	75	84	93	102	110
420	79	89	98	107	116
430	83	93	103	112	121
440	86	97	107	118	127
450	90	102	112	123	133

STRINGING SAG TABLE

CONDUCTOR: *CANNA / 397.5 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.373*

RULING SPAN: *200.0* TENSION: *50% ULT TENSION- 3440#*

	INITIAL SAG TENSION (lbs.)				
	1822	1389	1039	800	649
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	1	1
40	0	1	1	1	1
50	1	1	1	2	2
60	1	1	2	3	3
70	2	2	3	3	4
80	2	3	3	4	6
90	2	3	4	6	7
100	3	4	5	7	9
110	4	5	7	8	10
120	4	6	8	10	12
130	5	7	9	12	15
140	6	8	11	14	17
150	7	9	12	16	19
160	8	10	14	18	22
170	9	12	16	20	25
180	10	13	17	23	28
190	11	15	19	25	31
200	12	16	22	28	34
210	14	18	24	31	38
220	15	19	26	34	42
230	16	21	28	37	46
240	18	23	31	40	50
250	19	25	34	44	54
260	21	27	36	47	58
270	22	29	39	51	63
280	24	32	42	55	68
290	26	34	45	59	73
300	28	36	48	63	78
310	30	39	52	67	83
320	31	41	55	72	88
330	33	44	59	76	94
340	36	47	62	81	100
350	38	49	66	86	106
360	40	52	70	91	112
370	42	55	74	96	118
380	44	58	78	101	125
390	47	61	82	106	131
400	49	64	86	112	138
410	52	68	91	118	145
420	54	71	95	123	152
430	57	74	100	129	160
440	59	78	104	136	167
450	62	82	109	142	175

STRINGING SAG TABLE

CONDUCTOR: *CANNA / 397.5 AA*
CONDUCTOR WT (lbs/ft): *.373*
RULING SPAN: *250.0*
LOADING: *G.O.95 HEAVY*
TENSION: *50% ULT TENSION- 3440#*

	INITIAL SAG TENSION (lbs.)				
	1923	1514	1182	944	784
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	1	1
40	0	1	1	1	1
50	1	1	1	1	2
60	1	1	2	2	3
70	1	2	2	3	3
80	2	2	3	4	5
90	2	3	4	5	6
100	3	4	5	6	7
110	4	4	6	7	9
120	4	5	7	9	10
130	5	6	8	10	12
140	6	7	9	12	14
150	7	8	11	13	16
160	7	9	12	15	18
170	8	11	14	17	21
180	9	12	15	19	23
190	11	13	17	21	26
200	12	15	19	24	29
210	13	16	21	26	31
220	14	18	23	29	35
230	15	20	25	31	38
240	17	21	27	34	41
250	18	23	30	37	45
260	20	25	32	40	48
270	21	27	35	43	52
280	23	29	37	46	56
290	24	31	40	50	60
300	26	33	43	53	64
310	28	36	45	57	69
320	30	38	48	61	73
330	32	40	52	65	78
340	34	43	55	69	83
350	36	45	58	73	87
360	38	48	61	77	93
370	40	51	65	81	98
380	42	53	68	86	103
390	44	56	72	90	109
400	47	59	76	95	114
410	49	62	80	100	120
420	51	65	84	105	126
430	54	68	88	110	132
440	56	72	92	115	138
450	59	75	96	120	145

STRINGING SAG TABLE

CONDUCTOR: *CANNA / 397.5 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.373*

RULING SPAN: *300.0* TENSION: *50% ULT TENSION- 3440#*

	INITIAL SAG TENSION (lbs.)				
	1946	1569	1265	1043	886
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	1
40	0	1	1	1	1
50	1	1	1	1	2
60	1	1	2	2	2
70	1	2	2	3	3
80	2	2	3	3	4
90	2	3	4	4	5
100	3	4	4	5	6
110	3	4	5	6	8
120	4	5	6	8	9
130	5	6	7	9	11
140	6	7	9	11	12
150	6	8	10	12	14
160	7	9	11	14	16
170	8	10	13	16	18
180	9	12	14	17	20
190	10	13	16	19	23
200	12	14	18	21	25
210	13	16	20	24	28
220	14	17	21	26	31
230	15	19	23	28	33
240	17	21	25	31	36
250	18	22	28	34	39
260	19	24	30	36	43
270	21	26	32	39	46
280	23	28	35	42	50
290	24	30	37	45	53
300	26	32	40	48	57
310	28	34	43	52	61
320	29	37	45	55	65
330	31	39	48	58	69
340	33	41	51	62	73
350	35	44	54	66	77
360	37	46	57	70	82
370	39	49	61	73	86
380	42	52	64	77	91
390	44	54	67	82	96
400	46	57	71	86	101
410	48	60	74	90	106
420	51	63	78	95	111
430	53	66	82	99	117
440	56	69	86	104	122
450	58	72	90	109	128

STRINGING SAG TABLE

CONDUCTOR: *CANNA / 397.5 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.373*

RULING SPAN: *350.0* TENSION: *50% ULT TENSION- 3440#*

	INITIAL SAG TENSION (lbs.)				
	1933	1590	1318	1115	967
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	1
40	0	1	1	1	1
50	1	1	1	1	1
60	1	1	2	2	2
70	1	2	2	2	3
80	2	2	3	3	4
90	2	3	3	4	5
100	3	4	4	5	6
110	4	4	5	6	7
120	4	5	6	7	8
130	5	6	7	8	10
140	6	7	8	10	11
150	7	8	10	11	13
160	7	9	11	13	15
170	8	10	12	15	17
180	9	11	14	16	19
190	10	13	15	18	21
200	12	14	17	20	23
210	13	16	19	22	26
220	14	17	21	24	28
230	15	19	22	27	31
240	17	20	24	29	33
250	18	22	27	31	36
260	20	24	29	34	39
270	21	26	31	37	42
280	23	28	33	39	45
290	24	30	36	42	49
300	26	32	38	45	52
310	28	34	41	48	56
320	30	36	43	51	59
330	32	38	46	55	63
340	33	41	49	58	67
350	35	43	52	61	71
360	38	46	55	65	75
370	40	48	58	69	79
380	42	51	61	72	84
390	44	54	65	76	88
400	46	56	68	80	93
410	49	59	71	84	97
420	51	62	75	89	102
430	54	65	79	93	107
440	56	68	82	97	112
450	59	71	86	102	117

STRINGING SAG TABLE

CONDUCTOR: *CANNA / 397.5 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.373*

RULING SPAN: *400.0* TENSION: *50% ULT TENSION- 3440#*

SPAN (FT)	INITIAL SAG TENSION (lbs.) 1690 / TEMPERATURE (°F) 20° SAG (INCHES)	1426 / 40° SAG (INCHES)	1225 / 60° SAG (INCHES)	1074 / 80° SAG (INCHES)	960 / 100° SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	0	0	0	0	1
40	1	1	1	1	1
50	1	1	1	1	1
60	1	1	2	2	2
70	2	2	2	3	3
80	2	3	3	3	4
90	3	3	4	4	5
100	3	4	5	5	6
110	4	5	6	6	7
120	5	6	7	8	8
130	6	7	8	9	10
140	6	8	9	10	11
150	7	9	10	12	13
160	8	10	12	13	15
170	10	11	13	15	17
180	11	13	15	17	19
190	12	14	16	19	21
200	13	16	18	21	23
210	15	17	20	23	26
220	16	19	22	25	28
230	18	21	24	28	31
240	19	23	26	30	34
250	21	25	29	33	36
260	22	27	31	35	39
270	24	29	33	38	42
280	26	31	36	41	46
290	28	33	38	44	49
300	30	35	41	47	52
310	32	38	44	50	56
320	34	40	47	53	60
330	36	43	50	57	63
340	38	45	53	60	67
350	41	48	56	64	71
360	43	51	59	68	76
370	45	54	63	71	80
380	48	57	66	75	84
390	50	60	69	79	89
400	53	63	73	83	93
410	56	66	77	88	98
420	58	69	81	92	103
430	61	73	84	96	108
440	64	76	88	101	113
450	67	79	93	106	118

STRINGING SAG TABLE

CONDUCTOR: *ARBUTUS / 795 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.746*

RULING SPAN: *200.0* TENSION: *25% ULT TENSION- 3475#*

	INITIAL SAG TENSION (lbs.)				
	1629	1317	1115	977	877
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	1
30	1	1	1	1	1
40	1	1	2	2	2
50	2	2	3	3	3
60	2	3	4	4	5
70	3	4	5	6	6
80	4	5	6	7	8
90	6	7	8	9	10
100	7	8	10	11	13
110	8	10	12	14	15
120	10	12	14	16	18
130	12	14	17	19	22
140	13	17	20	22	25
150	15	19	23	26	29
160	18	22	26	29	33
170	20	25	29	33	37
180	22	28	33	37	41
190	25	31	36	41	46
200	27	34	40	46	51
210	30	37	44	51	56
220	33	41	49	55	62
230	36	45	53	61	68
240	40	49	58	66	74
250	43	53	63	72	80
260	46	57	68	77	86
270	50	62	73	84	93
280	54	67	79	90	100
290	58	71	84	96	107
300	62	77	90	103	115
310	66	82	97	110	123
320	70	87	103	117	131
330	75	93	109	125	139
340	79	98	116	133	148
350	84	104	123	141	157
360	89	110	130	149	166
370	94	116	138	157	175
380	99	123	145	166	185
390	105	129	153	175	195
400	110	136	161	184	205
410	116	143	169	193	215
420	121	150	177	202	226
430	127	157	186	212	237
440	133	165	195	222	248
450	139	172	204	233	259

STRINGING SAG TABLE

CONDUCTOR: *ARBUTUS / 795 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.746*

RULING SPAN: *250.0* TENSION: *25% ULT TENSION- 3475#*

	INITIAL SAG TENSION (lbs.)				
	1518	1315	1168	1058	973
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	1	1	1	1	1
40	1	1	2	2	2
50	2	2	2	3	3
60	3	3	3	4	4
70	4	4	5	5	6
80	5	5	6	7	7
90	6	7	8	9	9
100	7	9	10	11	12
110	9	10	12	13	14
120	11	12	14	15	17
130	12	14	16	18	19
140	14	17	19	21	23
150	17	19	22	24	26
160	19	22	25	27	29
170	21	25	28	31	33
180	24	28	31	34	37
190	27	31	35	38	42
200	29	34	38	42	46
210	33	38	42	47	51
220	36	41	46	51	56
230	39	45	51	56	61
240	42	49	55	61	66
250	46	53	60	66	72
260	50	58	65	72	78
270	54	62	70	77	84
280	58	67	75	83	90
290	62	72	81	89	97
300	66	77	86	95	104
310	71	82	92	102	111
320	76	87	98	108	118
330	80	93	104	115	125
340	85	98	111	122	133
350	90	104	117	130	141
360	96	110	124	137	149
370	101	117	131	145	158
380	107	123	139	153	166
390	112	130	146	161	175
400	118	136	153	170	184
410	124	143	161	178	194
420	130	150	169	187	203
430	136	158	177	196	213
440	143	165	186	205	223
450	149	173	194	215	233

STRINGING SAG TABLE

CONDUCTOR: *ARBUTUS / 795 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.746*

RULING SPAN: *300.0* TENSION: *25% ULT TENSION- 3475#*

	INITIAL SAG TENSION (lbs.)				
	1454	1313	1203	1115	1043
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	1	1	1	1	1
40	1	1	1	2	2
50	2	2	2	3	3
60	3	3	3	4	4
70	4	4	5	5	5
80	5	5	6	6	7
90	6	7	8	8	9
100	8	9	9	10	11
110	9	10	11	12	13
120	11	12	13	14	15
130	13	14	16	17	18
140	15	17	18	20	21
150	17	19	21	23	24
160	20	22	24	26	27
170	22	25	27	29	31
180	25	28	30	33	35
190	28	31	34	36	39
200	31	34	37	40	43
210	34	38	41	44	47
220	37	41	45	49	52
230	41	45	49	53	57
240	44	49	54	58	62
250	48	53	58	63	67
260	52	58	63	68	73
270	56	62	68	73	78
280	60	67	73	79	84
290	65	72	78	84	90
300	69	77	84	90	97
310	74	82	89	97	103
320	79	87	95	103	110
330	84	93	101	109	117
340	89	99	108	116	124
350	94	104	114	123	132
360	100	111	121	130	139
370	105	117	127	138	147
380	111	123	134	145	155
390	117	130	142	153	163
400	123	137	149	161	172
410	129	143	157	169	181
420	136	151	164	177	190
430	142	158	172	186	199
440	149	165	180	195	208
450	156	173	189	204	218

STRINGING SAG TABLE

CONDUCTOR: *ARBUTUS / 795 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.746*

RULING SPAN: *350.0* TENSION: *25% ULT TENSION- 3475#*

	INITIAL SAG TENSION (lbs.)				
	1415	1311	1226	1155	1095
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	1	1	1	1	1
40	1	1	1	2	2
50	2	2	2	2	3
60	3	3	3	3	4
70	4	4	4	5	5
80	5	5	6	6	7
90	6	7	7	8	8
100	8	9	9	10	10
110	10	10	11	12	12
120	11	12	13	14	15
130	13	14	15	16	17
140	16	17	18	19	20
150	18	19	21	22	23
160	20	22	23	25	26
170	23	25	26	28	30
180	26	28	30	31	33
190	29	31	33	35	37
200	32	34	37	39	41
210	35	38	40	43	45
220	38	41	44	47	49
230	42	45	48	51	54
240	46	49	53	56	59
250	49	53	57	61	64
260	53	58	62	66	69
270	58	62	67	71	75
280	62	67	72	76	80
290	67	72	77	82	86
300	71	77	82	87	92
310	76	82	88	93	98
320	81	87	94	99	105
330	86	93	99	106	111
340	91	99	106	112	118
350	97	105	112	119	125
360	103	111	118	126	133
370	108	117	125	133	140
380	114	123	132	140	148
390	120	130	139	148	156
400	127	137	146	155	164
410	133	144	154	163	172
420	140	151	161	171	181
430	146	158	169	179	189
440	153	165	177	188	198
450	160	173	185	197	207

STRINGING SAG TABLE

CONDUCTOR: *ARBUTUS / 795 AA* LOADING: *G.O.95 HEAVY*

CONDUCTOR WT (lbs/ft): *.746*

RULING SPAN: *400.0* TENSION: *25% ULT TENSION- 3475#*

	INITIAL SAG TENSION (lbs.)				
	1389	1310	1243	1184	1133
	TEMPERATURE (°F)				
	20°	40°	60°	80°	100°
SPAN (FT)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)	SAG (INCHES)
0	0	0	0	0	0
10	0	0	0	0	0
20	0	0	0	0	0
30	1	1	1	1	1
40	1	1	1	2	2
50	2	2	2	2	2
60	3	3	3	3	4
70	4	4	4	5	5
80	5	5	6	6	6
90	7	7	7	8	8
100	8	9	9	9	10
110	10	10	11	11	12
120	12	12	13	14	14
130	14	14	15	16	17
140	16	17	18	19	19
150	18	19	20	21	22
160	21	22	23	24	25
170	23	25	26	27	29
180	26	28	29	31	32
190	29	31	33	34	36
200	32	34	36	38	40
210	36	38	40	42	44
220	39	41	44	46	48
230	43	45	48	50	52
240	46	49	52	54	57
250	50	53	56	59	62
260	54	58	61	64	67
270	59	62	66	69	72
280	63	67	71	74	77
290	68	72	76	80	83
300	73	77	81	85	89
310	77	82	87	91	95
320	83	88	92	97	101
330	88	93	98	103	108
340	93	99	104	109	114
350	99	105	110	116	121
360	104	111	117	123	128
370	110	117	123	130	135
380	116	123	130	137	143
390	123	130	137	144	150
400	129	137	144	151	158
410	136	144	152	159	166
420	142	151	159	167	174
430	149	158	167	175	183
440	156	166	175	183	192
450	163	173	183	192	200

STANDARD SAGGING PRACTICES

1.0 INDEX

2.0 PURPOSE

This guide is to present a standard procedure for the three most common methods of conductor sagging. Sagging by dynamometer, by the wave return method, and sagging by eye.

3.0 SAGGING BY DYNAMOMETER

Tension may be measured directly at the point of pull by the use of a dynamometer or similar device. But in most cases this method is unsuitable due to long span lengths, or heavy wire, as sheave friction causes tension and sag to vary from span to span. Moreover, the dynamometer is difficult to read, and keep in adjustment, so there is always that risk of putting undue stress on the conductor and structures involved. One thing to keep in mind about this method is that difficulties become more pronounced with larger conductors.

4.0 WAVE RETURN METHOD

Sag may be determined by the use of a stopwatch that will measure time or sag in feet and tenths of feet for a vibratory wave to make a certain number of reflected returns. The wave being originated by the use of a line over the conductor at one end of a selected control span.

The time of return is a direct function of conductor tension and when this has been determined, both tension and sag may be read from the proper curves. This method can be useful on short span construction with small to medium sized conductor, but can be no more than a rough check on long span construction or with the use of a large conductor.

NOTE:
This method is of no use in a dead end span where the conductor has been attached to the insulators prior to check, due to the dampening effect of the insulators.

5.0 SAGGING BY TARGET

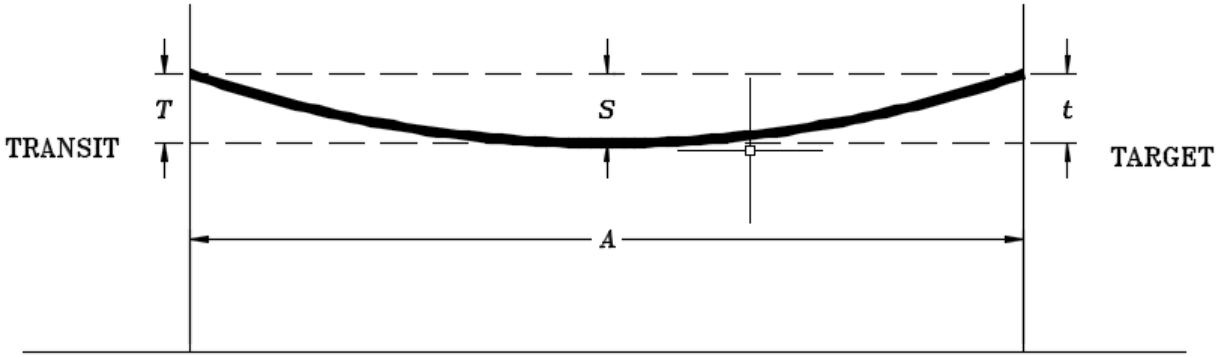
This is the most desired method of sagging because it is the most direct and also the fastest. The three most common methods of sagging by eye are the direct target method, the computed target method, and the vertical angle method.

5.1 The Direct Target Method:

This is the least involved of the three methods listed and institutes a target set at a distance equal to that of the desired sag measured down from the conductor support level on one structure, and a structure mounted transit set at the same distance down from the conductor support level on the opposing structure. With the use of a bracket mounted transit, in many cases structure vibration hampers sighting which makes it difficult to sag accurately.

This method may only be used if there is very little or no elevation difference between structures in a chosen control span, and the span length is close to that of the ruling span. (See drawing below)

5.1A Direct Target Method Reference Drawing



A = Span Length
S = Conductor Sag
T = Transit location measured down from the conductor attachment point at a distance equal to "S", or T = S
t = Target location measured down from the conductor attachment point at a distance equal to "S", or t = S

5.2 Computed Target Method: (Big "T", little "t")

With this method the transit may be tripod mounted and positioned at the base of the structure at a desirable "T", and target "t" computed for the opposing structure. With this method also, the more level spans closest to the ruling span length should be utilized (See Sections 6.0 & 6.1). Every method has its limitations and with this method if the distance between the transit and conductor support varies greatly from the actual sag, the line of sight will become tangent to the conductor at a point too far from the maximum allowable point or ordinate of the catenary. This situation will compound itself with greater elevation differences between structures in a chosen control span. A rule of thumb for determining a spans usability for sagging is 3/4 S<T<4/3 S, or three-fourths of S less than T but T less than four-thirds of S.

Examples:

1. **If:** S = 20' T = 50'
   Then: 3/4 (20') < 50' < 4/3 (50')
   15' < 50' < 26.7'

2. **If:** S = 40' T = 50'
   Then: 3/4 (40') < 50' < 4/3 (40')
   30' < 50' < 53.33'

3. **If:** S = 40' T = 60'
   Then: 3/4 (40') < 60' < 4/3 (40')
   30' < 60' < 53.33'

We know now that example #1 would not work out as a control span without adjusting "T" to a smaller value. Example #2 could be used with the values as they are, and example #3 may be considered as a possibility if the span length is long enough. The simplest answer for using examples #1 or #3 for sagging is to adjust the value of "T" until the limitations are met, this would position the transit up the structure in this case.

A more involved method of determining the usability of a span for sagging is by computing a control factor and checking it against a standard chart (See Sections 7.0 & 7.1). If the control factor exceeds the minimum allowed for on the chart, this would be considered a usable control span, if it does not, and a better value for "T" cannot be obtained, it is best to choose another control span to insure a proper sag.

5.3 Vertical Angle Method:

This method would be used in cases where the actual sag of the conductor falls below the base of the opposing structure, and targets "t" cannot be used for sighting. With this method of determining sag, the transit shall be set at a convenient distance "T" below the conductor point of support on the

low structure. Then the vertical angle of sight must be computed, and the transit set at this angle above or below the horizontal (See Sections 6.0 & 6.2) Angle m can be computed by simple geometry if "t" has already been determined.

Formula for m:

$m = \tan^{-1} (T + B - t)/A$

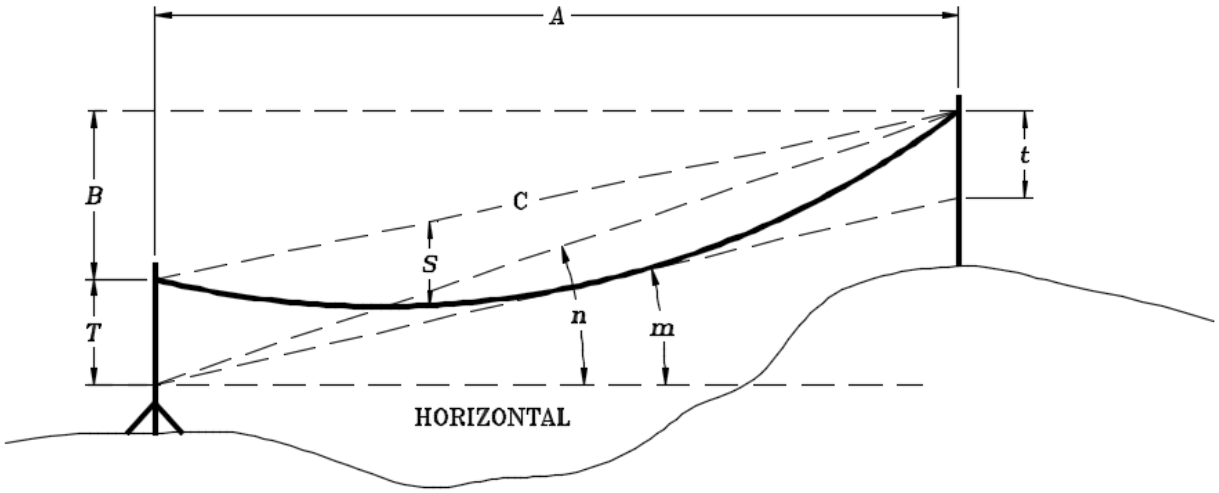
From Section 6.2: $\tan m = (T + B - t)/A$

This method as in the computed target method should also meet the requirements of the limiting control factor. So "t" should be computed before determining angle “m” and checked thru the control factor formula to make sure that the values fall within the limitations of the control factor standard chart. This will insure usability as a control span for sagging. If these requirements are not met, "T", if possible, may be adjusted so as to meet the limitations of the control factor. If this cannot be done, it is best to choose another control span. Remember, special attention should be paid to the value of "B", this value should not be scaled from a profile, it can be determined by simple triangulation with an accurate transit. This method is explained on the sheet containing the formulas for determining sag, under the vertical angle method. $+B = [A (\tan n)]-T$ (See Section 6.0). It is important to pay close attention to the algebraic signs (+ or -) of angle "n" and angle "m". Also checking the tangent of angle "m" may be accomplished by the use of this formula:

$$\tan m = ([A (\tan n)] - t)/A$$

This is one of the more involved methods of sagging conductor, and in most cases would be used in a situation where the party controlling the conductor sagging feels that there is no other alternative but to sag in a span of this nature.

6.0 COMPUTED TARGET & VERTICAL ANGLE REFERENCE DRAWING



S = Sag
A = Span Length
B = Difference in Elevation
C = Equivalent Span Length
T = Distance From Top of Transit to Point of Conductor Support at Structure Selected to Sag w/Transit
t = Determined Targets
m = Angle of Sight
n = Angle Used in computing Elevation Differences

6.1 Computed Target Method (Big "T" Little "t")

$t = (2\sqrt{S} - \sqrt{T})^2$

2 times the square root of a given sag minus the square root of "T" or the transit height measured down from the conductor support, this quantity squared equaling "t" or target distance measured down from the conductor support on the structure sighted towards.

6.2 Vertical Angle Method

Tangent of angle "m" = $(T \pm B - t)/A$

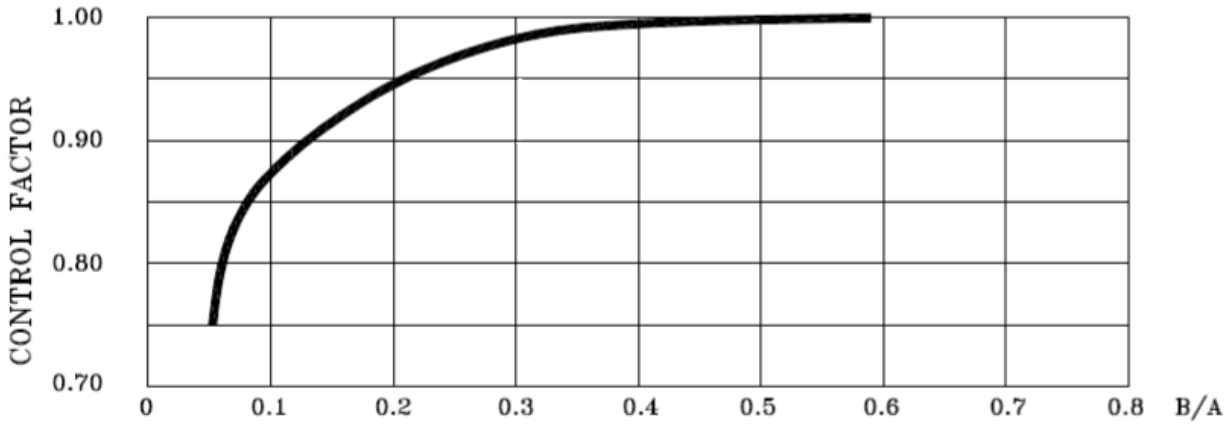
tan "m" converted to degrees = The setting for the vertical angle from horizontal on the transit.

± B = A x tangent of angle n - T, or ± B = A tan (n) – T

Difference in Elevation:

To obtain the difference in elevation "± B" with a transit, measure down from conductor support to top of transit "T". Turn vertical angle to point of conductor support on structure selected to sight to (angle n). Multiply the tangent of angle "n" by span length "A". If the result is greater than "T", the difference |A tan (n) - T| is a "+B". If the result is less than "T", the difference |A tan (n) - T| is a "-B".

7.0 STANDARD CONTROL FACTOR CHART



7.1 Computing Control Factor

Formula:

$CF = 1 - [(T-t)/4S]^2$ and $X = B/A$

CF= Control Factor
T= Big "T"
t = Little "t"
S = Sag
B= Difference of Support Elevation
A= Horizontal Span Length
X= Horizontal Axis of Graph

Example:

If: T = 60' S = 40' t = 24.03' B = 40' A = 1600'

Then:

$CF = 1 - \left(\frac{T - t}{4S}\right)^2$ and $X = B/A,$

$CF = 1 - \left(\frac{60 - 24.03}{4(40)}\right)^2$ $X = \frac{40.0}{1600}$

$CF = 1 - \left(\frac{35.97}{160}\right)^2$ $X = 0.025$

$CF = 1 - 0.05$

$CF = \underline{0.95}$

Results: This span exceeds the minimum requirements of the control factor chart, so it proves usability.

8.0 GENERAL INFORMATION

8.1 When figuring the actual value of "S" (sag) the controlling factors are: temperature, the span length, and sag correction (+ or -) if off-sets are being applied. Another consideration to keep in mind is the elevation difference and the application of the equivalent span lengths.

8.2 When using the sight by eye methods, a minimum of two sighting points must be calculated for each control span to allow for temperature change during the sag.

8.3 In determining control spans in a sag section, a minimum of two control spans must be utilized, and if a section warrants it, a control span placed at one mile intervals. Also, sag should be checked on either side of a break over, and one span either side of a sharp angle.

8.4 When sagging into a prior sag section, a rough check for sag would be to watch the insulator string at the clipped structure for plumb. After the completion of sag, these insulators should end up in the plumb position with the exception of the application of off-sets. The bell snubs must be utilized to hold this string of insulators plumb until the off-set section is plumb marked and clipped, then the bell snubs may be removed and the insulators on the clipped structure should hang plumb if the off-sets have been properly applied.

ATTACHMENT 8

Google Maps View of East and West Pole Locations

Imagery ©2025 Airbus, Maxar Technologies, Map data ©2025 Google 50 ft

CA-08-0211

ATTACHMENT 9

Commission's Safety and Enforcement Division's 2012 Audit of Liberty Utilities

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

August 24, 2012

Casey Kelley
General Foreman
Liberty Utilities
P.O. Box 107
Tahoe Vista, CA 96148

EA2012-013

SUBJECT: Audit of Liberty Utilities

Dear Mr. Kelley:

On behalf of the Electric Safety and Reliability Branch of the California Public Utilities Commission, Paul Penney and Ryan Yamamoto of my staff conducted an audit of Liberty Utilities (LU) from June 4, 2012 to June 7, 2012. The audit included a review of LU's maintenance records and inspections of LU's facilities.

During the audit, my staff identified violations of one or more General Orders. A copy of the audit summary itemizing the violations is enclosed. Please advise me no later than September 28, 2012, by electronic or hard copy, of all corrective measures taken by LU to remedy and prevent such violations.

If you have any questions concerning this audit you can contact, Ryan Yamamoto at (415) 703-2192 or ryan.yamamoto@cpuc.ca.gov.

Sincerely,

Raffy Stepanian, P.E.
Program Manager
Electric Safety and Reliability Branch
Consumer Protection and Safety Division
California Public Utilities Commission

Enclosures: CPUC Audit Summary

CC: Raymond Fugere, Program and Project Supervisor, CPUC
Alok Kumar, Senior Utilities Engineer (Supervisor), CPUC
Paul Penney, Utilities Engineer, CPUC
Ryan Yamamoto, Utilities Engineer, CPUC

Audit Summary

GO 165, Section III-B – Standards for Inspections, states:

> *"Each utility subject to this General Order shall conduct inspections of its distribution facilities, as necessary, to ensure reliable, high-quality, and safe operation, but in no case may the period between inspections (measured in years) exceed the time specified in Table 1."*

LU did not have sufficient records to demonstrate compliance with the inspection requirements of GO 165.

GO 165, Section III-C – Record Keeping states in part:

> *"The utility shall maintain records for (1) at least ten (10) years of patrol and detailed inspection activities, and (2) the life of the pole for intrusive inspection activities. Such records shall be made available to parties or pursuant to Commission rules upon 30 days notice. Commission staff shall be permitted to inspect such records consistent with Public Utilities Code Section 314 (a).*

LU does not have a written inspection program that requires recording keeping as specified in GO 165.

GO 165, Section III-C – Record Keeping states in part:

> *"For all inspections records shall specify the circuit, area, facility or equipment inspected, the inspector, the date of the inspection, and any problems (or items requiring corrective action) identified during each inspection, as well as the scheduled date of corrective action."*

LU did not document all violations of General Orders 95 and 128 during its inspections. Additionally, all violations that were discovered by the utility were not scheduled for corrective action.

GO 165, Section III-D, - Reporting, states in part:

> *"By July 1st each each utility subject to this General Order shall submit an annual report for the previous year under penalty of perjury."*

LU has not submitted any annual reports to the Commission. Annual reports must be submitted to the Commission by July 1st.

GO 95, Rule 18-A1a, - Resolution of Safety Hazards and GO 95 Nonconformances, states in part:

> *"Each company (including utilities and CIPs) is responsible for taking appropriate corrective action to remedy Safety Hazards and GO 95 nonconformances posed by its facilities."*

LU did not document, schedule for correction and correct all Safety Hazards received from other companies.

GO 95, Rule 18-B, - Notification of Safety Hazards, states in part:

> *"If a company, while performing inspections of its facilities, discovers a safety hazard(s) on or near a communications facility or electric facility involving another company, the inspecting company shall notify the other company and/or facility owner of such safety hazard(s) no later than 10 business days after the discovery. To the extent the inspecting company cannot determine the facility owner/operator, it shall contact the pole owner(s), who shall be responsible for promptly notifying the company owning/operating the facility with the safety hazard(s), normally not to exceed five business days after being notified of the safety hazard. The notification shall be documented and such documentation must be preserved by all parties for at least ten years."*

LU does not notify other companies of safety hazards as required by GO 95.

GO 95, Rule 44.2, Additional Construction, States:

> *"Any entity planning the addition of facilities that materially increase vertical, transverse or longitudinal loading on a structure shall perform a loading calculation to ensure that the addition of the facilities will not reduce the safety factors below the values specified by Rule 44.3. Such entity shall maintain these pole loading calculations for ten years and shall provide such information to authorized joint use pole occupants and the Commission upon request."*

LU's pole load calculations did not contain accurate information; specifically, the data used in the calculation did not accurately reflect the facilities in the field. Pole loading calculations need to use accurate information.

GO 128, Rule 17.8, Identification of Manholes, Handholes, Subsurface and Self-contained Surface-mounted Equipment Enclosures, states:

> **"***Manholes, handholes , subsurface and self-contained surface-mounted equipment enclosures shall be marked as to ownership to facilitate identification by persons authorized to work therein and by other persons performing work in their vicinity."*

LU needs to update the ownership identification signs on its padmounted equipment. Currently, LU staff is not always documenting this violation when it inspects its facilities.

Field Violations

1.	Location:	7276 Highway 28, Tahoe Vista (Equipment # 244289)
	Previous LU Visit Details:	03/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	Ground Molding Missing GO 95, Rule 54.6-B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)"* At this location, LU's pole had a ground wire that was exposed. This violation was not documented when LU last visited this location.	

2.	Location:	480 North Ridge Road, Carnelian Bay (Equipment # 96794)
	Previous LU Visit Details:	02/23/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	Secondary Crossarm Contact Above Insulator On Anchor Guy GO 95, Rule 56.7-B, states in part: *"In order to prevent trees, buildings, messengers, metal–sheathed cables or other similar objects from grounding portions of guys above guy insulators, it is suggested that anchor guys be sectionalized, where practicable, near the highest level permitted by this Rule."* At this location, LU's anchor guy had secondary crossarm contact above the guy insulator. This violation was not documented when LU last visited this location.	

3.	**Location:**	620 North Ridge Road, Carnelian Bay (Equipment # 90576)
	Previous LU Visit Details:	03/23/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Secondary Crossarm Contact Above Insulator On Anchor Guy</u> GO 95, Rule 56.7-B, states in part: *"In order to prevent trees, buildings, messengers, metal–sheathed cables or other similar objects from grounding portions of guys above guy insulators, it is suggested that anchor guys be sectionalized, where practicable, near the highest level permitted by this Rule."* At this location, LU's anchor guy had secondary crossarm contact above the guy insulator. This violation was not documented when LU last visited this location.	

4.	**Location:**	620 North Ridge Road, Carnelian Bay (Equipment # 90575)
	Previous LU Visit Details:	02/23/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Anchor Guy Less Then Three (3) Inches From Secondary Conductor</u> GO 95, Rule 38, Table 2 states in part: *"The minimum vertical, horizontal or radial clearances of wires from other wires shall not be less than the values given in Table 2 and are based on a temperature of 60° F. and no wind. Conductors may be deadended at the crossarm or have reduced clearances at points of transposition, and shall not be held in violation of Table 2, Cases 8–15, inclusive."* At this location, LU's anchor guy less then three (3) inches from the secondary conductor. This violation was not documented when LU last visited this location.	

5.	**Location:**	Woodchuck Drive & North Ridge Road, Carnelian Bay (Equipment # 90568)
	Previous LU Visit Details:	02/23/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Overhead Conductor Less Than 18 Inches From Tree</u> GO95, Rule 35, states in part: *"Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances, the minimum clearances set forth in Table 1, Cases 13 and 14, measured between line conductors and vegetation under normal conditions shall be maintained. (Also see Appendix E for tree trimming guidelines.) These requirements apply to all overhead electrical supply and communication facilities that are covered by this General Order, including facilities on lands owned and maintained by California state and local agencies."* At this location, LU's overhead conductor was less than 18 inches from a tree. This violation was not documented when LU last visited this location.	

6.	**Location:**	457 Terrace Drive, Carnelian Bay (Equipment # 45303)
	Previous LU Visit Details:	03/23/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Ground Wire Exposed

GO 95, Rule 54.6-B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's pole had a ground wire that was exposed. This violation was not documented when LU last visited this location.

Missing High Voltage Sign

GO 95, Rule 51.6-A, states in part:

> *"Poles which support line conductors of more than 750 volts shall be marked with high voltage signs…."*

At this location, LU's pole was missing a high voltage sign. This violation was not documented when LU last visited this location.

7.	**Location:**	5850 Ophir Street, Carnelian Bay (Equipment # 39579)
	Previous LU Visit Details:	03/20/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Slack Anchor Guy

GO 95, Rule 56.2 states in part:

> *"Guys shall be attached to structures, as nearly as practicable, at the center of load. They shall be maintained taut and of such strength as to meet the safety factors of Rule 44."*

At this location, LU's anchor guy was slack. This violation was not documented when LU last visited this location.

Ground Wire Exposed

GO 95, Rule 54.6-B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's pole had a ground wire that was exposed. This violation was not documented when LU last visited this location.

8.	**Location:**	Mountain Circle & Wildwood Road, Tahoe Vista (Equipment # 81583)
	Previous LU Visit Details:	01/20/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Wire Exposed</u> GO 95, Rule 54.6-B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's pole had a ground wire that was exposed. This violation was not documented when LU last visited this location.	

9.	**Location:**	5984 Dodowah Road (Equipment # 85741)
	Previous LU Visit Details:	01/13/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Slack Anchor Guy

GO 95, Rule 56.2 states in part:

> *"Guys shall be attached to structures, as nearly as practicable, at the center of load. They shall be maintained taut and of such strength as to meet the safety factors of Rule 44."*

At this location, LU's anchor guy was slack. This violation was not documented when LU last visited this location.

Missing High Voltage Sign

GO 95, Rule 51.6-A, states in part:

> *"Poles which support line conductors of more than 750 volts shall be marked with high voltage signs…."*

At this location, LU's pole was missing a high voltage sign. This violation was not documented when LU last visited this location.

10.	**Location:**	6548 North Lake Boulevard, Tahoe Vista (Equipment # 81463)
	Previous LU Visit Details:	01/10/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Wire Exposed</u> GO 95, Rule 54.6-B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's pole had ground wire that was exposed. This violation was not documented when LU last visited this location.	

11.	Location:	8486 Golden Avenue, Kings Beach (Equipment # 81447)
	Previous LU Visit Details:	05/18/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Ground Wire Exposed

GO 95, Rule 54.6, B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's pole had a ground wire that was exposed. This violation was not documented when LU last visited this location.

Foreign Attachment

GO 95, Rule 34, states in part:

> *"Nothing in these rules shall be construed as permitting the unauthorized attachment, to supply, street light or communication poles or structures, of antennas, signs, posters, banners, decorations, wires, lighting fixtures, guys, ropes and any other such equipment foreign to the purposes of overhead electric line construction.*
>
> *Nothing herein contained shall be construed as requiring utilities to grant permission for such use of their overhead facilities; or permitting any use of joint poles or facilities for such permanent or temporary construction without the consent of all parties having any ownership whatever in the poles or structures to which attachments may be made; or granting authority for the use of any poles, structures or facilities without the owner's or owners' consent."*

At this location, LU's pole had a foreign attachment. This violation was not documented when LU last visited this location.

12.	**Location:**	8434 Loch Levon Avenue, Kings Beach (Equipment # 68531)
	Previous LU Visit Details:	02/23/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Rod And Ground Wire Exposed</u> GO 95, Rule 54.6, B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's ground wire and ground rod was exposed. This violation was not documented when LU last visited this location.	

13.	Location:	Golden Avenue & Deer Street, Kings Beach (Equipment # 81441)
	Previous LU Visit Details:	03/22/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Ground Wire Exposed

GO 95, Rule 54.6, B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's ground wire was exposed. This violation was not documented when LU last visited this location.

Cable Attached To LU' Ground

GO 95, Rule 33.3, B, states in part:

> *"Ground connections for equipment of any one of the types listed in Rule 33.3–A shall not be interconnected with ground connections for equipment of any other type listed therein…:*

At this location, LU's ground connection has a cable ground wire attached. This violation was not documented when LU last visited this location.

14.	**Location:**	8779 Brockway Vista Avenue, Kings Beach (Equipment # 208483)
	Previous LU Visit Details:	03/22/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Anchor Guy Touching Communication Cable</u> GO 95, Rule 38, Table 2 states in part: *"The minimum vertical, horizontal or radial clearances of wires from other wires shall not be less than the values given in Table 2 and are based on a temperature of 60° F. and no wind. Conductors may be deadended at the crossarm or have reduced clearances at points of transposition, and shall not be held in violation of Table 2, Cases 8–15, inclusive."* At this location, LU's anchor guy was in contact with a communication cable. This violation was not documented when LU last visited this location.	

15.	**Location:**	8732 Rainbow Avenue, Kings Beach (Equipment # 92275)
	Previous LU Visit Details:	03/20/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Ground Wire Exposed

GO 95, Rule 54.6, B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's ground wire was exposed. This violation was not documented when LU last visited this location.

Anchor Guy Touching Communication Cable

GO 95, Rule 38, Table 2 states in part:

> *"The minimum vertical, horizontal or radial clearances of wires from other wires shall not be less than the values given in Table 2 and are based on a temperature of 60° F. and no wind. Conductors may be deadended at the crossarm or have reduced clearances at points of transposition, and shall not be held in violation of Table 2, Cases 8–15, inclusive.*
> *The clearances in Table 2 shall in no case be reduced more than 10 percent because of temperature and loading as specified in Rule 43 or because of a difference in size or design of the supporting pins, hardware or insulators. All clearances of less than 5 inches shall be applied between surfaces, and clearances of 5 inches or more shall be applied to the center lines of such items."*

At this location, LU's anchor guy was in contact with a communication cable. This violation was not documented when LU last visited this location.

16.	**Location:**	8681 Rainbow Avenue, Kings Beach (Equipment # 81456)
	Previous LU Visit Details:	02/08/11
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Wire Exposed</u> GO 95, Rule 54.6, B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's ground wire was exposed. This violation was not documented when LU last visited this location.	

17.	**Location:**	970 Snow Show Road, Tahoe City (Equipment # 109225)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Tree Contact and Secondary Crossarm Contact Above Insulator On Anchor Guy</u> GO 95, Rule 56.7-B, Location of Sectionalizing Insulators states in part: *"In order to prevent trees, buildings, messengers, metal–sheathed cables or other similar objects from grounding portions of guys above guy insulators, it is suggested that anchor guys be sectionalized, where practicable, near the highest level permitted by this Rule."* At this location, LU's anchor guy had tree contact and secondary crossarm contact above the guy insulator. This violation was not documented when LU last visited this location.	

18.	**Location:**	970 Sky Way, Tahoe City (Equipment # 201316)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Anchor Guy Touching Communication Cable</u> GO 95, Rule 38, Table 2 states in part: *"The minimum vertical, horizontal or radial clearances of wires from other wires shall not be less than the values given in Table 2 and are based on a temperature of 60° F. and no wind. Conductors may be deadended at the crossarm or have reduced clearances at points of transposition, and shall not be held in violation of Table 2, Cases 8–15, inclusive.."* At this location, LU's anchor guy was in contact with a communication cable. This violation was not documented when LU last visited this location.	

19.	**Location:**	125 Talmont Circle, Tahoe City (Equipment # 155257)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Ground Rod And Ground Wire Exposed

GO 95, Rule 54.6-B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's ground wire and ground rod was exposed. This violation was not documented when LU last visited this location.

Missing High Voltage Sign

GO 95, Rule 51.6-A, states in part:

> *"Poles which support line conductors of more than 750 volts shall be marked with high voltage signs…."*

At this location, LU's pole had a damaged a high voltage sign. This violation was not documented when LU last visited this location.

20.	**Location:**	445 John Cain Road, Tahoe City (Equipment # 139525)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Wire Exposed</u> GO 95, Rule 54.6-B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's ground wire was exposed. This violation was not documented when LU last visited this location.	

21.	**Location:**	1975 Silver Tip Drive, Tahoe City (Equipment # 131178)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	

Tree Contact Above Insulator On Anchor Guy

GO 95, Rule 56.7-B, Location of Sectionalizing Insulators states in part:

> *"In order to prevent trees, buildings, messengers, metal–sheathed cables or other similar objects from grounding portions of guys above guy insulators, it is suggested that anchor guys be sectionalized, where practicable, near the highest level permitted by this Rule."*

At this location, LU's anchor guy had tree contact above the guy insulator. This violation was not documented when LU last visited this location.

Ground Wire Exposed

GO 95, Rule 54.6-B, states in part:

> *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."*

At this location, LU's ground wire was exposed. This violation was not documented when LU last visited this location.

Missing High Voltage Sign

GO 95, Rule 51.6-A, states in part:

> *"Poles which support line conductors of more than 750 volts shall be marked with high voltage signs…."*

At this location, LU's pole had a damaged high voltage sign. This violation was not documented when LU last visited this location.

22.	**Location:**	2090 Woodleigh Road, Tahoe City (Equipment # 180628)
	Previous LU Visit Details:	02/07/12
	Date of CPUC Inspection:	06/06/12
	Explanation of Violation(s):	
	<u>Ground Rod And Ground Wire Exposed</u> GO 95, Rule 54.6-B, states in part: *"That portion of the ground wire attached on the face or back of wood crossarms or on the surface of wood poles and structures shall be covered by a suitable protective covering (see Rule 22.8)."* At this location, LU's ground wire and ground rod was exposed. This violation was not documented when LU last visited this location.	

ATTACHMENT 10

Liberty CalPeco's Response to DR CalAdvocates-LIB-A2506017-019

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 13, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-019
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-019
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 29, 2025
Due Date:	October 13, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in accompanying confidentiality declaration. Public disclosure is restricted.

In Liberty's testimony (Exhibit Liberty – 03 at 16), it states that:

> *GO 95 requires that utility poles meet specified "safety factors," i.e., design criteria to accommodate the structural load exerted by wind, ice, and the weight of attached facilities. The calculation of these safety factors is referred to as "pole loading." Liberty performs pole loading calculations through its industry-standard "O-Calc" software on all poles that are being replaced or have an increase in loading from proposed new attachments, including covered tension conductor upgrades, consistent with GO 95 and Liberty's "Wood Pole Loading Criteria" standard.*
>
> *The number, size, height (i.e. ground clearances) requirements, wind loading, and dead-ending of conductors supported by a pole were the primary factors Liberty used to assess pole strength requirements. Liberty designed and constructed poles to meet GO 95's heavy loading standard. Higher class poles were also required for unusually long spans, heavy conductor loads, or heavy equipment installation.*

Questions 1 – 10 pertain to the time period **between 2011 and the Mountain View Fire.**

REQUEST NO. 1:

a) Did Liberty have a formal pole loading program?
b) If so, please produce all documents, data, and information necessary to describe the program.
c) If not, please explain why not

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows:

Liberty performed pole loading calculations to verify appropriate loading of poles pursuant to GO 95 at the time of construction and on replaced poles or poles where attachments/new equipment was added, including as part of covered conductor installation. Liberty did not have a standalone pole loading program. Please see Section 7.0 of Liberty's *Overhead Distribution Design and Application Criteria (GEN02T)* (pole loading study to be performed with Liberty's approved pole loading software when facilities are designed prior to construction); *Wood Pole Loading Criteria (POL05T)* (general data and guidance to assist in determining minimum class poles to meet requirements; computer program loading assessments be performed by designers to identify appropriate pole sizes for Liberty facilities); *Wood Pole Coding, Class and General Pole Framing Data (POL03T)* (pole data required for use in estimating work orders; general guidance on class requirements). These construction standards are part of Liberty's *Overhead Electric Standards*, previously provided in response to CalAdvocates-LIB-A2506017-018, Question 3. Liberty engineers and contractors determined loading on poles with industry-standard "O-Calc" software, as described in *Liberty-03: Prudence of Operations*, Section IV.A.

Liberty also made its pole loading calculations available to telecommunications companies and joint use occupants for pole loading calculations prior to attaching to Liberty poles.

REQUEST NO. 2:

Provide a copy of Liberty's "Wood Pole Loading Criteria" standard.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows: Please see Liberty's response and attachments to Question 1 of this set of data requests.

REQUEST NO. 3:

a) Did Liberty have a pole loading manual, procedure, or standard (other than Liberty's "Wood Pole Loading Criteria" standard)?
b) If so, please provide a copy of the manual, procedure, or standard.
c) If not, please explain why not.

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: Please see Liberty's response and attachments to Question 1 of this set of data requests.

REQUEST NO. 4:

What was Liberty's methodology for selecting poles for a loading assessment?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: Please see Liberty's response and attachments to Question 1 of this set of data requests.

REQUEST NO. 5:

a) Did Liberty conduct any pole loading assessments on the Topaz 1261 circuit?
b) If the answer to subpart (a) is yes, please provide all pole loading calculations, studies, or reports completed on the Topaz 1261 circuit.
c) If the answer to subpart (a) is no, please explain why not.

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: Liberty performed pole loading calculations on the Topaz 1261 Circuit concurrent with design of the Topaz Line Rebuild Project as required by GO 95. Liberty also periodically performed pole loading calculations on the Topaz 1261 Circuit as necessary, such as for repairs after the November 2020 Mountain View Fire. Liberty's records indicate that a pole loading calculation was performed for the West Pole in June 2017 by a telecommunications provider. Please see attachments *CONFIDENTIAL-Pole 40288 Loading Calculations.pdf* and *CONFIDENTIAL-Pole 266731 Loading Calculations.pdf* for pole loading calculations for the Specific Facilities located by Liberty. Liberty is continuing to search for additional records of pole loading calculations for the Topaz 1261 Circuit from prior to November 17, 2020, and will supplement this response if additional records are identified.

REQUEST NO. 6:

GO 95 Rule 43 describes heavy loading and light loading conditions.

a) What loading conditions did Liberty apply to the pole in the Topaz 1261 circuit?
b) Did Liberty use alternate loading conditions other than the heavy or light loading conditions described in GO 95 Rule 43?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: Liberty applied GO 95's Heavy Loading standard to construction and repairs associated with Topaz 1261 Circuit, including the Topaz Line Rebuild project. GO 95's Heavy Loading standard is required by Liberty's *Overhead*

Electric Standards. Liberty is not aware of alternate loading conditions used for design and construction since acquisition of facilities from NV Energy in 2011.

REQUEST NO. 7:

a) Did Liberty have a practice of verifying the configuration of poles in the field prior to conducing pole loading calculations?
b) If the answer to subpart (a) is no, explain why not.
c) If the answer to subpart (a) is yes, describe Liberty's practices and procedures to verify the configuration of poles prior to conducting pole loading calculations.
d) If the answer to subpart (a) is yes, provide any manuals, procedures, or standards that describe Liberty's practices and procedures to verify the configuration of poles prior to conducting pole loading calculations.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and overbroad as framed, including its time frame and use of the phrase "verifying the configuration." Subject to and without waiving its objections, Liberty responds as follows: Liberty engineers and contractors that performed pole loading calculations to support repairs, upgrades, and construction of new facilities relied upon various practices to verify the configuration of poles in the field prior to conducting pole loading calculations on existing facilities. These practices included consulting available records, including data maintained in Liberty's GIS system, as well as field checking and documenting the configuration of poles in the field. Liberty is not aware of manuals, procedures, or standards that required verification of pole configurations prior to conducting loading calculations.

REQUEST NO. 8:

a) Did Liberty have an internal procedure, manual, or standard detailing the requirements for various load and safety factors for different classes of poles under varying loading conditions?
b) If the answer to subpart (a) is yes, please provide a copy of the procedure, manual or standard.
c) If the answer to subpart (a) is no, please explain why not.
d) What criteria did Liberty use to determine if a pole needed to be replaced?
e) Did Liberty's criteria differ from GO 95 requirements?
f) If the answer to subpart (e) is yes, explain the differences in detail.
g) Did Liberty sometimes reinforce or otherwise improve overloaded poles instead of replacing them?
h) If the answer to subpart (g) is yes, describe the remedy in detail.
i) If the answer to subpart (g) is yes, please provide copies of any procedure, manual, or standard that describes when Liberty would reinforce or otherwise improve overloaded poles instead of replacing them.

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed, including as to the term "overloaded." Subject to and without waiving its objections, Liberty responds as

follows:

a) – c) See documents referenced in Liberty's response to Question 1 of this set of data requests, including Liberty's *Wood Pole Loading Criteria (POL05T)* regarding minimum safety factors for wood poles.
d) See Liberty's response to Question 11, which also describes its general practices during the requested period.
e) – f) Liberty's criteria for pole replacement do not differ from GO 95.
g) – i) See Liberty's response to Question 1. In cases where attachments/new equipment are added to an existing pole, Liberty considered structural supports or other modifications to the existing pole to the extent available as an alternative to pole replacement, consistent with Liberty's *Overhead Electric Standards,* pole loading and engineering requirements, and GO 95. Section 8.0 and Section 9.0 of *General Wood Data* (*POL01T)* describes standards for reinforcement of poles with wood stubs and steel supports. See Liberty's response to Question 11.

REQUEST NO. 9:

a) How were the pole loading assessment results used to prioritize pole replacements?
b) What was Liberty's decision-making process for prioritizing replacements?
c) How did Liberty identify poles with a high risk of failure?
d) How quickly were poles that failed the pole loading assessment addressed or replaced?
e) How quickly were poles with a high risk of failing the pole loading assessment addressed or replaced?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed, including as to the phrase "pole loading assessment results." Subject to and without waiving its objections, Liberty responds as follows: See Liberty's response to Questions 1 and 11 of this set of data requests. Consistent with GO 95, Liberty prioritized replacing poles that posed an immediate safety and/or reliability risk with high probability for significant impact. Liberty also prioritized replacing poles associated with grid hardening projects through wildfire mitigation initiatives, such as the Topaz Line Rebuild. Other factors, such as location in a High Fire Threat District, age of pole, weight of attachments, quantity of customers serviced, and proximity to customers may have been considered in prioritizing poles for replacement.

REQUEST NO. 10:

What were the safety factors for the poles listed below?

a) West Pole.
b) East Pole.
c) Provide all available reports, records, or other documentation used to substantiate your responses to subparts (a) and (b).

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: A pole loading record located by

Liberty indicates that the West Pole had a calculated safety factor of 4.99 as of June 29, 2017. After being replaced following the Mountain View Fire, the new pole had a safety factor of 5.02. Liberty has not identified records of pole loading calculations for the East Pole dated prior to November 17, 2020. After being replaced following the Mountain View Fire, the new pole had a safety factor of 5.18. Please see attachments provided in response to Question 5 of this set of data requests.

REQUEST NO. 11:

This question refers to Liberty's current practices.

a) How does Liberty monitor and track the condition and integrity of its poles?
b) What data is collected during monitoring?
c) How frequently is this data reviewed and analyzed?
d) What is the title and department of the person responsible for this review?
e) Does Liberty deploy any interim measures to ensure pole safety until replacements are installed?
f) If the answer to subpart (e) is yes, what interim measures does Liberty take to ensure pole safety until replacements were installed?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Subject to and without waiving its objections, Liberty responds as follows: Liberty does not have a standalone pole loading program; see Liberty's response to Question 1. Liberty monitors the condition and integrity of its poles, and undertakes appropriate repairs or reinforcements, through its intrusive pole inspection program, see Section V.B of *Liberty-03: Prudence of Operations*, as well as through its other inspection programs (see generally Section V of *Liberty-03*). Poles may be identified for upgrade or replacement through Liberty's routine patrol inspections, detailed inspections, intrusive pole inspections, or based on other reports from field personnel. Liberty also replaces or upgrades existing poles or makes modifications as necessary for planned reconductoring or other design projects, such as projects related to wildfire mitigation or circuit performance, consistent with Liberty's *Overhead Electric Standards*, pole loading and engineering requirements, and GO 95. Liberty has previously produced inspection records, including from its intrusive pole inspections and other inspection findings related to pole conditions, in response to prior data requests from Cal Advocates (e.g., Question 4 of CalAdvocates-LIB-A2506017-001, Question 2 of CalAdvocates-LIB-A2506017-004, and Question 11 of CalAdvocates-LIB-A2506017-015). Liberty's inspection programs are overseen by a Senior Manager, Operations, with support from a Manager of Strategic Projects. In response to and based on pole conditions identified in the field, Liberty deploys interim measures and emergent repairs if determined to be necessary to support public safety.

ATTACHMENT 11

Liberty's Response to CalAdvocates-LIB-A2506017-019, attachment "CONFIDENTIAL-Pole 266731 Loading Calculations"

Confidential

ATTACHMENT 12

Priority Wire & Cable Inc., *Aluminum Conductor Steel Reinforced Specifications*, Accessed December 5, 2025

ACSR – Aluminum Conductor Steel Reinforced

APPLICATION:

ACSR – Aluminum Conductor Steel Reinforced is used as bare overhead transmission cable and as primary and secondary distribution cable. ACSR offers optimal strength for line design. Variable steel core stranding for desired strength to be achieved without sacrificing ampacity.

CONDUCTORS:

- Aluminum alloy 1350-H119 wires, concentrically stranded around a steel core available with Class A, B or C galvanizing; aluminum coated (AZ); or aluminum-clad steel core (AL). Additional corrosion protection is available through the application of grease to the core or infusion of the complete cable with grease. Also available with Non Specular surface finish.

STANDARDS:

- B-230 Aluminum wire, 1350-H19 for Electrical Purposes
- B-232 Aluminum Conductors, Concentric-Lay-Stranded, Coated Steel Reinforced (ACSR)
- B-341 Aluminum-Coated Steel Core Wire for Aluminum Conductors, Steel Reinforced (ACSR/AZ)
- B-498 Zinc-Coated Steel Core Wire for Aluminum Conductors, Steel Reinforced (ACSR)
- B-500 Metallic Coated Stranded Steel Core for Aluminum Conductors, Steel Reinforced (ACSR)
- RUS Accepted

Code Word	Size (AWG or kcmil)	Stranding (AL/STL)	Diameter(inch)				Weight (lbs/kft)			Content %		Rated Breaking Strength (lbs.)	Resistance** (Ohms/kft)		Ampacity* (amps)
			Individual Wire			Comp. Cable OD	AL	STL	Total	AL	STL		DC @ 20ºC	AC @ 75ºC	
			AL	STL	Steel Core										
Turkey	6	6/1	0.0661	0.0661	0.0664	0.198	24.5	11.6	36	67.90	32.10	1,190	0.6410	0.806	105
Swan	4	6/1	0.0834	0.0834	0.0834	0.250	39.0	18.4	57	67.90	32.10	1,860	0.4030	0.515	140
Swanate	4	7/1	0.0772	0.1029	0.1029	0.257	39.0	28.0	67	58.13	41.87	2,360	0.3990	0.519	140
Sparrow	2	6/1	0.1052	0.1052	0.1052	0.316	62.0	29.3	91	67.90	32.10	2,850	0.2540	0.332	184
Sparate	2	7/1	0.0974	0.1299	0.1299	0.325	62.0	44.7	107	58.13	41.87	3,640	0.2510	0.338	184
Robin	1	6/1	0.1181	0.1181	0.1181	0.354	78.2	36.9	115	67.90	32.10	3,550	0.2010	0.268	212
Raven	1/0	6/1	0.1327	0.1327	0.1327	0.398	98.7	46.6	145	67.90	32.10	4,380	0.1590	0.217	242
Quail	2/0	6/1	0.1489	0.1489	0.1489	0.447	124.3	58.7	183	67.90	32.10	5,300	0.1260	0.176	276
Pigeon	3/0	6/1	0.1672	0.1672	0.1672	0.502	156.7	74.0	231	67.90	32.10	6,620	0.1000	0.144	315
Penguin	4/0	6/1	0.1878	0.1878	0.1878	0.563	197.7	93.4	291	67.90	32.10	8,350	0.0795	0.119	357
Waxwing	266.8	18/1	0.1217	0.1217	0.1217	0.609	250.3	39.2	290	86.45	13.55	6,880	0.0643	0.079	449
Partridge	266.8	26/7	0.1013	0.0788	0.2364	0.642	251.7	115.5	367	68.53	31.47	11,130	0.0637	0.078	475
Ostrich	300.0	26/7	0.1074	0.0835	0.2505	0.680	282.9	129.8	413	68.53	31.47	12,700	0.0567	0.069	492
Merlin	336.4	18/1	0.1367	0.1367	0.1367	0.683	315.8	49.5	365	86.45	13.55	8,680	0.0510	0.063	519
Linnet	336.4	26/7	0.1137	0.0884	0.2652	0.720	317.1	145.4	463	68.53	31.47	14,100	0.0505	0.062	529
Oriole	336.4	30/7	0.1059	0.1059	0.3177	0.741	318.2	208.9	527	60.35	39.65	17,300	0.0502	0.061	535
Chickadee	397.5	18/1	0.1486	0.1486	0.1486	0.743	373.1	58.5	432	86.45	13.55	9,940	0.0432	0.053	576
Brant	397.5	24/7	0.1287	0.0858	0.2574	0.772	375.0	137.0	512	73.23	26.77	14,600	0.0430	0.053	584
Ibis	397.5	26/7	0.1236	0.0961	0.2882	0.783	374.7	171.9	547	68.53	31.47	16,300	0.0428	0.052	587
Lark	397.5	30/7	0.1151	0.1151	0.3453	0.806	375.8	246.8	623	60.35	39.65	20,300	0.0425	0.052	594

All values are nominal and subject to correction.
** Current ratings based on 75˚C conductor temperature, 25˚C ambient temperature, emissivity 0.5, 2ft/sec wind in sun.*
*** Resistance is calculated using ASTM standard increments of stranding, and metal conductivity of 61.2% IACS for EC (1350) and 8% IACS for steel.*
AC (60Hz) resistance includes current dependent hysteresis loss factor for 1 and 3 layer constructions.

1-800-945-5542
www.PriorityWire.com
PRIORITY WIRE & CABLE, INC.
CA-08-0256

ACSR – Aluminum Conductor Steel Reinforced

Code Word	Size (AWG or kcmil)	Stranding (AL/STL)	Diameter(inch)				Weight (lbs/kft)			Content %		Rated Breaking Strength (lbs.)	Resistance** (Ohms/kft)		Ampacity* (amps)
			Individual Wire			Comp. Cable OD	AL	STL	Total	AL	STL		DC @ 20ºC	AC @ 75ºC	
			AL	STL	Steel Core										
Pelican	477.0	18/1	0.1628	0.1628	0.1628	0.814	447.8	70.2	518	86.45	13.55	11,800	0.0360	0.044	646
Flicker	477.0	24/7	0.1410	0.0940	0.2820	0.846	450.1	164.4	615	73.23	26.77	17,200	0.0358	0.044	655
Hawk	477.0	26/7	0.1354	0.1053	0.3159	0.858	449.6	206.4	656	68.53	31.47	19,500	0.0356	0.044	659
Hen	477.0	30/7	0.1261	0.1261	0.3783	0.883	451.1	296.2	747	60.35	39.65	23,800	0.0354	0.043	666
Osprey	556.5	18/1	0.1758	0.1758	0.1758	0.879	522.2	81.8	604	86.45	13.55	13,700	0.0308	0.038	711
Parakeet	556.5	24/7	0.1523	0.1015	0.3045	0.914	525.1	191.7	717	73.23	26.77	19,800	0.0307	0.038	721
Dove	556.5	26/7	0.1463	0.1138	0.3414	0.927	525.0	241.0	766	68.53	31.47	22,600	0.0306	0.038	726
Eagle	556.5	30/7	0.1362	0.1362	0.4086	0.953	526.3	345.6	872	60.35	39.75	27,800	0.0303	0.037	734
Peacock	605.0	24/7	0.1588	0.1059	0.3177	0.953	570.9	208.7	780	73.23	26.77	21,600	0.0282	0.035	760
Squab	605.0	26/7	0.1525	0.1186	0.3558	0.966	570.4	261.8	832	68.53	31.47	24,300	0.0281	0.035	765
Wood Duck	605.0	30/7	0.1420	0.1420	0.4260	0.994	572.0	375.6	948	60.35	39.55	28,900	0.0279	0.034	774
Teal	605.0	30/19	0.1420	0.0852	0.4260	0.994	572.0	367.4	939	60.89	39.11	30,000	0.0278	0.034	773
KingBird	636.0	18/1	0.1880	0.1880	0.1880	0.940	597.2	93.6	691	86.45	13.55	15,700	0.0270	0.033	773
Swift	636.0	36/1	0.1329	0.1329	0.1329	0.930	596.9	46.8	644	92.80	7.20	13,800	0.0271	0.033	769
Rook	636.0	24/7	0.1628	0.1085	0.3255	0.977	600.0	219.1	819	73.23	26.77	22,600	0.0268	0.033	784
Grosbeak	636.0	26/7	0.1564	0.1216	0.3648	0.990	599.9	276.2	876	68.53	31.47	25,200	0.0267	0.033	789
Scoter	636.0	30/7	0.1456	0.1456	0.4368	1.019	601.4	394.9	996	60.35	39.65	30,400	0.0256	0.033	798
Egret	636.0	30/19	0.1456	0.0874	0.4370	1.019	601.4	386.6	988	60.89	39.11	31,500	0.0266	0.033	798
Flamingo	666.6	24/7	0.1667	0.1110	0.3330	1.000	629.1	229.7	859	73.23	26.77	23,700	0.0256	0.032	807
Gannet	666.6	26/7	0.1601	0.1245	0.3735	1.014	628.7	288.5	917	68.53	31.47	26,400	0.0255	0.031	812
Stilt	715.5	24/7	0.1727	0.1151	0.3453	1.036	675.2	246.5	922	73.23	26.77	25,500	0.0239	0.029	844
Starling	715.5	26/7	0.1659	0.1290	0.3870	1.051	675.0	309.7	985	68.53	31.47	28,400	0.0238	0.029	849
Redwing	715.5	30/19	0.1544	0.0926	0.4630	1.081	676.3	434.0	1,110	60.89	39.11	34,600	0.0236	0.029	859
Coot	795.0	36/1	0.1486	0.1486	0.1486	1.040	746.2	58.5	805	92.80	7.20	16,800	0.0217	0.027	894
Cuckoo	795.0	24/7	0.1820	0.1213	0.3640	1.092	749.9	273.8	1,024	72.23	26.77	27,900	0.0215	0.027	901
Drake	795.0	26/7	0.1749	0.1360	0.4080	1.108	750.3	344.2	1,094	68.53	31.47	31,500	0.0214	0.026	907
Tern	795.0	45/7	0.1329	0.0886	0.2660	1.063	749.8	146.1	896	83.69	16.31	22,100	0.0216	0.027	887
Condor	795.0	54/7	0.1213	0.1213	0.3639	1.092	749.5	273.6	1,023	73.25	26.75	28,200	0.0215	0.027	889
Mallard	795.0	30/19	0.1628	0.0977	0.4885	1.140	751.9	483.1	1,235	60.89	39.11	38,400	0.0213	0.026	918
Chutepoke	850.0	45/7	0.1375	0.0917	0.2751	1.100	804.5	159.6	964	83.40	16.60	23,192	0.0204	0.025	935
Les Boules	864.9	42/7	0.1435	0.0797	0.2391	1.102	813.4	121.1	935	87.04	12.96	22,480	0.0201	0.025	950
Ruddy	900.0	45/7	0.1414	0.0943	0.2829	1.131	848.7	165.5	1,014	83.69	16.31	24,400	0.0191	0.024	958
Canary	900.0	54/7	0.1291	0.1291	0.3873	1.162	849.0	309.9	1,159	73.25	26.75	31,900	0.0190	0.024	961
Rail	954.0	45/7	0.1456	0.0971	0.2913	1.165	899.9	175.5	1,075	83.69	16.31	25,900	0.0180	0.023	993
Cardinal	954.0	54/7	0.1329	0.1329	0.3987	1.196	900.7	328.4	1,228	73.25	26.75	33,800	0.0179	0.023	996

All values are nominal and subject to correction.
** Current ratings based on 75˚C conductor temperature, 25˚C ambient temperature, emissivity 0.5, 2ft/sec wind in sun.*
*** Resistance is calculated using ASTM standard increments of stranding, and metal conductivity of 61.2% IACS for EC (1350) and 8% IACS for steel. AC (60Hz) resistance includes current dependent hysteresis loss factor for 1 and 3 layer constructions.*

ACSR – Aluminum Conductor Steel Reinforced

Code Word	Size (AWG or kcmil)	Stranding (AL/STL)	Diameter(inch)				Weight (lbs/kft)			Content %		Rated Breaking Strength (lbs.)	Resistance** (Ohms/kft)		Ampacity* (amps)
			Individual Wire			Comp. Cable OD	AL	STL	Total	AL	STL		DC @ 20ºC	AC @ 75ºC	
			AL	STL	Steel Core										
Ortolan	1033.5	45/7	0.1515	0.1010	0.3030	1.212	974.3	189.8	1,164	83.69	16.31	27,700	0.0167	0.021	1,043
Curlew	1033.5	54/7	0.1383	0.1383	0.4149	1.245	974.3	355.6	1,330	73.25	26.75	36,600	0.0165	0.021	1,047
Beaumont	1113.0	42/7	0.1628	0.0904	0.2712	1.250	1046.5	155.5	1,202	87.06	12.94	28,300	0.0156	0.020	990
Bluejay	1113.0	45/7	0.1573	0.1049	0.3147	1.259	1050.0	204.8	1,255	83.69	16.31	29,800	0.0155	0.019	1,092
Finch	1113.0	54/19	0.1436	0.0862	0.4310	1.293	1056.0	376.0	1,432	73.75	26.25	39,100	0.0154	0.020	1,093
Bunting	1192.5	45/7	0.1628	0.1085	0.3255	1.302	1125.0	219.1	1,344	83.69	16.31	32,000	0.0144	0.018	1,139
Grackle	1192.5	54/19	0.1486	0.0892	0.4460	1.338	1130.0	402.7	1,533	73.75	26.25	41,900	0.0144	0.018	1,140
Bittern	1272.0	45/7	0.1681	0.1121	0.3363	1.345	1200.0	233.9	1,434	83.69	16.31	34,100	0.0135	0.017	1,184
Pheasant	1272.0	54/19	0.1535	0.0921	0.4605	1.382	1206.0	429.3	1,635	73.75	26.25	43,600	0.0135	0.017	1,187
Dipper	1351.5	45/7	0.1733	0.1155	0.3465	1.386	1275.0	248.3	1,523	83.69	16.31	36,200	0.0127	0.016	1,229
Martin	1351.5	54/19	0.1582	0.0949	0.4745	1.424	1281.0	455.8	1,737	72.75	26.25	46,300	0.0127	0.016	1,232
Bobolink	1431.0	45/7	0.1783	0.1189	0.3567	1.427	1350.0	263.1	1,613	83.69	16.31	38,300	0.0120	0.015	1,272
Plover	1431.0	54/19	0.1628	0.0977	0.4885	1.465	1357.0	483.1	1,840	73.75	26.25	49,100	0.0120	0.016	1,275
Nuthatch	1510.5	45/7	0.1832	0.1221	0.3663	1.465	1425.0	277.4	1,702	83.69	16.31	40,100	0.0114	0.015	1,313
Parrot	1510.5	54/19	0.1672	0.1003	0.5015	1.505	1431.0	509.2	1,940	73.75	26.25	51,700	0.0114	0.015	1,318
Lapwing	1590.0	45/7	0.1880	0.1253	0.3759	1.504	1500.0	292.2	1,792	83.69	16.31	42,200	0.0108	0.014	1,354
Falcon	1590.0	54/19	0.1716	0.1030	0.5150	1.545	1507.0	537.0	2,044	73.75	26.25	54,500	0.0108	0.014	1,359
Chukar	1780.0	84/19	0.1456	0.0874	0.4370	1.602	1688.0	386.6	2,075	81.30	18.70	51,000	0.0097	0.013	1,453
Bluebird	2156.0	84/19	0.1602	0.0961	0.4805	1.762	2044.0	467.4	2,511	81.30	18.70	60,300	0.0081	0.011	1,623
Kiwi	2167.0	72/7	0.1735	0.1157	0.3471	1.735	2055.0	248.9	2,304	89.20	10.80	49,800	0.0080	0.011	1,607
Thrasher	2312.0	76/19	0.1744	0.0814	0.4070	1.802	2191.0	335.4	2,527	86.73	13.27	56,700	0.0075	0.010	1,673
Joree	2515.0	76/19	0.1819	0.0849	0.4245	1.880	2384.0	364.8	2,749	86.73	13.27	61,700	0.0069	0.009	1,751
High Mechanical Strength															
Grouse	80.0	8/1	0.1000	0.1670	0.1670	0.367	75.1	73.9	149.0	50.56	49.44	5,200	0.2070	0.261	204
Petrel	101.8	12/7	0.0921	0.0921	0.2763	0.461	96.0	158.0	254.0	37.79	62.21	10,400	0.1580	0.239	237
Minorca	110.8	12/7	0.0961	0.0961	0.2883	0.481	103.9	172.1	276.0	37.79	62.21	11,300	0.1450	0.223	246
Leghorn	134.6	12/7	0.1059	0.1059	0.3177	0.530	127.0	209.0	336.0	37.79	62.21	13,600	0.1200	0.189	273
Guinea	159.0	12/7	0.1151	0.1151	0.3453	0.576	149.2	246.8	396.0	37.79	62.21	16,000	0.1010	0.165	297
Dotterel	176.9	12/7	0.1214	0.1214	0.3642	0.607	166.4	274.6	441.0	37.79	62.21	17,300	0.0911	0.151	312
Dorking	190.8	12/7	0.1261	0.1261	0.3783	0.631	179.7	296.3	476.0	37.79	62.21	18,700	0.0845	0.142	324
Brahma	203.2	16/19	0.1127	0.0977	0.4885	0.714	190.0	485.0	675.0	28.33	71.67	28,400	0.0764	0.135	341
Cochin	211.3	12/7	0.1327	0.1327	0.3981	0.664	198.8	328.2	527.0	37.79	62.21	30,700	0.0764	0.131	340

All values are nominal and subject to correction.
** Current ratings based on 75˚C conductor temperature, 25˚C ambient temperature, emissivity 0.5, 2ft/sec wind in sun.*
*** Resistance is calculated using ASTM standard increments of stranding, and metal conductivity of 61.2% IACS for EC (1350) and 8% IACS for steel. AC (60Hz) resistance includes current dependent hysteresis loss factor for 1 and 3 layer constructions.*

1-800-945-5542
www.PriorityWire.com

PRIORITY WIRE & CABLE, INC.

CA-08-0258
03-2021

ATTACHMENT 13

Liberty CalPeco's Response to DR CalAdvocates-LIB-A2506017-036

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

November 17, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-036
Requesting Party:	Public Advocates Office
Originator:	Tyler Holzschuh, Tyler.Holzschuh@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
	Cal Advocates Wildfire Discovery CalAdvocates.WildfireDiscovery@cpuc.ca.gov
Date Received:	November 3, 2025
Due Date:	November 17, 2025

This data request relates to Liberty Utilities' current pole loading calculation recordkeeping practices.

REQUEST NO. 1:

For each pair of latitude and longitude, please provide, for the nearest pole or tower, the most recent pole or tower loading calculation performed prior to October 28, 2025:

Latitude	Longitude
38.76564407	-119.7834473
38.88949966	-119.9783783
39.07063675	-120.1500778
39.78647995	-120.4284897
39.34766006	-120.1044006
38.99313736	-120.1080551
39.24095535	-120.02491
39.14328766	-120.1761475
39.22863388	-120.0127716
38.90582275	-119.9556885
38.94078064	-119.9777679
38.85646439	-120.015892
38.85896301	-120.0348434
38.94351578	-119.9668198
38.92408371	-120.0030365
38.85274887	-120.0098953
39.34192276	-120.1005707
38.58744812	-119.4686661
39.06858444	-120.1385574
39.0651741	-120.1353455

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question to the extent that coordinates 38.76564407, -119.7834473 are not in proximity to a specific pole and therefore Liberty is unable to provide a response with respect to these coordinates. For the other coordinates listed in this Question, Liberty has identified a pole in proximity to the specified locations. Subject to and without waiving its objections, Liberty responds as follows:

Two of the poles in proximity to the GPS coordinates listed in this Question were installed by Liberty after it acquired the utility from NV Energy in approximately 2011: Pole 293021 in proximity to GPS coordinates 38.85646439, -120.015892 and Pole 291332 in proximity to GPS coordinates 39.78647995, -120.4284897. See *Attachment to CalAdvocates-LIB-A2506017-036, Q1.zip* for pole loading calculations for these two poles. Liberty's records indicate that the pole in proximity to coordinates 39.34766006, -120.1044006 is owned by Truckee Donner Public Utility District. For the remaining poles in proximity to the listed GPS coordinates, Liberty's records indicate that these poles were installed before Liberty acquired the utility from NV Energy in approximately 2011. Liberty has not located pole loading calculations for these other poles given the passage of time. Liberty continues to search hard copy records and will supplement this response if additional responsive documents are located.