ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

May 1, 2018

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 18-035-17** – Rocky Mountain Power's Service Quality Review Report
Docket No. 08-035-55 – Service Quality Standards – June 2013 Service Quality Review Report
Docket No. 13-035-01 – Rocky Mountain Power's Service Quality Review Report
Docket No. 15-035-72 – Rocky Mountain Power's Service Quality Review Report

In compliance with the Commission's June 11, 2009 order in Docket No. 08-035-55 and December 20, 2016 order in Docket Nos. 13-035-01 and 15-035-72, and pursuant to the requirements of Rule R746-313, Rocky Mountain Power submits the Service Quality Review Report for the period January through December 2017.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
Jana.saba@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulations

Enclosures

CERTIFICATE OF SERVICE

Docket No. 18-035-17

I hereby certify that on May 1, 2018, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Cheryl Murray	cmurray@utah.gov
Michele Beck	mbeck@utah.gov
Division of Public Utilities	
Erika Tedder	etedder@utah.gov
Assistant Attorney General	
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Steven Snarr	stevensnarr@agutah.gov
Rocky Mountain Power	
Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com; utahdockets@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH
SERVICE QUALITY
REVIEW

January 1 – December 31, 2017
Report

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EXECUTIVE SUMMARY

Rocky Mountain Power has a number of Performance Standards and Customer Guarantee service quality measures and reports currently in place. These standards and measures are reflective of Rocky Mountain Power's performance (both customer service and network performance) in providing customers with high levels of service. The Company developed these standards and measures using industry standards for collecting and reporting performance data where they exist. In other cases, largely where the industry has no established standards, Rocky Mountain Power has developed metrics, reporting and targets. These existing standards and measures can be used over time, both historically and prospectively, to measure the quality of service delivered to our customers. In 2012 the Company and stakeholders collaboratively developed reliability reporting rules that were intended to replace the Service Standards Program. This report reflects those changes and captures the state rules. In 2016 the Company worked with the Division of Public Utilities to establish a method to recognize fundamental changes in the performance of the network allowing for updates to performance baselines. These changes are also incorporated into this document.

1 Service Standards Program Summary[1]

1.1 Rocky Mountain Power Customer Guarantees

Customer Guarantee 1: Restoring Supply After an Outage	The Company will restore supply after an outage within 24 hours of notification with certain exceptions as described in Rule 25.
Customer Guarantee 2: Appointments	The Company will keep mutually agreed upon appointments, which will be scheduled within a two-hour time window.
Customer Guarantee 3: Switching on Power	The Company will switch on power within 24 hours of the customer or applicant's request, provided no construction is required, all government inspections are met and communicated to the Company and required payments are made. Disconnection for nonpayment, subterfuge or theft/diversion of service is excluded.
Customer Guarantee 4: Estimates For New Supply	The Company will provide an estimate for new supply to the applicant or customer within 15 working days after the initial meeting and all necessary information is provided to the Company and any required payments are made.
Customer Guarantee 5: Respond To Billing Inquiries	The Company will respond to most billing inquiries at the time of the initial contact. For those that require further investigation, the Company will investigate and respond to the Customer within 10 working days.
Customer Guarantee 6: Resolving Meter Problems	The Company will investigate and respond to reported problems with a meter or conduct a meter test and report results to the customer within 10 working days.
Customer Guarantee 7: Notification of Planned Interruptions	The Company will provide the customer with at least two days' notice prior to turning off power for planned interruptions consistent will Rule 25 and relevant exemptions.

Note: See Rule 25 for a complete description of terms and conditions for the Customer Guarantee Program.

[1] In 2012, rules were codified in Utah Administrative Code R746-313. The Company, Commission and other stakeholders worked to develop mechanisms that comply with these rules and supersedes the Company's Service Standards Program.

1.2 Rocky Mountain Power Performance Standards[2]

*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 137-187 minutes.
*Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 1.0-1.6 events.
Network Performance Standard 3: Improve Under Performing System Segments	The Company will identify underperforming circuit segments and outline improvement actions and their costs, and using the Open Reliability Reporting (ORR) process, evidence the outcome of the ORR process for the circuit segments chosen[3].
*Network Performance Standard 4: Supply Restoration	The Company will restore power outages due to loss of supply or damage to the distribution system within three hours to 80% of customers on average.
Customer Service Performance Standard 5: Telephone Service Level	The Company will answer 80% of telephone calls within 30 seconds. The Company will monitor customer satisfaction with the Company's Customer Service Associates and quality of response received by customers through the Company's eQuality monitoring system.
Customer Service Performance Standard 6: Commission Complaint Response/Resolution	The Company will a) respond to at least 95% of non-disconnect Commission complaints within three working days; b) respond to at least 95% of disconnect Commission complaints within four working hours; and c) resolve 95% of informal Commission complaints within 30 days, except in Utah where the Company will resolve 100% of informal Commission complaints within 30 days.

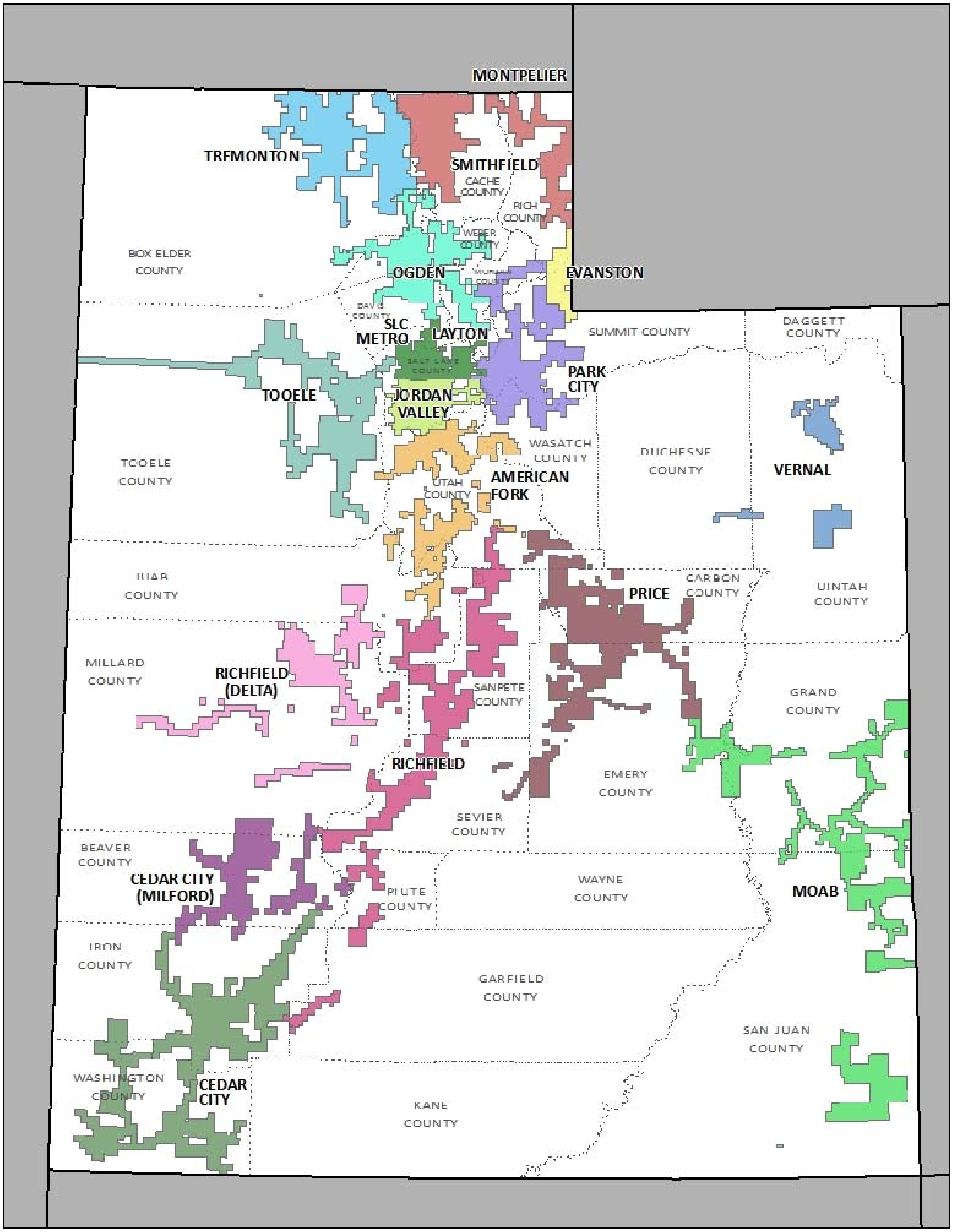
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

[2] On December 20, 2016, the Public Service Commission of Utah approved a modified electric service reliability performance baseline notification levels to 187 SAIDI minutes and 1.6 SAIFI events, with proposed baseline control zones of 137-187 SAIDI and 1.0-1.6 SAIFI (Docket NOS. 13-035-01 and 15-035-72).

[3] On June 1, 2107, in Dockets 15-035-72 and 08-035-55, the Commission approved modified reliability improvement methods with the Company's Open Reliability Reporting (ORR) process, in which the Commission concluded that the process reasonably satisfies the requirements of Utah Administrative Code R746-313-7(3)(e) relating to reporting on electric service reliability for areas whose reliability performance warrants additional improvement efforts. This change is reflected in Section 2.8.

1.3 Utah Distribution Service Area Map with Operating Areas/Districts

Below is a graphic showing the specific areas where the Company's distribution facilities are located.



2 RELIABILITY PERFORMANCE

For the reporting period, the Company's system average interruption duration index (SAIDI) performance was better than the baseline range (SAIDI between 137-187 minutes) and was within the system average interruption frequency index (SAIFI) performance baseline range (SAIFI between 1.0 and 1.6 events). Results for the underlying performance can be seen in subsections 2.1 and 2.2 below, where the Company's current underlying reliability results are shown with to the Company's control zones, which are colored green in the graphic. History reflecting these metrics is displayed in Sections 2.3 and 2.4. Baselines are discussed in Section 2.5. Cause code information, which is reported consistently with past Service Quality Review Reports, is shown in Section 2.6. Finally, Section 2.7 contains reporting information complies with features outlined in Utah Title 746.313.

During the reporting period, two major events[4] (both of which were accepted as major events by the Utah Commission upon recommendation of the Utah Division of Public Utilities) and five significant event days[5] were recorded.

Major Event Descriptions

Major Events		
Date	**Cause**	**SAIDI**
March 5-6, 2017	Storm – wind and snow	10.62
September 4-5, 2017	Loss of Transmission outages	6.20
	Total	**16.82**

- **March 5-6, 2017**
  On March 5, 2017, a storm bringing high winds, rain and snow began impacting areas across the state. The storm began in Salt Lake City, creating weather-related outages in the early morning. As the day progressed the storm continued to grow and by the afternoon areas across the state were experiencing weather related outages. During the event the state recorded wind gusts between 57 mph (Salt Lake City) and 67 mph (Cedar City). At 9:12 pm on March 5th, the number of customers without power peaked at 25,328 customers, the result of 136 concurrent outages being addressed by the response teams. High winds and snow-related outages accounted for 62% of all customer minutes lost and 68% of all customer outages. In addition, the high winds were a factor in tree-related outages, which accounted for 11% of all customer minutes lost, on both distribution and transmission circuits. This major event filing was accepted by the Utah Commission on May 5, 2017 in Docket 17-035-22.
- **September 4-5, 2017**
  From the evening of September 4 to the evening of September 5, 2017, Rocky Mountain Power experienced a series of unrelated loss of transmission outages which affected customers across the state. The first event occurred in Cedar City when a lightning storm passing through the area caused a transmission substation circuit breaker to trip. The outage affected five substations, feeding nine circuits, serving approximately 5,500 customers, with outage durations ranging from 3 hours 52 minutes to 4 hours 51 minutes. The next event affected service in Eagle Mountain, American Fork and Saratoga Springs when lightning arrestors

[4] Major event threshold shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2017	897,258	5.74	5,152,204

[5] Significant event days are 1.75 times the standard deviation of the company's natural log daily SAIDI results (by state or appropriate reliability reporting region).

failed. The events affected approximately 17,900 customers with outage durations ranging from 2 hours 41 minutes to 3 hours 33 minutes. The final event occurred in Uintah when high wind and a wildfire severely strained potions of a 46 kV transmission line. The event affected 5,200 customers for 1 hour 6 minutes. This major event filing was accepted by the Utah Commission on November 20, 2017 in Docket 17-035-57.

Significant Events

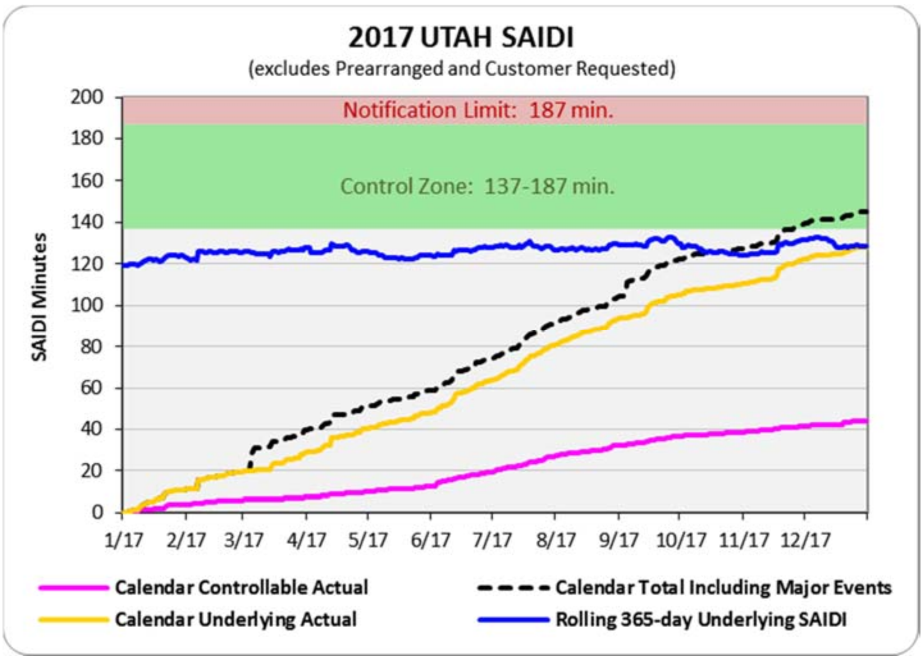
Significant event days add substantially to year-on-year cumulative performance results; fewer significant event days generally result in better reliability for the reporting period, while more significant event days generally mean poorer reliability results. During the reporting period five significant event days were recorded, which account for 15.6 SAIDI minutes; about 12% of the reporting period's underlying 129 SAIDI minutes. These significant events were triggered by weather impacts, loss of supply outages, trees, and pole fires. The relatively small quantity of days and their summary reliability metrics were contributory to the positive network reliability performance.

Significant Event Days					
Dates	**Cause: General Description**	**SAIDI**	**SAIFI**	**% Underlying SAIDI**	**% Underlying SAIFI**
February 7, 2017	Wind took down 4 poles in Northeast Utah	4.2	0.009	3%	1%
March 15, 2017	Loss of Substation in Salt Lake City	2.5	0.011	2%	1%
April 13, 2017	Wind Storm in Salt Lake City region	3.5	0.027	3%	3%
June 12, 2017	Wind Storm caused tree and pole fire outages in Salt Lake City	2.3	0.018	2%	2%
November 18, 2017	Loss of Transmission line in Garden City	3.0	0.005	2%	1%
	TOTAL	15.6	0.070	12%	7%

2.1 System Average Interruption Duration Index (SAIDI)

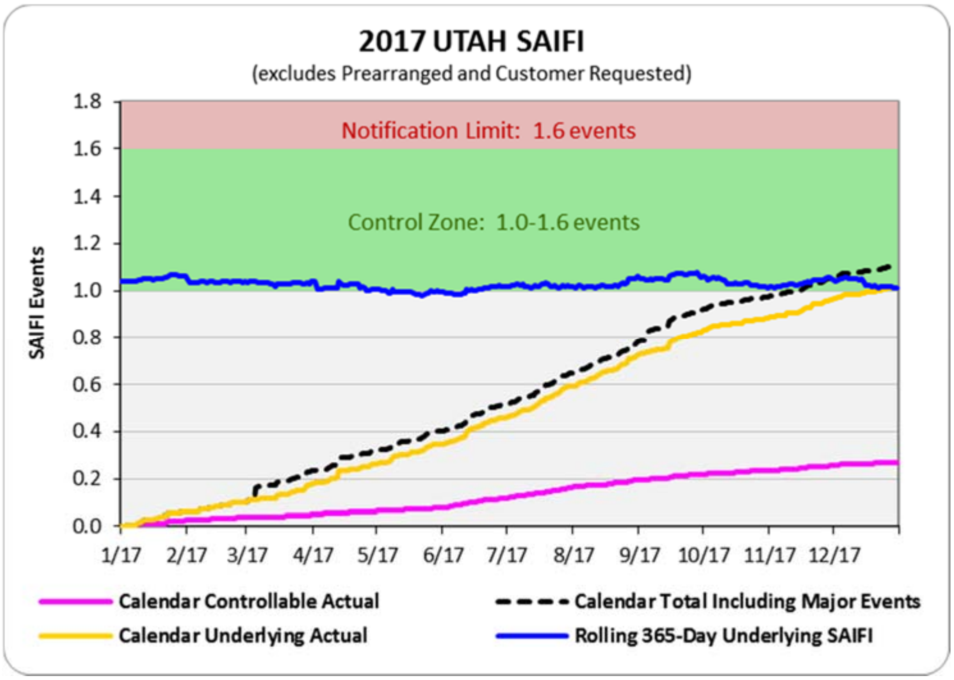
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below and in 2.2.

SAIDI	Reporting Period
Total	145
Underlying	129
Controllable Distribution	44



2.2 System Average Interruption Frequency Index (SAIFI)

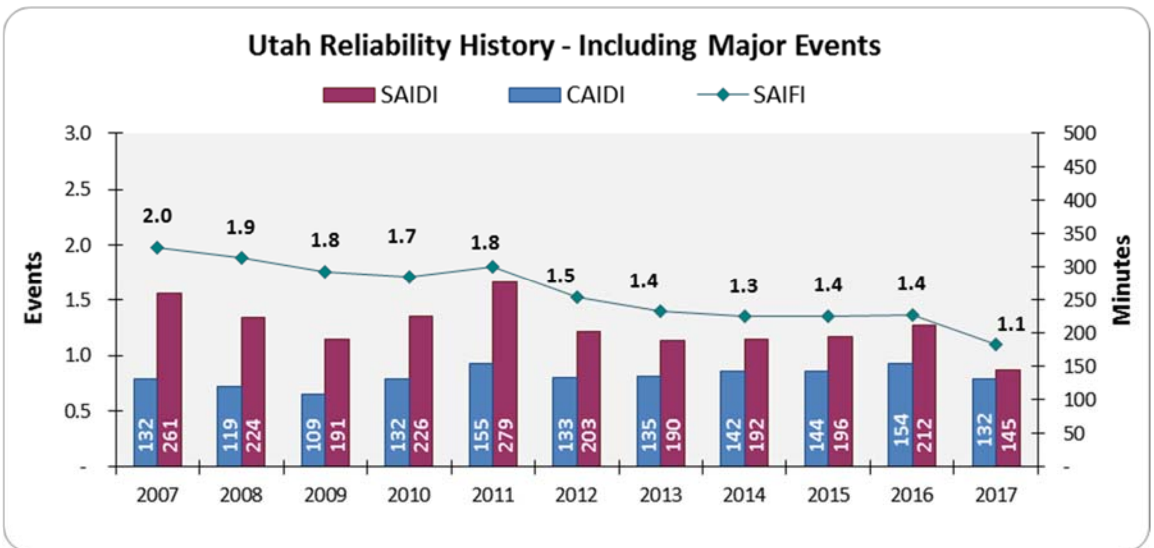
SAIFI	Reporting Period
Total	1.104
Underlying	1.013
Controllable Distribution	0.270

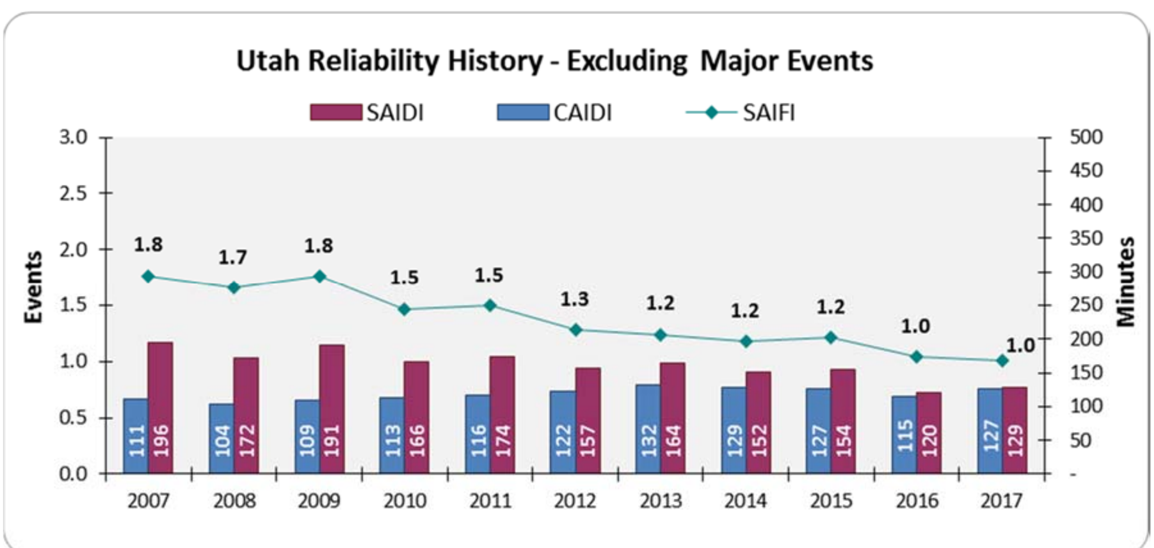


2.3 Reliability History

Historically the Company has improved reliability as measured by SAIDI and SAIFI reliability indices; at the same time outage response performance (CAIDI) has varied from year to year with no specific trend apparent. The SAIDI and SAIFI trends are further evidenced in Sections 2.4 and 2.6, where 365-day rolling performance trends are depicted. These indices (shown in the history charts below and in Sections 2.4 and 2.6) demonstrate the efficacy of the long-term improvement strategies targeted toward reducing the frequency of interruptions that the company under-took after the implementation of its automated outage management system. In recognition of the improved performance the Commission directed the Company to work with the Division to develop processes to establish modified performance baselines, which are detailed further in Section 2.6.

It is particularly noteworthy that these two metrics show durable improvement for both underlying and major event performance within the state, meaning that the system is more resilient on a day-to-day basis as well as when extreme weather or other system impacting events occur.

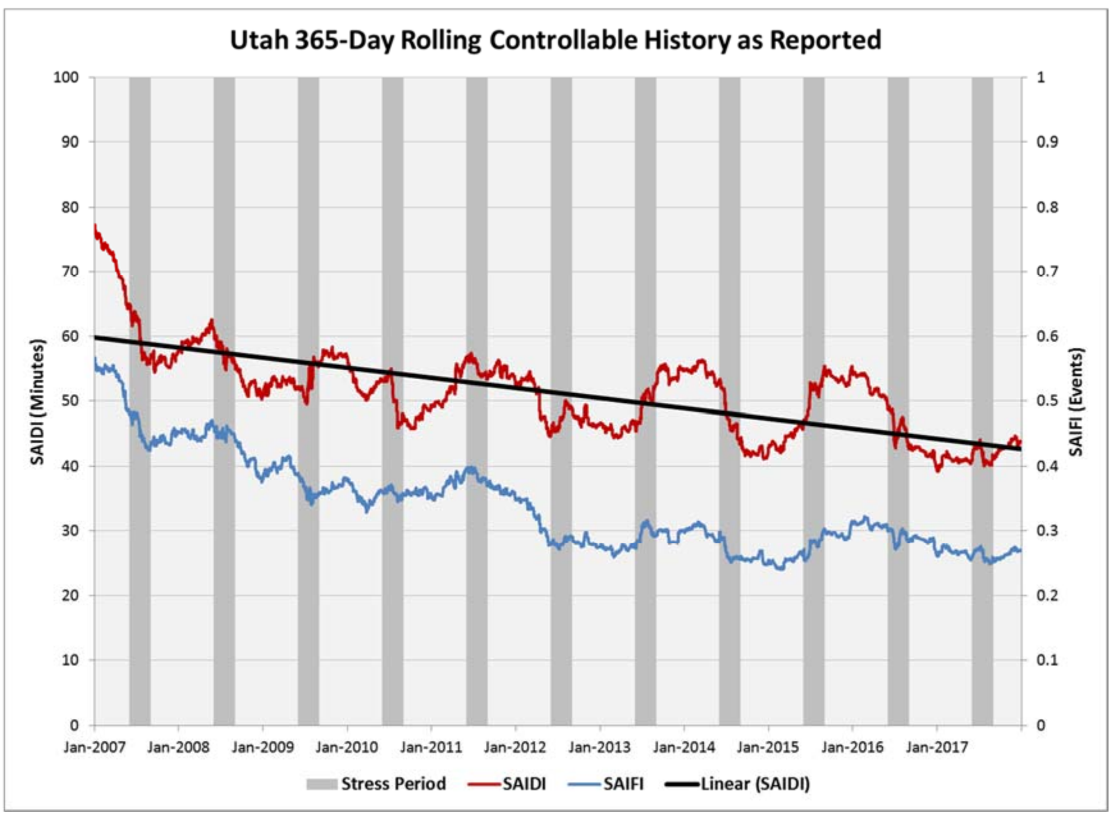




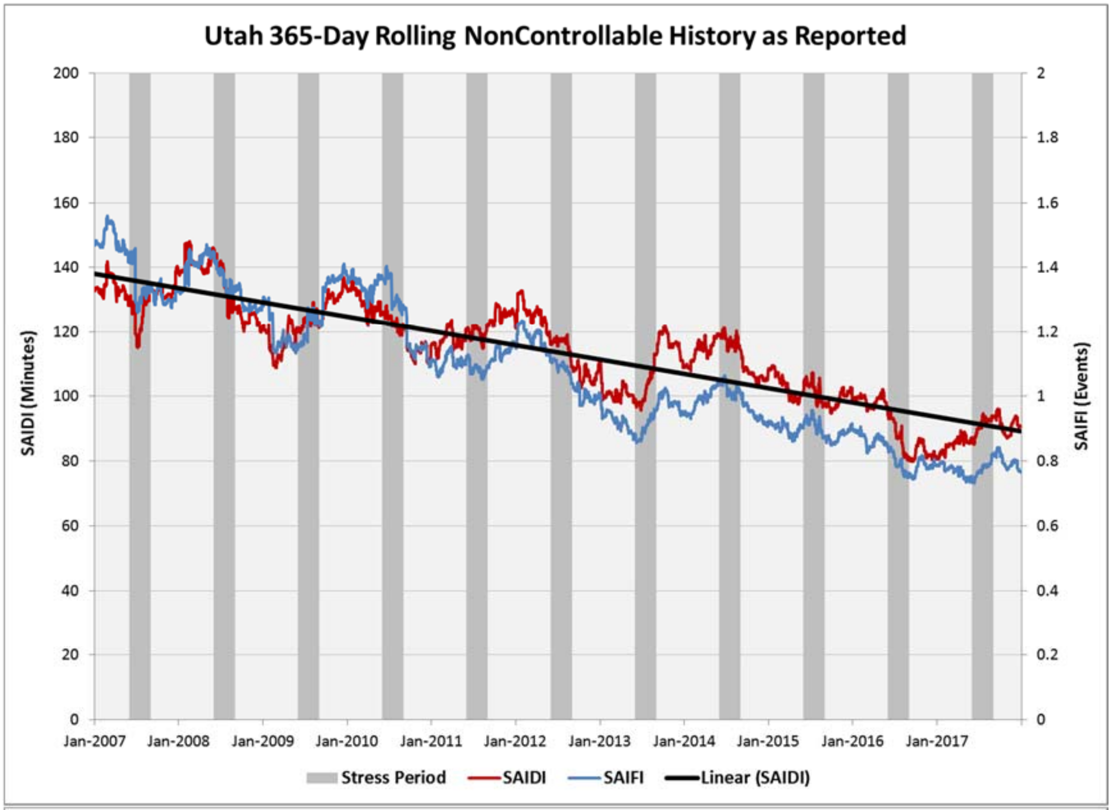
2.4 Controllable, Non-Controllable and Underlying Performance Review

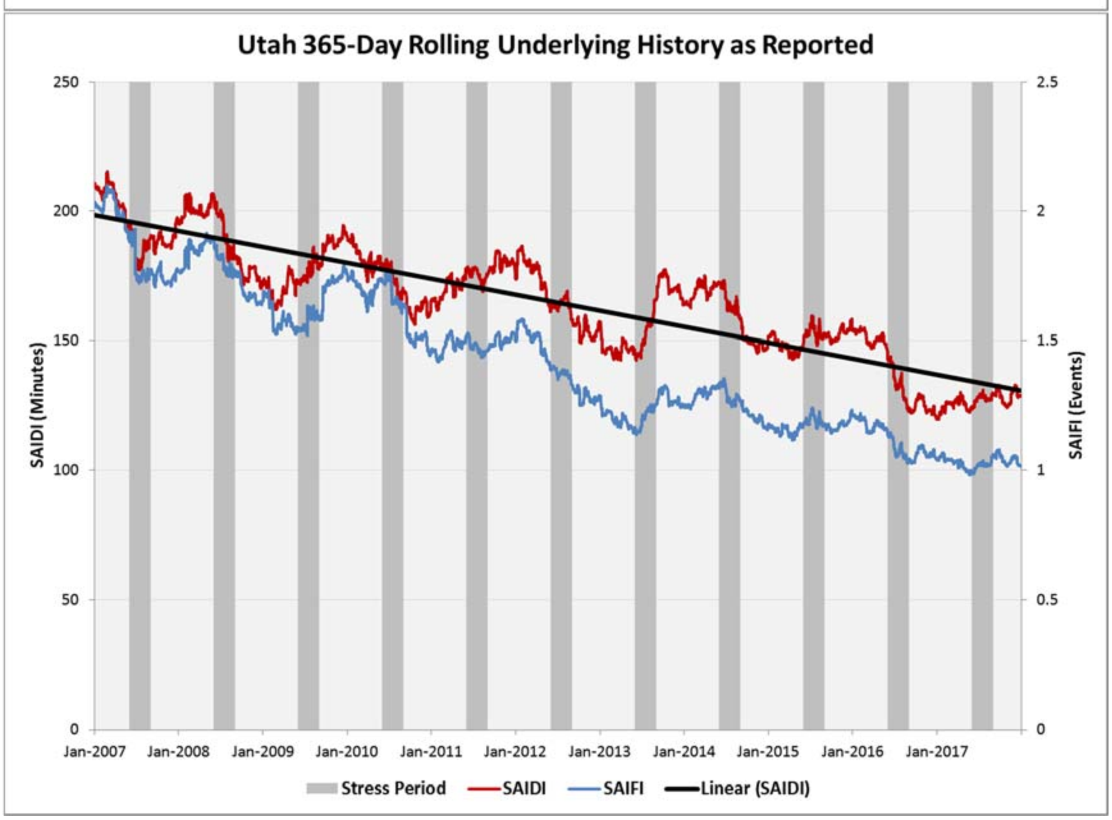
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. This categorization was titled Controllable Distribution outages and recognized that certain types of outages can be cost-effectively avoided. So, for example, animal-caused interruptions, as well as equipment failure interruptions have a less random nature than lightning caused interruptions; other causes have also been determined and are specified in Section 2.5. Engineers can develop plans to mitigate against controllable distribution outages and provide better future reliability at the lowest possible cost. At that time, there was concern that the Company would lose focus on non-controllable outages[6]. In order to provide insight into the response and history for those outages, the charts below distinguish amongst the outage groupings.

The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 365-day basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. In order to also focus on non-controllable outages, the Company has continued to improve its resilience to extreme weather using such programs as its visual assurance program to evaluate facility condition. It also has undertaken efforts to establish impacts of loss of supply events on its customers and deliver appropriate improvements when identified. It uses its web-based notification tool for alerting field engineering and operational resources when devices have exceeded performance thresholds in order to react as quickly as possible to trends in declining reliability. These notifications are conducted regardless of whether the outage cause was controllable or not.



[6] 3. The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.
4. The Company shall provide a supplemental filing, within 90 days, consisting of a process for measuring performance and improvements for the non-controllable events.


Utah 365-Day Rolling NonControllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
0
20
40
60
80
100
120
140
160
180
200
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
2
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Stress Period
SAIDI
SAIFI
Linear (SAIDI)


Utah 365-Day Rolling Underlying History as Reported
SAIDI (Minutes)
SAIFI (Events)
0
50
100
150
200
250
0
0.5
1
1.5
2
2.5
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

2.5 Cause Analysis Tables (Pre-Title 746-313 Modification)

Certain types of outages typically result in a large amount of customer minutes lost, but are infrequent, such as Loss of Supply outages. Others tend to be more frequent, but result in few customer minutes lost.

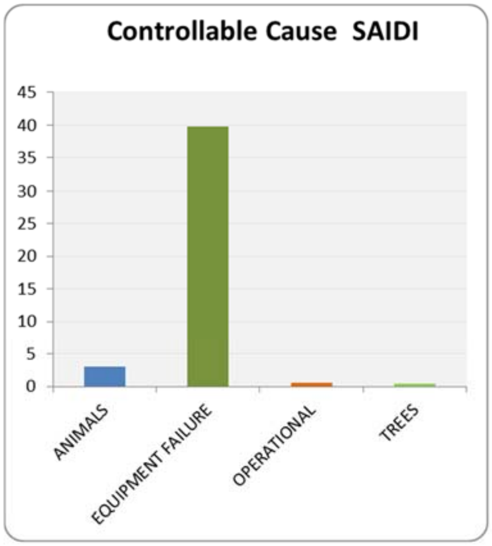
The cause analysis tables below detail SAIDI[7] and SAIFI by direct cause, with separate tables for the company's Controllable metrics and its Underlying metrics. (Both tables exclude major events.) Following the detail tables are pie charts showing the percentages attributed to each cause category with respect to three measures: total incidents, total customer minutes lost and total sustained customer interruptions, again with separate pie charts for Controllable and Underlying.

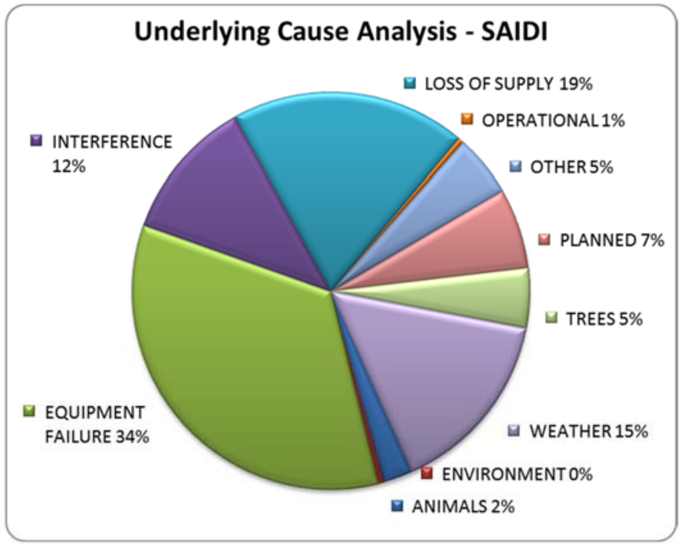
Note that the Underlying cause analysis table includes prearranged outages (*Customer Requested, Customer Notice Given, and Planned Notice Exempt* line items) with subtotals for their inclusion, while the grand totals in the table exclude these prearranged outages so that grand totals align with reported SAIDI and SAIFI metrics for the period. The following pie and historical cause detail reflect the cause category performance; these charts exclude prearranged outages, to align with the underlying reportable results. Following the charts, a table of definitions provides descriptive examples for each direct cause category. Further cause analysis is explored in Section 2.7.

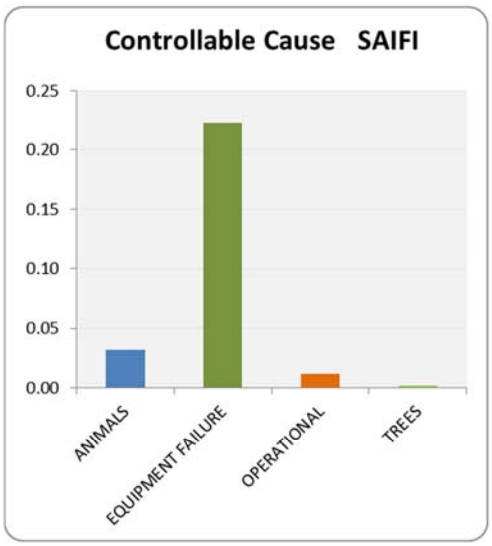
Utah Cause Analysis - Controllable 01/01/2017 - 12/31/2017					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	719,333	6,629	676	0.80	0.007
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,218,322	16,238	283	1.36	0.018
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	295,070	2,277	54	0.33	0.003
BIRD NEST (BMTS)	174,666	838	30	0.19	0.001
BIRD SUSPECTED, NO MORTALITY	326,957	3,004	134	0.36	0.003
ANIMALS	**2,734,348**	**28,986**	**1,177**	**3.05**	**0.032**
B/O EQUIPMENT	3,620,524	22,856	525	4.04	0.025
DETERIORATION OR ROTTING	31,019,973	168,203	4,818	34.57	0.187
OVERLOAD	1,021,141	8,817	112	1.14	0.010
RELAYS, BREAKERS, SWITCHES	663	7	33	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	3,839	13	29	0.00	0.000
EQUIPMENT FAILURE	**35,666,141**	**199,896**	**5,517**	**39.75**	**0.223**
FAULTY INSTALL	102,126	3,301	29	0.11	0.004
IMPROPER PROTECTIVE COORDINATION	39,882	635	12	0.04	0.001
INCORRECT RECORDS	22,762	1,286	34	0.03	0.001
INTERNAL CONTRACTOR	63,728	696	5	0.07	0.001
PACIFICORP EMPLOYEE - FIELD	278,562	4,942	18	0.31	0.006
OPERATIONAL	**507,060**	**10,860**	**98**	**0.57**	**0.012**
TREE - TRIMMABLE	392,532	1,727	93	0.44	0.002
TREES	**392,532**	**1,727**	**93**	**0.44**	**0.002**
Utah Including Prearranged	**39,300,080**	**241,469**	**6,885**	**43.80**	**0.269**

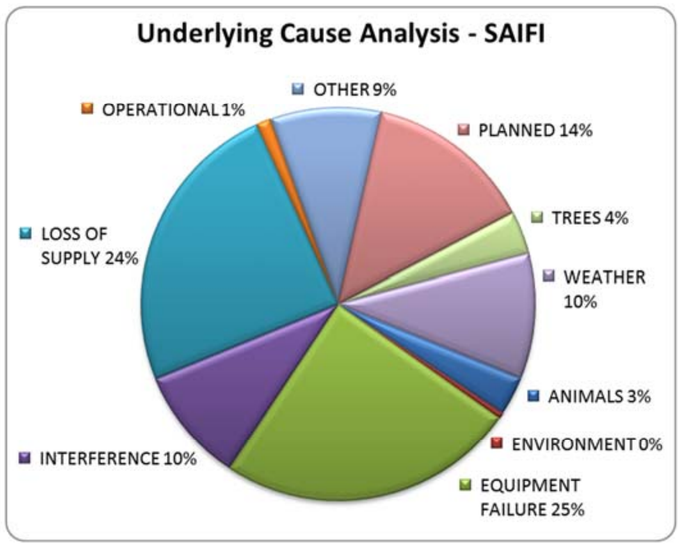
[7] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 879,258 (2017 Utah frozen customer count).

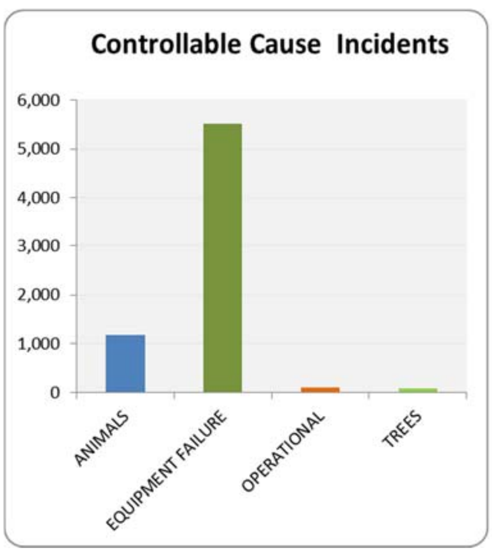
Utah Cause Analysis - Underlying 01/01/2017 - 12/31/2017					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	719,333	6,629	676	0.80	0.007
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,218,322	16,238	283	1.36	0.018
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	295,070	2,277	54	0.33	0.003
BIRD NEST (BMTS)	174,666	838	30	0.19	0.001
BIRD SUSPECTED, NO MORTALITY	326,957	3,004	134	0.36	0.003
ANIMALS	**2,734,348**	**28,986**	**1,177**	**3.05**	**0.032**
CONTAMINATION	66,236	588	4	0.07	0.001
FIRE/SMOKE (NOT DUE TO FAULTS)	451,970	3,766	22	0.50	0.004
ENVIRONMENT	**518,206**	**4,354**	**26**	**0.58**	**0.005**
B/O EQUIPMENT	3,620,524	22,856	525	4.04	0.025
DETERIORATION OR ROTTING	31,019,973	168,203	4,818	34.57	0.187
NEARBY FAULT	83,328	991	9	0.09	0.001
OVERLOAD	1,021,141	8,817	112	1.14	0.010
POLE FIRE	3,772,821	21,745	188	4.20	0.024
RELAYS, BREAKERS, SWITCHES	663	7	33	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	3,839	13	29	0.00	0.000
EQUIPMENT FAILURE	**39,522,289**	**222,632**	**5,714**	**44.05**	**0.248**
DIG-IN (NON-PACIFICORP PERSONNEL)	2,772,329	25,194	288	3.09	0.028
OTHER INTERFERING OBJECT	824,407	9,261	77	0.92	0.010
OTHER UTILITY/CONTRACTOR	320,658	2,996	71	0.36	0.003
VANDALISM OR THEFT	26,431	150	12	0.03	0.000
VEHICLE ACCIDENT	9,364,937	48,995	292	10.44	0.055
INTERFERENCE	**13,308,762**	**86,596**	**740**	**14.83**	**0.097**
FAILURE ON OTHER LINE OR STATION	420	1	2	0.00	0.000
LOSS OF FEED FROM SUPPLIER	19,372	174	2	0.02	0.000
LOSS OF GENERATOR	14,996	126	2	0.02	0.000
LOSS OF SUBSTATION	10,219,627	106,222	95	11.39	0.118
LOSS OF TRANSMISSION LINE	11,817,824	115,493	362	13.17	0.129
LOSS OF SUPPLY	**22,072,239**	**222,016**	**463**	**24.60**	**0.247**
FAULTY INSTALL	102,126	3,301	29	0.11	0.004
IMPROPER PROTECTIVE COORDINATION	39,882	635	12	0.04	0.001
INCORRECT RECORDS	22,762	1,286	34	0.03	0.001
INTERNAL CONTRACTOR	63,728	696	5	0.07	0.001
PACIFICORP EMPLOYEE - FIELD	278,562	4,942	18	0.31	0.006
TESTING/STARTUP ERROR	14,022	78	1	0.02	0.000
OPERATIONAL	**521,082**	**10,938**	**99**	**0.58**	**0.012**
OTHER, KNOWN CAUSE	315,587	8,156	163	0.35	0.009
UNKNOWN	5,513,057	74,476	1,094	6.14	0.083
OTHER	**5,828,644**	**82,632**	**1,257**	**6.50**	**0.092**
CONSTRUCTION	632,700	8,106	159	0.71	0.009
CUSTOMER NOTICE GIVEN	22,423,029	101,319	2,593	24.99	0.113
CUSTOMER REQUESTED	8,603,008	4,043	18	9.59	0.005
EMERGENCY DAMAGE REPAIR	6,185,641	99,378	1,126	6.89	0.111
INTENTIONAL TO CLEAR TROUBLE	463,561	12,650	66	0.52	0.014
PLANNED NOTICE EXEMPT	5,214,328	19,485	293	5.81	0.022
TRANSMISSION REQUESTED	237,063	5,253	9	0.26	0.006
PLANNED	**43,759,331**	**250,234**	**4,264**	**48.77**	**0.279**
TREE - NON-PREVENTABLE	5,233,313	30,458	489	5.83	0.034
TREE - TRIMMABLE	392,532	1,727	93	0.44	0.002
TREES	**5,625,845**	**32,185**	**582**	**6.27**	**0.036**
FREEZING FOG & FROST	333	4	2	0.00	0.000
ICE	1,098,165	1,887	17	1.22	0.002
LIGHTNING	2,949,317	29,536	333	3.29	0.033
SNOW, SLEET AND BLIZZARD	2,354,487	9,101	249	2.62	0.010
WIND	11,270,835	52,412	441	12.56	0.058
WEATHER	**17,673,137**	**92,940**	**1,042**	**19.70**	**0.104**
Utah Including Prearranged	**151,563,883**	**1,033,513**	**15,364**	**168.92**	**1.152**
Utah Excluding Prearranged	**115,323,518**	**908,666**	**12,460**	**128.53**	**1.013**

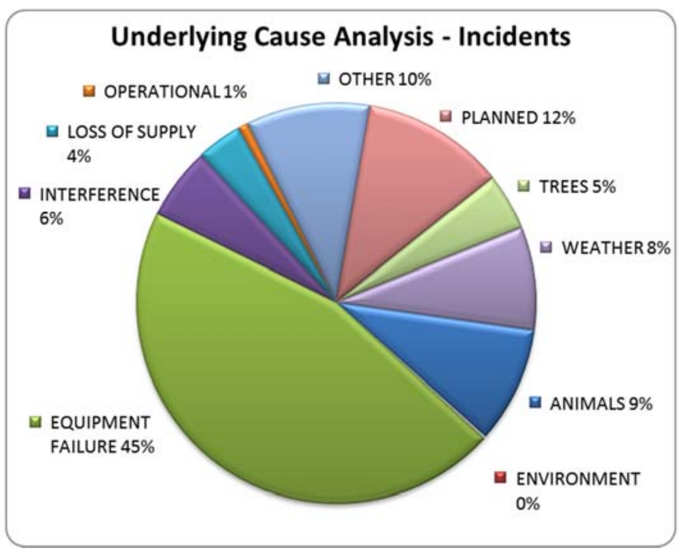

Controllable Cause SAIDI
45
40
35
30
25
20
15
10
5
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

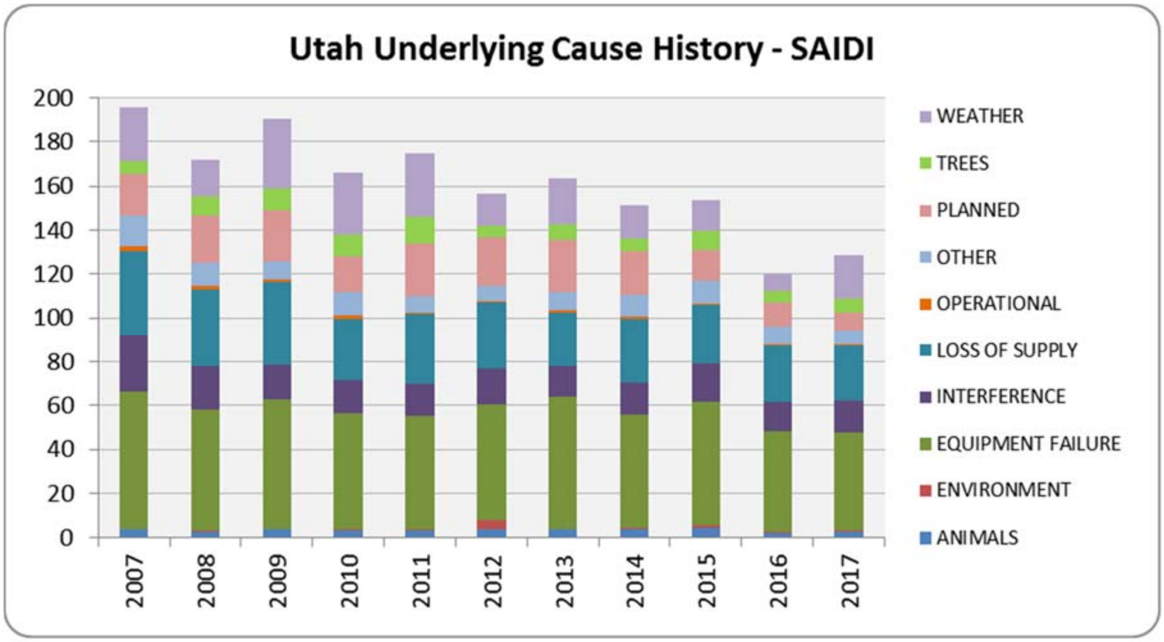

Underlying Cause Analysis - SAIDI
LOSS OF SUPPLY 19%
OPERATIONAL 1%
OTHER 5%
PLANNED 7%
TREES 5%
WEATHER 15%
ENVIRONMENT 0%
ANIMALS 2%
EQUIPMENT FAILURE 34%
INTERFERENCE 12%

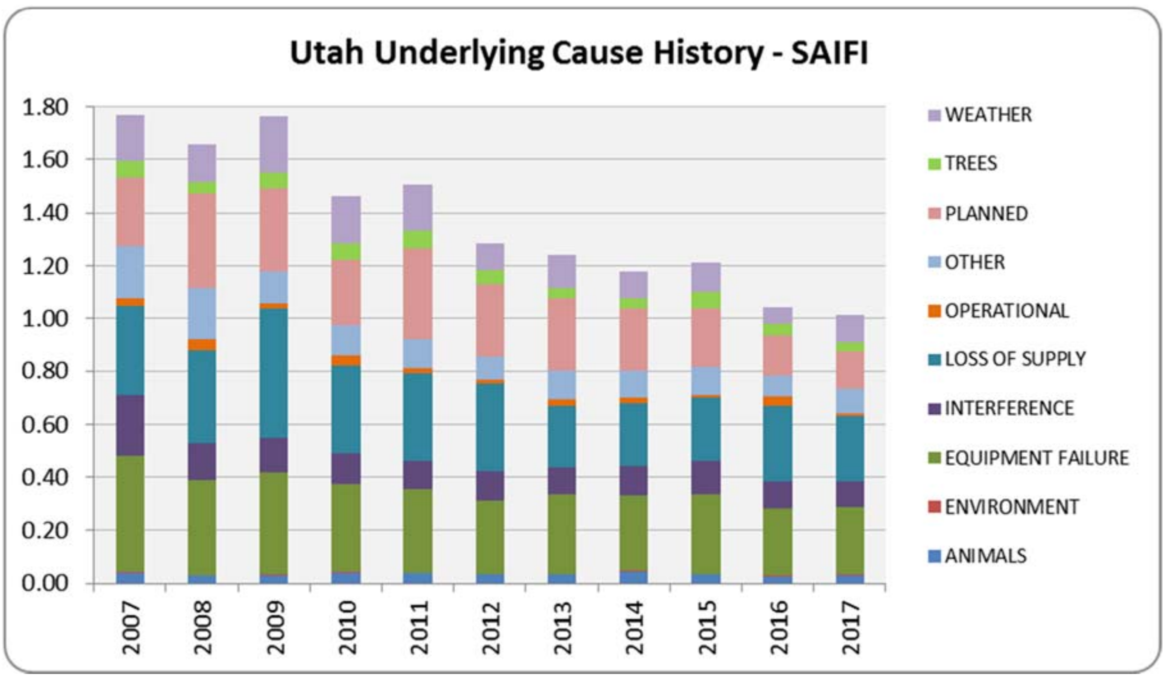

Controllable Cause SAIFI
0.25
0.20
0.15
0.10
0.05
0.00
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - SAIFI
OTHER 9%
OPERATIONAL 1%
PLANNED 14%
TREES 4%
WEATHER 10%
ANIMALS 3%
ENVIRONMENT 0%
EQUIPMENT FAILURE 25%
INTERFERENCE 10%
LOSS OF SUPPLY 24%


Controllable Cause Incidents
6,000
5,000
4,000
3,000
2,000
1,000
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - Incidents
OTHER 10%
OPERATIONAL 1%
PLANNED 12%
LOSS OF SUPPLY 4%
TREES 5%
INTERFERENCE 6%
WEATHER 8%
ANIMALS 9%
EQUIPMENT FAILURE 45%
ENVIRONMENT 0%


Utah Underlying Cause History - SAIDI
200
180
160
140
120
100
80
60
40
20
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

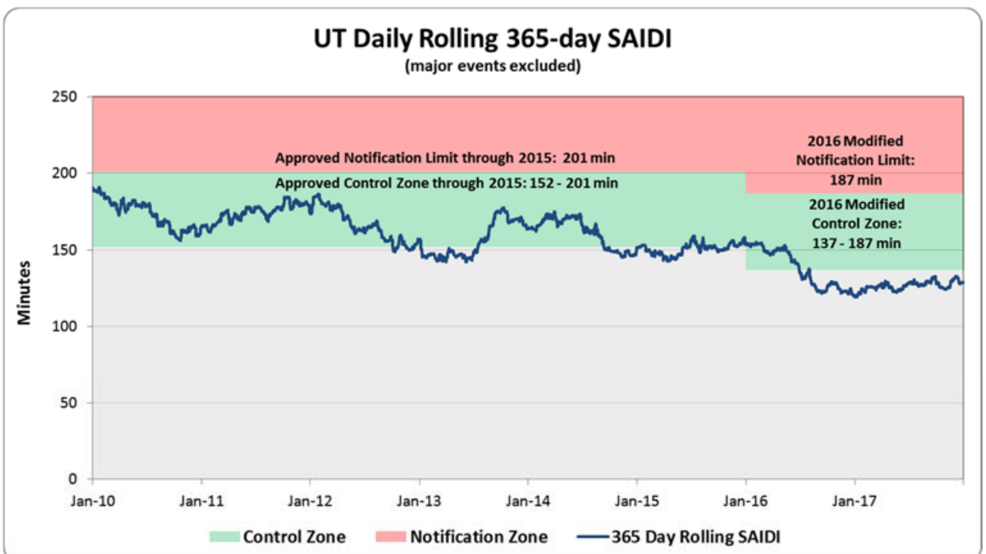

Utah Underlying Cause History - SAIFI
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

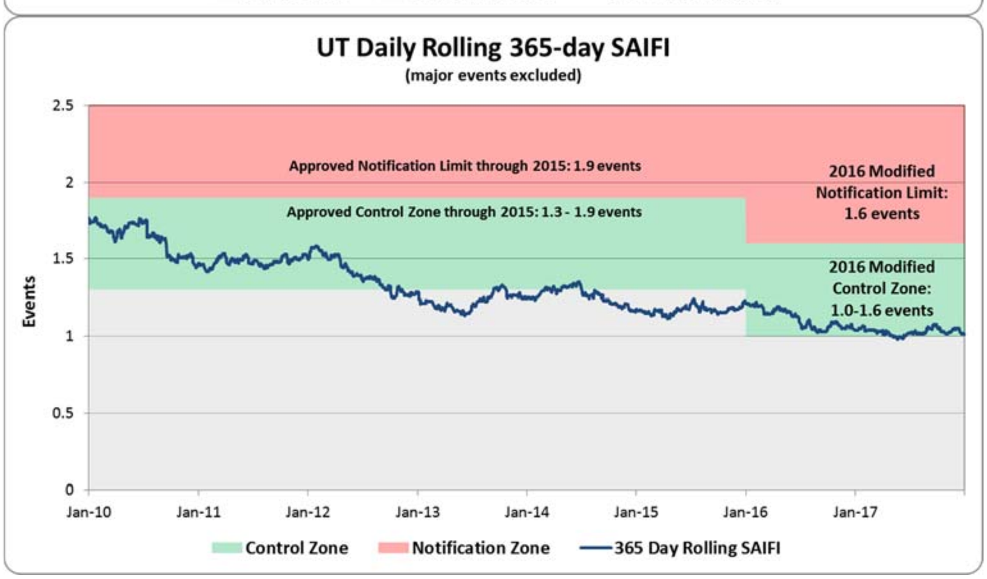
Direct Cause Category	Category Definition & Example/Direct Cause	
Animals	Any problem nest that requires removal, relocation, trimming, etc.; any birds, squirrels or other animals, whether or not remains found.	
	• Animal (Animals) • Bird Mortality (Non-protected species) • Bird Mortality (Protected species)(BMTS)	• Bird Nest • Bird or Nest • Bird Suspected, No Mortality
Environment	Contamination or Airborne Deposit (i.e. salt, trona ash, other chemical dust, sawdust, etc.); corrosive environment; flooding due to rivers, broken water main, etc.; fire/smoke related to forest, brush or building fires (not including fires due to faults or lightning).	
	• Condensation/Moisture • Contamination • Fire/Smoke (not due to faults) • Flooding	• Major Storm or Disaster • Nearby Fault • Pole Fire
Equipment Failure	Structural deterioration due to age (incl. pole rot); electrical load above limits; failure for no apparent reason; conditions resulting in a pole/cross arm fire due to reduced insulation qualities; equipment affected by fault on nearby equipment (e.g., broken conductor hits another line).	
	• B/O Equipment • Overload	• Deterioration or Rotting • Substation, Relays
Interference	Willful damage, interference or theft; such as gun shots, rock throwing, etc.; customer, contractor or other utility dig-in; contact by outside utility, contractor or other third-party individual; vehicle accident, including car, truck, tractor, aircraft, manned balloon; other interfering object such as straw, shoes, string, balloon.	
	• Dig-in (Non-PacifiCorp Personnel) • Other Interfering Object • Vandalism or Theft	• Other Utility/Contractor • Vehicle Accident
Loss of Supply	Failure of supply from Generator or Transmission system; failure of distribution substation equipment.	
	• Failure on other line or station • Loss of Feed from Supplier • Loss of Generator	• Loss of Substation • Loss of Transmission Line • System Protection
Operational	Accidental Contact by PacifiCorp or PacifiCorp's Contractors (including live-line work); switching error; testing or commissioning error; relay setting error, including wrong fuse size, equipment by-passed; incorrect circuit records or identification; faulty installation or construction; operational or safety restriction.	
	• Contact by PacifiCorp • Faulty Install • Improper Protective Coordination • Incorrect Records • Internal Contractor	• Internal Tree Contractor • Switching Error • Testing/Startup Error • Unsafe Situation
Other	Cause Unknown; use comments field if there are some possible reasons.	
	• Invalid Code • Other, Known Cause	• Unknown
Planned	Transmission requested, affects distribution sub and distribution circuits; Company outage taken to make repairs after storm damage, car hit pole, etc.; construction work, regardless if notice is given; rolling blackouts.	
	• Construction • Customer Notice Given • Energy Emergency Interruption • Intentional to Clear Trouble	• Emergency Damage Repair • Customer Requested • Planned Notice Exempt • Transmission Requested
Tree	Growing or falling trees	
	• Tree-Non-preventable • Tree-Trimmable	• Tree-Tree felled by Logger
Weather	Wind (excluding windborne material); snow, sleet or blizzard, ice, freezing fog, frost, lightning.	
	• Extreme Cold/Heat • Freezing Fog & Frost • Wind	• Lightning • Rain • Snow, Sleet, Ice and Blizzard

2.6 Baseline Performance

In compliance with Utah Reliability Reporting Rules, the Company developed performance baselines that it subsequently filed for approval (based on 2008-2012 history). These baselines were approved, but stakeholders advocated that periodically refreshing baseline levels would be beneficial. As a result on December 20, 2016, the Public Service Commission of Utah approved modified electric service reliability performance baseline notification levels (Docket NOS. 13-035-01 and 15-035-72). The original and modified baselines are shown below.

	SAIDI (Minutes)			SAIFI (Events)		
	Average	Lower Value Control Zone	Upper Value Control Zone	Average	Lower Value Control Zone	Upper Value Control Zone
Prior Baseline	-	152	201	-	1.3	1.9
2016 Modified Baseline	162	137	187	1.36	1.0	1.6





2.7 Reliability Reporting Post-Rule R.746-313 Modifications

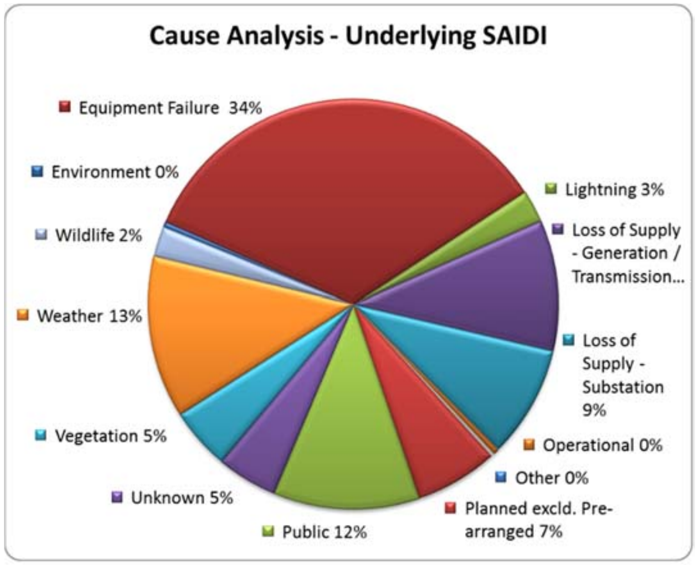
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Administrative Code R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least partially redundant or segmented differently than has been provided in the past. Thus, in order to include both, the new required segmentation in addition to the pre-reporting rule segmentation was considered the ideal reporting approach. As this report evolves, certain of these redundancies may be eliminated.

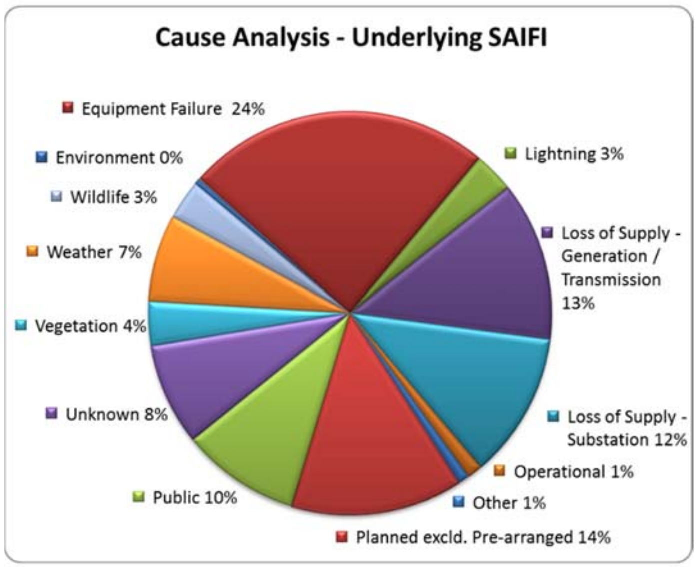
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to MAIFIe are required.

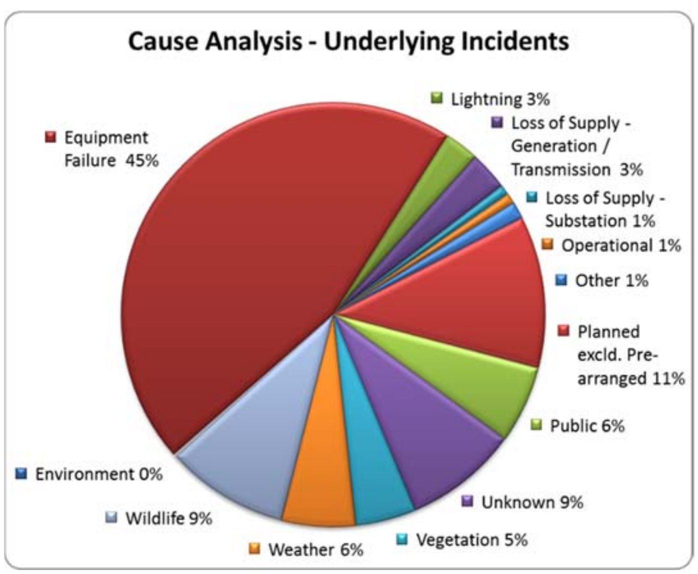
Major Events and Prearranged Excluded*	2013				2014				2015				2016				2017			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	164	1.2	132	0.81	152	1.2	129	1.21	154	1.2	127	1.48	120	1.0	115	1.76	129	1.0	127	1.11
OP AREA																				
AMERICAN FORK	126	1.3	99		113	1.0	109		134	1.1	128		92	1.0	93		77	0.8	102	
CEDAR CITY	225	1.8	127		170	1.1	151		238	1.6	146		174	1.5	116		183	1.7	109	
CEDAR CITY (MILFORD)	707	3.3	213		891	3.3	271		334	3.6	92		650	4.9	132		565	2.5	230	
JORDAN VALLEY	106	0.7	145		103	0.7	141		128	1.0	126		100	0.8	131		109	0.8	139	
LAYTON	105	1.0	109		108	0.8	127		122	1.1	109		90	0.9	103		115	0.8	149	
MOAB	284	1.9	147		412	2.3	181		426	3.5	122		278	3.0	93		190	2.4	80	
OGDEN	168	1.4	122		218	1.9	113		175	1.4	123		120	1.0	120		119	0.9	138	
PARK CITY	232	1.5	155		147	1.1	140		247	1.5	162		183	1.6	117		227	1.4	159	
PRICE	514	1.8	293		394	2.2	180		230	1.8	127		340	3.3	104		171	2.5	69	
RICHFIELD	469	3.4	138		181	1.7	104		303	2.2	137		132	1.3	101		187	2.0	95	
RICHFIELD (DELTA)	316	3.7	85		202	1.9	108		536	3.0	180		215	2.1	103		139	1.3	105	
SLC METRO	170	1.2	139		145	1.1	129		107	0.9	125		104	0.9	113		114	1.0	111	
SMITHFIELD	81	0.7	117		114	0.9	126		236	1.6	150		117	1.0	118		139	0.9	149	
TOOELE	137	1.3	103		239	2.1	115		129	1.3	103		161	1.1	151		140	1.4	100	
TREMONTON	335	3.3	102		216	2.0	111		462	4.2	110		399	3.1	129		200	2.0	99	
VERNAL	160	2.1	75		119	1.2	101		68	0.8	87		53	0.6	84		77	0.8	96	

* except MAIFIe

Utah Cause Category	2013		2014		2015		2016		2017	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	0	0.0	1	0.0	1	0.0	1	0.0	1	0.0
Equipment Failure	60	0.3	51	0.3	56	0.3	45	0.2	44	0.2
Lightning	9	0.1	7	0.1	6	0.1	3	0.0	3	0.0
Loss of Supply - Generation/Transmission	19	0.2	23	0.2	22	0.2	13	0.2	13	0.1
Loss of Supply - Substation	6	0.0	6	0.0	5	0.0	13	0.1	11	0.1
Operational	1	0.0	1	0.0	1	0.0	1	0.0	1	0.0
Other	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	24	0.3	20	0.2	14	0.2	11	0.2	8	0.1
Public	14	0.1	15	0.1	18	0.1	14	0.1	15	0.1
Unknown	8	0.1	10	0.1	10	0.1	7	0.1	6	0.1
Vegetation	7	0.0	6	0.0	8	0.1	5	0.0	6	0.0
Weather	12	0.1	8	0.0	8	0.0	5	0.0	16	0.1
Wildlife	4	0.0	4	0.0	5	0.0	2	0.0	3	0.0
UTAH Underlying	**164**	**1.2**	**152**	**1.2**	**154**	**1.2**	**120**	**1.0**	**129**	**1.0**


Cause Analysis - Underlying SAIDI
Equipment Failure 34%
Environment 0%
Wildlife 2%
Weather 13%
Vegetation 5%
Unknown 5%
Public 12%
Planned excld. Pre-arranged 7%
Other 0%
Operational 0%
Loss of Supply - Substation 9%
Loss of Supply - Generation / Transmission...
Lightning 3%


Cause Analysis - Underlying SAIFI
Equipment Failure 24%
Environment 0%
Wildlife 3%
Weather 7%
Vegetation 4%
Unknown 8%
Public 10%
Planned excld. Pre-arranged 14%
Other 1%
Operational 1%
Loss of Supply - Substation 12%
Loss of Supply - Generation / Transmission 13%
Lightning 3%


Cause Analysis - Underlying Incidents
Lightning 3%
Loss of Supply - Generation / Transmission 3%
Loss of Supply - Substation 1%
Operational 1%
Other 1%
Planned excld. Pre-arranged 11%
Public 6%
Unknown 9%
Vegetation 5%
Weather 6%
Wildlife 9%
Environment 0%
Equipment Failure 45%

2.8 Improve Reliability Performance in Areas of Concern

Over the past decade the Company has developed approaches, including tools, automated and manual processes and methods to improve reliability. As it has done so, the Company's ability to diagnose portions of the system requiring improvement has improved, which yields its legacy "Worst Performing Circuit" program obsolete, as described in section 2.8.4. As a result it devised a more contemporary approach to identifying improvement plans, determining the value of those plans and monitoring to ensure that results delivered meet or exceed expected targets. This program was named Open Reliability Reporting (ORR).

The ORR process shifts the Company's reliability program from a circuit-based view reliant on blended reliability metrics (using circuit SAIDI, SAIFI and MAIFI) to a more strategic and targeted approach based upon recent trends in performance of the local area, as measured by customer minutes interrupted (from which SAIDI is derived). The decision to fund one performance improvement project versus another is based on cost effectiveness as measured by the cost per avoided annual customer minute interrupted. However, the cost effectiveness measure will not limit funding of improvement projects in areas of low customer density where cost effectiveness per customer may not be as high as projects in more densely populated areas.

2.8.1 Reliability Work Plans

The Company has worked to improve reliability through Reliability Work Plans. To assist in identification of problem areas, Area Improvement Teams (AIT) meetings and Frequent Interrupters Requiring Evaluation (FIRE) reports have been established. On a daily basis the Company systems alert operations and engineering team members regarding outages experienced at interrupting devices (circuit breakers, line reclosers and fuses). When repetition occurs, it is an indicator that system improvements may be needed. On a routine basis, local operations and engineering team members review the performance of the network using geospatial and tabular tools to look for opportunities to improve reliability. As system improvement projects are identified, cost estimates of reliability improvement and costs to deliver that improvement are prepared. If the project's cost effectiveness metrics are favorable, i.e. low cost and high avoidance of future customer minutes interrupted, the project is approved for funding and the forecast customer minutes interrupted are recorded for subsequent comparison. This process allows individual districts to take ownership and identify the greatest impact to their customers. Rather than focusing on a large area at high costs, districts can focus on problem areas or devices.

2.8.2 Project approvals by district

The identification of projects is an ongoing process throughout the year. An approval team reviews projects weekly and once approved, design and construction begins. Upon completion of the construction, the project is identified for follow up review of effectiveness. One year after completion, routine assessments of performance are prepared. This comparison is summarized for all projects for each year's plans, and actual versus forecast results are assessed to determine whether targets were met or if additional work may be required. The table below is provided to demonstrate the measures the Company believes represents cost/effectiveness measures that are important in determining the success of the projects that have been completed.

UTAH

January 1 – December 31, 2017

2015-2017 District Projects									
Approval Metrics			Effectiveness Metrics						In Progress
District	Project count	Budgeted Cost/CML	Plans Meeting Goals (>1 year since project completion)	Estimated Avoided annual CML	Actual Avoided annual CML	Budgeted Cost per annual avoided CML	Actual Cost per annual avoided CML	Plans Not Meeting Goals (not included in metrics)	Plans waiting for information
American Fork	40	$0.56	13	449,026	595,064	$0.97	$0.66	3	24
Cedar City	9	$1.16	2	570,766	1,438,431	$0.61	$0.19	2	5
Cedar City (Milford)	5	$1.02	1	31,251	70,510	$2.46	$2.09	1	3
Jordan Valley	65	$1.27	17	845,175	1,284,468	$0.91	$0.84	5	43
Layton	18	$0.85	7	325,246	631,199	$1.11	$0.73	2	9
Moab	9	$1.40	1	133,441	248,807	$0.19	$0.06	3	5
Ogden	36	$0.81	10	1,472,981	2,456,440	$0.55	$0.32	1	25
Park City	26	$0.60	10	1,085,227	2,262,916	$0.50	$0.31	3	13
Price	14	$0.37	4	37,163	46,937	$3.93	$4.00	1	9
Richfield	11	$2.13	1	30,054	31,960	$2.73	$1.25	1	9
Richfield (Delta)	6	$4.60	0	-	-	$0.00	$0.00	0	6
SLC Metro	50	$0.58	14	663,451	1,917,814	$1.04	$0.54	3	33
Smithfield	12	$1.62	0	-	-	$0.00	$0.00	2	10
Tooele	12	$0.55	3	188,434	239,634	$0.67	$0.56	1	8
Tremonton	11	$0.61	1	58,070	183,408	$2.58	$0.49	0	10
Vernal	14	$0.95	7	135,987	294,743	$0.85	$0.61	0	7
Total	**338**	**$0.83**	**91**	**6,026,272**	**11,702,331**	**$0.77**	**$0.47**	**28**	**219**

2.8.3 Reduce CPI for Worst Performing Circuits by 20%

Prior to the Open Reliability Reporting process, the Company reviewed circuits for performance. One of the measures that it used was called circuit performance indicator (CPI), which was a blended weighting of key reliability metrics covering a three-year period. The higher the number, the poorer the blended performance the circuit is delivering. As part of the Company's Performance Standards Program, it annually selected a set of Worst Performing Circuits for improvements, which were to be completed within two years of selection. Within five years of selection, the average performance of the five-selection circuits must have improved by at least 20% (as measured by comparing current performance against baseline performance).

2.8.4 Circuit Performance Score Updates for Prior-Year Selections

Annually, the company tracked the performance of circuits designated in the Worst Performing Circuits program, until the Program Year has successfully met the target score.

WORST PERFORMING CIRCUITS	STATUS	BASELINE[8]	Performance 12/31/2017
Program Year 17: (CY2016)			
Red Mountain 33	IN PROGRESS	1283	1624
Fountain Green 12	IN PROGRESS	266	173
Middleton 24	IN PROGRESS	253	285
Willowridge 11	IN PROGRESS	177	140
Summit Park 11	IN PROGRESS	116	118
TARGET SCORE = **335**		**419**	**468**
Program Year 16: (CY2015)			
Nibley 21	COMPLETE	179	335
Brighton 12	COMPLETE	270	134
Rattlesnake 22	COMPLETE	456	475
Decker Lake 12	COMPLETE	167	49
Toquerville 31	COMPLETE	475	210
TARGET SCORE = **248**	Target Met	**309**	**241**
Program Year 15: (CY2014)			
Skull Valley 11	COMPLETE	468	192
Fort Douglas 13	COMPLETE	417	100
Parowan Valley 25	COMPLETE	408	281
Brighton 21	COMPLETE	364	214
Bush 12	COMPLETE	281	137
TARGET SCORE = **248**	Target Met	**310**	**185**

[8] RMP transitioned fully to applying CPI99 rather than CPI05 based on prior review with Stakeholders where the limitations of CPI05 were explored. Due to inclusion of major event and transmission outages, reporting period comparisons yielded a limited ability to identify the benefits of improvements made for each of the circuits. The application of CPI99 proved to demonstrate more consistently how performance comparisons could be made.

UTAH January 1 – December 31, 2017

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 12/31/2017
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	129
Eden 11	COMPLETE	116	127
Bush 11	COMPLETE	228	110
Pioneer 12	COMPLETE	177	95
Grantsville 12	COMPLETE	250	107
TARGET SCORE = 108		**135**	**114**
Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	210
East Bench 12	COMPLETE	112	23
Clinton 11	COMPLETE	133	43
Redwood 16	COMPLETE	145	71
Orangeville 11	COMPLETE	114	45
TARGET SCORE = **114**	**Target Met**	**142**	**78**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	61
Huntington City 12	COMPLETE	285	77
Magna 15	COMPLETE	140	28
Gunnison 12	COMPLETE	110	112
Capitol 11	COMPLETE	129	52
TARGET SCORE = **134**	**Target Met**	**167**	**66**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	49
North Bench 13	COMPLETE	95	48
Newgate 14	COMPLETE	164	40
Newton 12	COMPLETE	105	45
St Johns 11	COMPLETE	547	216
TARGET SCORE = **162**	**Target Met**	**203**	**80**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	62
Mathis 12	COMPLETE	132	122
Parrish 11	COMPLETE	137	35
Valley Center 11	COMPLETE	169	15
Hammer 15	COMPLETE	95	28
TARGET SCORE = **104**	**Target Met**	**129**	**52**

Note: Goals were met for Program Years 1 through 13 and filed in prior reporting periods; however, data for Program Years 10-13 are retained in this report in order to show circuit selections over a longer period of history for discussion purposes.

2.9 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
Reporting Period Cumulative = 83%					
January	February	March	April	May	June
76%	84%	80%	74%	91%	82%
July	August	September	October	November	December
82%	90%	89%	90%	79%	81%

2.10 CAIDI Performance

The table below shows the average time, during the reporting period, for outage restoration. This augments previous reporting for the percent of customers whose power was restored within 3 hours of notification of an outage event and uses IEEE industry indices.

CAIDI (Average Outage Duration)	
Underlying Performance	127 minutes
Total Performance	132 minutes

2.11 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	81%
PS6a) Respond to commission complaints within 3 days	95%	100%
PS6b) Respond to commission complaints regarding service disconnects within 4 hours	95%	100%
PS6c) Address commission[9] complaints within 30 days	100%	100%

[9] Rocky Mountain Power follows the definitions for informal and formal complaints as set forth in the Utah Code, Title 54, Public Utilities Statutes and Public Service Commission Rules, R746-200-8 Informal review (A) and Commission review (D).

2.12 Utah Commitment U1

To identify when a 'wide-scale' outage has occurred, the company examines call data for customers who have selected either the power emergency or power outage option within the company's call menu. However, in order to report on performance during a 'wide-scale' outage, the company must use network information, which provides information for all call types, not just outage calls. Therefore, using the menu level data the company has identified the time intervals that exceed the agreed upon standard 2,000 calls/hour, and reports the network level statistics for the same intervals.

For the year, there were seven dates identified as a wide-scale outage days; call statistics are shown in the table below. On January 3rd a winter storm heavily affected parts of Southern Oregon and Northern California as snow laden trees and lines were downed resulting in major events in both states. On February 3rd a loss of feed from supplier event occurred in the Willamette Valley region of Oregon when the transmission feed from the Bonneville Power Administration was lost, resulting in approximately 14,931 customers out of service for durations ranging from 42 minutes to 1 hour 8 minutes. On March 3rd call volumes exceeded the agreed upon standard calls/hour due to customer billing concerns given the significant winter bills that had just been received; there were no significant outages on this day. On March 6th Salt Lake City experienced an outage due to a loss of substation. The event affected 3,001 customers with outage durations ranging from 4 hours to 6 hours 43 minutes. On April 7th a wind storm blew through Southern Oregon and Northern California causing wide spread outages due to downed trees and transmission line structures. The event affected nearly 219,000 Pacific Power customers and resulted in major events in both Oregon and California. On September 12th, Rock Springs, Wyoming, experienced a loss of substation outage due to damaged equipment. The event affected almost 12,000 customers for 1 hour 18 minutes. On November 7th, Washington experienced a major event when a 69 kV conductor splice failed during an off-normal configuration. The failure de-energized five substations which feed 14 circuits serving over 17,800 customers.

Date	Interval start/finish (Mountain Time)		Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
1/3/2017	11:00	11:14	670	0	7	97	33
	11:15	11:29	651	23	13	171	69
	11:30	11:44	722	0	8	93	29
	11:45	11:59	738	3	10	109	29
	12:00	12:14	746	8	16	208	91
	12:15	12:29	713	12	27	195	88
	12:30	12:44	709	16	12	124	64
2/3/2017	11:45	11:59	1556	205	117	348	75
	12:00	12:14	1083	63	23	123	17
	12:15	12:29	1218	84	20	197	36
	12:30	12:44	1082	44	8	109	35
	12:45	12:59	777	5	17	228	94
3/3/2017	9:00	9:14	557	0	6	170	52
	9:15	9:29	641	0	10	146	62
	9:30	9:44	537	0	10	137	40
	9:45	9:59	496	0	3	139	14
	10:00	10:14	493	0	1	118	16

UTAH January 1 – December 31, 2017

Date	Interval start/finish (Mountain Time)	Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds	Date
3/6/2017	9:30	9:44	890	45	18	280	69
	9:45	9:59	744	4	8	178	46
	10:00	10:14	708	0	18	151	49
	10:15	10:29	729	11	10	145	53
	10:30	10:44	681	0	24	222	59
	10:45	10:59	652	0	12	134	54
	11:00	11:14	660	0	22	158	82
	11:15	11:29	709	48	29	237	113
	11:30	11:44	676	2	8	214	27
4/7/2017	8:00	8:14	2660	614	58	214	94
	8:15	8:29	2027	387	31	1057	49
	8:30	8:44	2037	288	55	874	66
	8:45	8:59	2008	300	49	485	81
	9:00	9:14	1799	224	10	115	14
	9:15	9:29	1506	53	1	39	4
	9:30	9:44	1203	4	6	50	7
	9:45	9:59	1036	0	2	175	10
	10:00	10:14	1131	19	12	195	49
	10:15	10:29	1054	9	4	139	11
	10:30	10:44	960	0	2	69	6
	10:45	10:59	951	0	2	256	8
	11:00	11:14	1031	0	15	351	18
	11:15	11:29	1023	0	3	133	8
	11:30	11:44	902	0	1	125	6
	11:45	11:59	970	0	7	77	11
	12:00	12:14	869	0	3	262	10
	12:15	12:29	861	0	3	71	5
	12:30	12:44	812	0	6	163	22
	12:45	12:59	817	0	5	186	25
	13:00	13:14	826	0	3	73	5
	13:15	13:29	770	0	5	87	8
	13:30	13:44	744	0	8	146	15
	13:45	13:59	752	0	5	208	17
	14:00	14:14	722	0	10	134	23
	14:15	14:29	785	0	9	209	18
	14:30	14:44	724	0	6	302	42
	14:45	14:59	789	0	10	180	48
	15:00	15:14	1450	123	23	521	84

UTAH

January 1 – December 31, 2017

Date	Interval start/finish (Mountain Time)	Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds	Date
4/7/2017	15:15	15:29	1379	80	10	197	26
	15:30	15:44	878	0	2	238	13
	15:45	15:59	864	0	0	167	9
	16:00	16:14	852	0	5	131	9
	16:15	16:29	999	0	2	196	8
	16:30	16:44	1049	26	14	390	26
	16:45	16:59	1481	131	25	292	65
	17:00	17:14	1136	16	21	271	40
9/12/2017	12:30	12:44	1584	169	94	344	102
	12:45	12:59	834	0	15	183	75
	13:00	13:14	603	0	7	130	12
	13:15	13:29	509	0	7	176	32
11/7/2017	9:15	9:29	2392	307	337	521	115
	9:30	9:44	1672	393	22	217	57
	9:45	9:59	682	0	5	155	45
	10:00	10:14	684	0	23	284	80

Twenty First Century, an external Interactive Voice Response system, was utilized.

*   All customers attempting to reach PacifiCorp Network.

** When Twenty First Century is manually invoked, the AT&T Network returns a courtesy message to non-outage callers. This includes repeated attempts.

*** Longest time any customer waited.

2.13 Utah State Customer Guarantee Summary Status

customer*guarantees* January to December 2017
Utah

	Description	2017 Events	2017 Failures	2017 % Success	2017 Paid	2016 Events	2016 Failures	2016 % Success	2016 Paid
CG1	Restoring Supply	928,180	1	100.00%	$50	921,417	0	100.00%	$0
CG2	Appointments	10,064	10	99.90%	$500	9,090	11	99.88%	$550
CG3	Switching on Power	5,620	2	99.96%	$100	6,404	1	99.98%	$50
CG4	Estimates	1,394	7	99.50%	$350	1,348	3	99.78%	$150
CG5	Respond to Billing Inquiries	1,822	7	99.62%	$350	1,970	1	99.95%	$50
CG6	Respond to Meter Problems	917	1	99.89%	$50	982	1	99.90%	$50
CG7	Notification of Planned Interruptions	101,319	29	99.97%	$1,450	119,905	52	99.96%	$2,600
		1,049,316	**57**	**99.99%**	**$2,850**	**1,061,116**	**69**	**99.99%**	**$3,450**

Overall Customer Guarantee performance remains above 99%, demonstrating Rocky Mountain Power's continued commitment to customer satisfaction.
Major Events are excluded from the Customer Guarantees program. The program also defines certain exemptions, which are primarily for safety, access to outage site, and emergencies.

3 MAINTENANCE COMPLIANCE TO ANNUAL PLAN

3.1 T&D Preventive and Corrective Maintenance Programs

Preventive Maintenance

The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions[10], and perform appropriate preventive actions upon those facilities. Assessment of policies, including the costs and benefits of delivery of these policies, will result in modifications to them. Thus, local triggers that result in more frequent or more burdensome inspection and maintenance practices have resulted in refinement to some of these PM activities. As the Company continues this assessment, further variations of the policies will result in refinement to the maintenance plan.

Transmission and Distribution Lines

- Visual assurance inspections are designed to identify damage or defects that may endanger public safety or adversely affect the integrity of the electric system.
- Detailed inspections are in depth visual inspections of each structure and the spans between each structure or pad-mounted distribution equipment.[11]
- Pole testing includes a sound and bore to identify decay pockets that would compromise the wood pole's structural integrity.

Substations and Major Equipment

- Rocky Mountain Power inspects and maintains substations and associated equipment to ascertain all components within the substation are operating as expected. Abnormal conditions that are identified are prioritized for repair (corrective maintenance).
- Rocky Mountain Power has a condition based maintenance program for substation equipment including load tap changers, regulators, and transmission circuit breakers. Diagnostic testing is performed on a time based interval and the results are analyzed to determine if the equipment is suitable for service or maintenance tasks to be performed. Protection system and communication system maintenance is performed based on a time interval basis.

Corrective Maintenance

The primary focus of the corrective maintenance plan is to correct the abnormal conditions found during the preventive maintenance process.

Transmission and Distribution Lines

- Correctable conditions are identified through the preventive maintenance process.
- Outstanding conditions are recorded in a database and remain until corrected.

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[10] The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions, and perform appropriate preventive actions upon those facilities. Condition priorities are as follows:

Priority A: Conditions that pose a potential but not immediate hazard to the public or employees, or that risk loss of supply or damage to the electrical system.

Priority B: Conditions that are nonconforming, but that in the opinion of the inspector do not pose a hazard.

Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

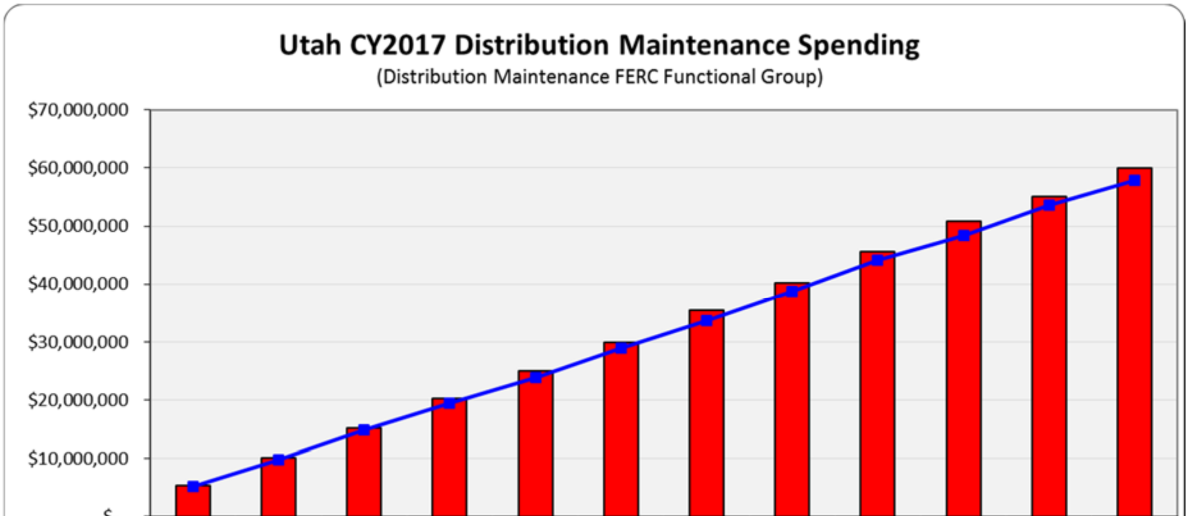
Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. Priority G: Conditions that conform to the regulations requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered" and are considered conforming.

[11] Effective 1/1/2007, Rocky Mountain Power modified its reliability & preventive planning methods to utilize repeated reliability events to prioritize localized preventive maintenance activities, using its Reliability Work Planning methodology. At this time, repeated outage events experienced by customers will result in localized inspection and correction activities, rather than being programmatically performed at either the entire circuit or map section level.

Substations and Major Equipment

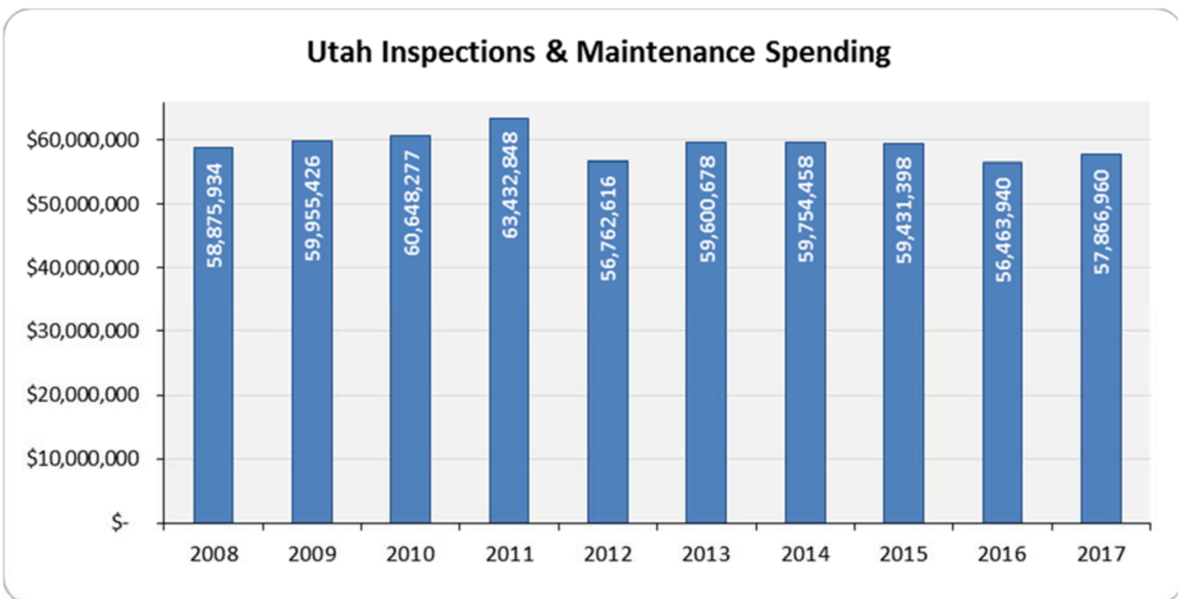
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending[12,13]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,330,966	$10,040,232	$15,110,483	$20,266,510	$25,040,861	$29,939,201	$35,389,728	$40,215,600	$45,587,509	$50,834,800	$55,077,301	$59,944,965
Actual	$5,140,822	$9,747,987	$14,893,833	$19,416,373	$23,906,970	$28,952,412	$33,634,968	$38,697,598	$44,161,773	$48,440,197	$53,633,313	$57,866,960

3.2.1 Maintenance Historical Spending



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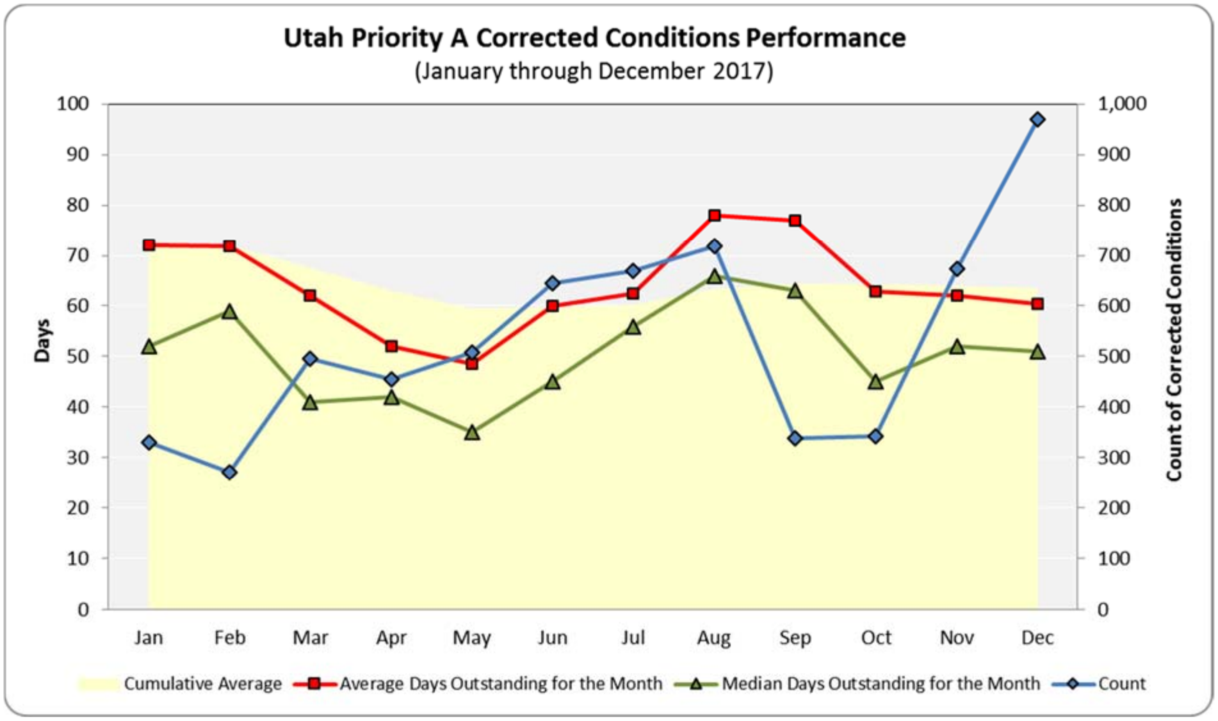
12 Maintenance spending reflected does not include Vegetation Management and Fault Locating costs, which when reporting under FERC accounting methodology, FERC has traditionally considered maintenance.

13 The Utah distribution maintenance total year plan of $63.8m is overstated by $6.4m due to a misplaced system allocated entry in the plan. The Utah distribution maintenance plan should be $57.4m. The overall PacifiCorp plan is correct as actual expenses for the misplaced plan item will be incurred in the correct department for which no plan exists.

3.3 Distribution Priority "A" Conditions Correction History

The Company reports history of A priority corrections. This reporting element dates back to Docket-04-035-070, which expired on December 31, 2011. In this commitment the Company was required to correct distribution A priority conditions on average within 120 days. After the commitment expired, stakeholders requested the Company continue to report the information, believing it to be a useful indicator of work delivered by the Company. As can be seen in the chart below, the company has consistently delivered the average age of priority A conditions well below the 120 day target.



3.3.1 Oldest Outstanding Priority A Conditions In Utah

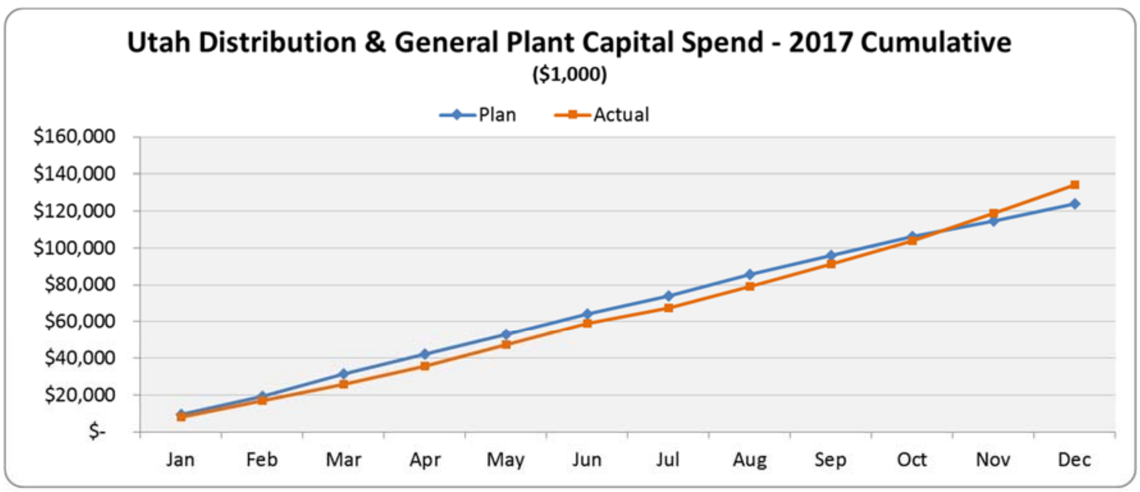
District	Map string / Plant Locality	Facility Point / Pole #	Condition	Inspection Remarks	Inspection Date	Completion Date	Days to Correct	Circuit	Explanation
Richfield	8210601	4	BOINSUL	LOOSE POLE TOP PIN 6432962	3/13/2017	1/2/2018	295	082106	Upon further inspection it was determined that the entire transmission structure needed to be changed and not just the insulator. The structure needed to be engineered and an outage window scheduled preparatory to the transmission line work being completed.
Price	11413009	369907	BOPOLE	DECAY REJECT RESTORE_ SRA	4/17/2017	2/2/2018	291	HPM1	Data transmission errors for the downloaded inspection findings resulted in delay receiving the conditions. The conditions were worked soon after they were estimated.
Price	11413010	314903	BOPOLE	DECAY REJECT RESTORE_ Rotten Butt	4/24/2017	2/5/2018	287	HPM1	
Richfield	82115	78	BOXARM	ARM IS SPLIT_ CHANGED TO B PRI PER BRUCE BLACKHAM	4/24/2017	1/11/2018	262	082115	This transmission structure is in the middle of an alfalfa field, so the customer didn't want the crews in the field during certain times of the year. An outage had to be delayed until after the crop was harvested. The outage was scheduled, but they discovered the substation breaker contained asbestos and needed to be replaced before the outage could be taken, so the outage had to be delayed until the substation work was complete.
Richfield	82115	78	BOINSUL	LEANING PIN DUE TO SPLIT XARM	4/24/2017	1/11/2018	262	082115	

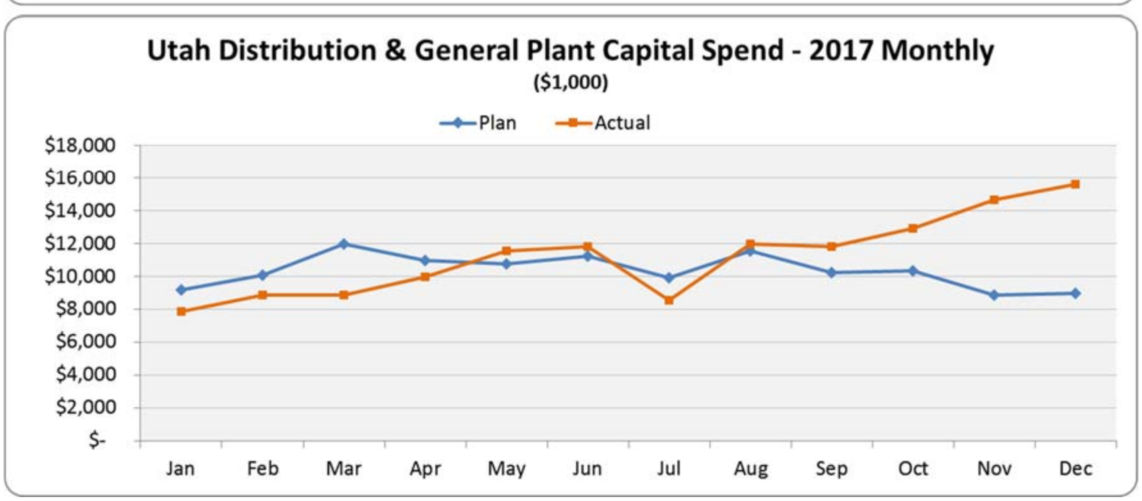
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January –December 2017

Investment		Actuals ($M)	Plan ($M)	Significant Variance Explanations
1.	Mandated	$10.4	$9.5	Mandated net metering over plan, (+$1.1M).
2.	New Connect	$47.3	$44.9	Residential and commercial new revenue connections over plan, (+$3.3M).
3.	System Reinforcement	$19.5	$16.4	Substation reinforcement over plan (+3.5M), partially offset by feeder reinforcement under plan (-$1.0M).
4.	Replacement	$48.7	$47.3	Replacements for vehicles (transport), tools, and underground cable over plan (+$4.8M), partially offset by replacements for microwave/fiber communications, overhead distribution lines, storm & casualty, and substation transformers under plan (-$3.2M).
5.	Upgrade & Modernize	$8.4	$5.7	Functional upgrade reliability over plan, (+$2.8M).
	Total	$134.3	$123.8	



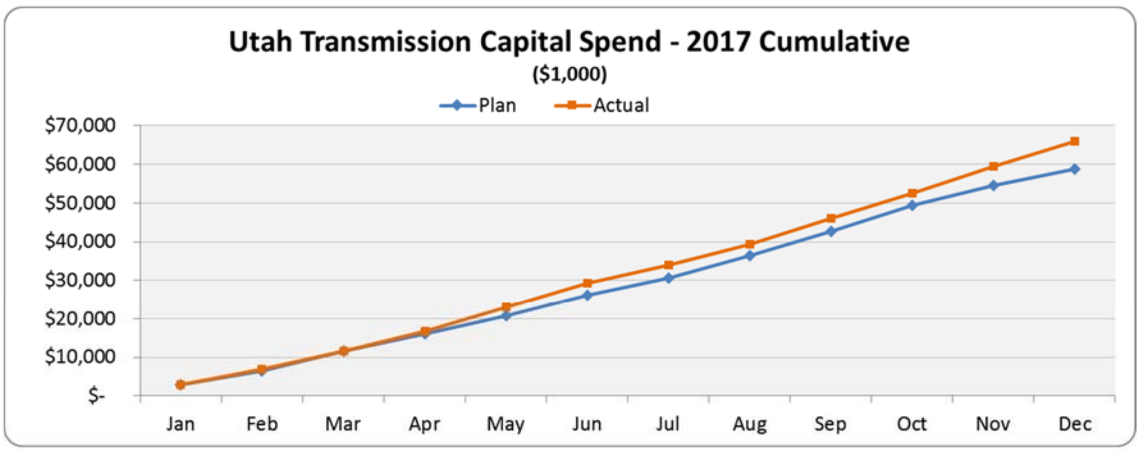


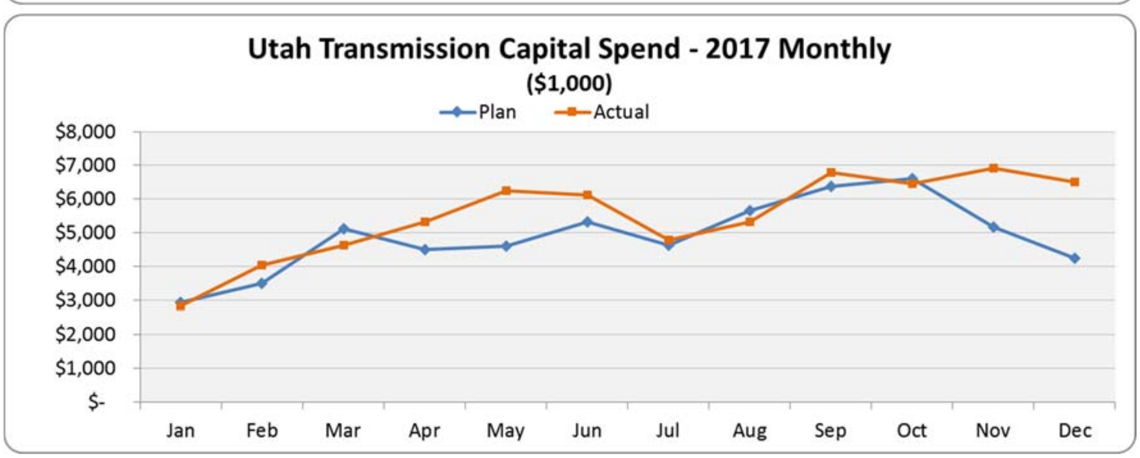
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January –December 2017

Investment		Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	$8.2	$7.0	Mandated environmental/avian protection over plan, (+$2.1M).
2.	New Connect	$0.0	$1.0	Industrial new revenue connections under plan, (-$0.9M).
3.	Local Trans-mission System Reinforcements	$13.9	$13.8	
**4.	Main Grid Reinforcements / Interconnections	$24.3	$21.6	Syracuse Second Transformer (-$1.1M), and Purgatory Flat New 138kV (-$1.9M) under plan, offset by OTP115 UAMPS Lehi City 6th POD (+$4.6M) completed outside of plan due to customer agreement not being signed until after budget plan submission.
**5.	Energy Gateway Transmission	$0.3	$1.4	Sigurd Red Butte Crystal 345kV Line (-$1.0M) under plan due to receiving settlement to resolve a claim against contractor.
6.	Replacement	$17.4	$13.3	Replacements for substation switchgear/breakers/reclosers, storm & casualty, and overhead transmission poles over plan, (+$5.2M), partially offset by replacements for substation transformers under plan, (-$1.4M).
7.	Upgrade & Modernize	$2.0	$0.5	Functional upgrade reliability over plan, (+0.8M).
	Total	$66.0	$58.7	





* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values. ** Main Grid Reinforcement/Interconnections and Energy Gateway Transmission values include a small amount of General Plant $ for communications work.

4.3 New Connects

	2016	2017												
	YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**YEAR**
Residential														
UT South	923	54	47	77	80	122	118	63	94	119	105	62	64	1,005
UT North/Metro	4,804	414	307	804	337	453	615	190	369	377	419	775	784	5,844
UT Central	9,542	966	732	848	846	890	748	661	1,014	846	1,305	811	787	10,454
Total Residential	**15,269**	**1,434**	**1,086**	**1,729**	**1,263**	**1,465**	**1,481**	**914**	**1,477**	**1,342**	**1,829**	**1,648**	**1,635**	**17,303**
Commercial														
UT South	267	10	21	12	7	18	30	15	18	21	22	25	11	210
UT North/Metro	676	58	57	42	69	73	60	58	66	79	68	78	77	785
UT Central	814	56	56	47	52	59	98	56	82	74	91	89	86	846
Total Commercial	**1,757**	**124**	**134**	**101**	**128**	**150**	**188**	**129**	**166**	**174**	**181**	**192**	**174**	**1,841**
Industrial														
UT South	1	0	0	0	0	0	0	0	2	0	0	0	0	2
UT North/Metro	2	1	1	0	0	0	1	0	0	0	0	0	0	3
UT Central	3	0	0	0	0	0	0	0	0	4	0	1	0	5
Total Industrial	**6**	**1**	**1**	**0**	**0**	**0**	**1**	**0**	**2**	**4**	**0**	**1**	**0**	**10**
Irrigation														
UT South	58	0	1	4	7	11	4	1	4	0	1	1	3	37
UT North/Metro	5	1	0	0	1	0	1	0	2	0	0	0	0	5
UT Central	8	0	0	0	2	1	5	0	0	1	0	0	0	9
Total Irrigation	**71**	**1**	**1**	**4**	**10**	**12**	**10**	**1**	**6**	**1**	**1**	**1**	**3**	**51**
TOTAL New Connects														
UT South	1,249	64	69	93	94	151	152	79	118	140	128	88	78	1,254
UT North/Metro	5,487	474	365	846	407	526	677	248	437	456	487	853	861	6,637
UT Central	10,367	1,022	788	895	900	950	851	717	1,096	925	1,396	901	873	11,314
TOTAL New Connects	**17,103**	**1,560**	**1,222**	**1,834**	**1,401**	**1,627**	**1,680**	**1,044**	**1,651**	**1,521**	**2,011**	**1,842**	**1,812**	**19,205**

Utah South region includes Moab, Price, Cedar City and Richfield
Utah North/Metro region includes SLC Metro, Ogden and Layton
Utah Central region included American Fork, Vernal, Toole, Jordan Valley and Park City
Region areas a subject to change for operational purposes and may differ from historical reporting.
Smithfield and Laketown are excluded because the report was developed using an old coding system that included them under ID/ WY WEST and not Utah.
Temporary connections used to be included in our reports because there is no coding involved and, therefore, was no way to accurately remove them. They did not double count new connections because when a permanent connection was established the temporary went away. In 2015 it was decided by our regulation department that we must code all temporary connections as Commercial to be able to apply the commercial billing rates to the contractors who would be using the electricity until a homeowner is in place. As there are quite a lot of residential customers and a much smaller proportion of commercial customers, this skewed the volumes considerably and made historic trend comparison useless. We have, therefore, done what we can, to eliminate temporary connections from our reporting since that time.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH

Tree Program Reporting

January 1, 2017 through December 31, 2017

Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2017-12/31/2017 Miles Planned	1/1/2017-12/31/2017 Actual Miles	01/01/2017-12/31/2017 Ahead/ Behind	1/1/2017-12/31/2017 % Ahead/ Behind	1/1/2017-12/31/2019 Miles Planned	1/1/2017-12/31/2019 Actual Miles	01/01/2017-12/31/2019 Ahead/ Behind	1/1/2017-12/31/2019 % Ahead/ Behind
	column a	*column b*	*column c*	*column d*	*column e*	*column f*	*column g*	*column h*	*column i*
UTAH	11,009	3,454	3,806	352	110%	3,454	3,806	352	110%
AMERICAN FORK	824	173	173	0	100%	173	173	0	100%
CEDAR CITY	1,373	657	688	31	105%	657	688	31	105%
JORDAN VALLEY	769	345	366	21	106%	345	366	21	106%
LAYTON	284	61	25	-36	41%	61	25	-36	41%
MOAB	976	183	183	0	100%	183	183	0	100%
OGDEN	885	83	300	217	361%	83	300	217	361%
PARK CITY	538	222	222	0	100%	222	222	0	100%
PRICE	589	288	321	33	111%	288	321	33	111%
RICHFIELD	1,340	155	155	0	100%	155	155	0	100%
SL METRO	1,206	478	592	114	124%	478	592	114	124%
SMITHFIELD	762	216	276	60	128%	216	276	60	128%
TOOELE	481	92	92	0	100%	92	92	0	100%
TREMONTON	732	417	329	-88	79%	417	329	-88	79%
VERNAL	250	84	84	0	100%	84	84	0	100%

Distribution cycle $/tree:	$114.43
Distribution cycle $/mile:	$2,501
Distribution cycle removal %	19%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles ahead/behind Schedule	Miles on Schedule	% of miles on/behind Schedule
6,629	429	803	374	7,003	106%

Transmission $/mile: $3,296

Current distribution cycle began January 1, 2017 and extends until December 31, 2019.

Notes:

Column a: Total overhead distribution pole miles by district

Column b: Total overhead distribution pole miles planned for the period January 1, 2017 through December 31, 2017

Column c: Actual overhead distribution pole miles worked during the period January, 2017 through December 31,2017

Column d: Miles ahead or behind for the period January 1, 2017 through December 31, 2017 (column c-column b)

Column e: Percent of actual compared to planned for the period January 1, 2017 through December 31,2017 ((column c÷b)×100)

Column f: Total overhead distribution pole miles planned for the period January 1, 2017 through December 31, 2019

Column g: Actual overhead distribution pole miles worked during the period January 1 2017 through December 31, 2019

Column h: Miles ahead or behind for the period January 1, 2017 through December 31, 2019 (column g-column f)

Column i: Percent of actual compared to planned for the period January 1, 2017 through December 31, 2019 ((column g÷f)×100). Max = 100%

5.2 Budget

UTAH

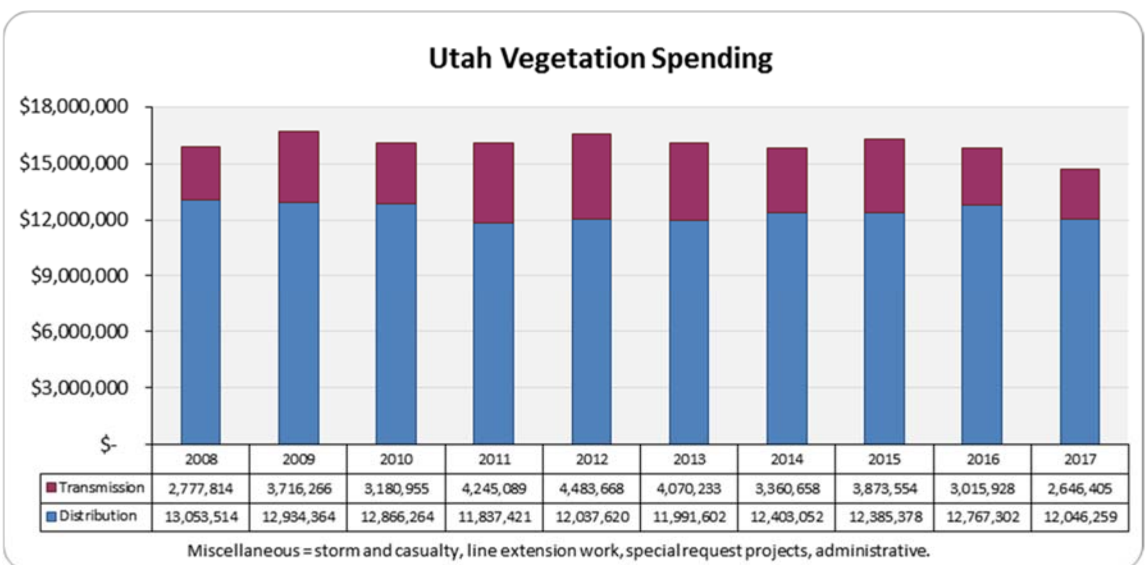
Tree Program Reporting

	CY2018	CY2019	CY2020
Distribution	$10,550,000	$10,550,000	$10,550,000
Transmission	$2,840,000	$2,840,000	$2,840,000
Total Tree Budget	**$13,390,000**	**$13,390,000**	**$13,390,000**

Calendar year 2017	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$572,296	$950,000	-$377,704	$96,589	$313,333	-$216,744
Feb	$1,297,670	$950,000	$347,670	$127,197	$313,333	-$186,136
Mar	$878,938	$950,000	-$71,062	$105,171	$313,333	-$208,163
Apr	$942,334	$950,000	-$7,666	$62,453	$313,333	-$250,881
May	$880,929	$950,000	-$69,071	$104,137	$313,333	-$209,197
Jun	$1,011,010	$950,000	$61,010	$250,830	$313,333	-$62,503
Jul	$770,546	$950,000	-$179,454	$167,852	$313,333	-$145,482
Aug	$913,918	$950,000	-$36,082	$503,890	$313,333	$190,557
Sep	$767,962	$950,000	-$182,038	$269,706	$313,333	-$43,627
Oct	$1,389,834	$950,000	$439,834	$249,226	$313,333	-$64,107
Nov	$1,537,334	$950,000	$587,334	$310,437	$313,333	-$2,896
Dec	$1,083,487	$950,000	$133,487	$398,917	$313,333	$85,584
Total	**$12,046,259**	**$11,400,000**	**$646,259**	**$2,646,405**	**$3,760,000**	**-$1,113,595**

Average # Tree Crews on Property (YTD) **48**

5.2.1 Vegetation Historical Spending



6 Appendix

6.1 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[14] Standard for Reliability Indices.

Sustained Outage
A sustained outage is defined as an outage of greater than 5 minutes in duration.

Momentary Outage Event
A momentary outage is defined as an outage equal to or less than 5 minutes in duration. Rocky Mountain Power has historically captured this data using substation breaker fault counts, but where SCADA (Supervisory Control and Data Acquisition Systems) exist, uses this data to calculate consistent with IEEE 1366-2003.

Reliability Indices

SAIDI
SAIDI (system average interruption duration index) is an industry-defined term to define the average duration summed for all sustained outages a customer experiences in a given period. It is calculated by summing all customer minutes lost for sustained outages (those exceeding 5 minutes) and dividing by all customers served within the study area. When not explicitly stated otherwise, this value can be assumed to be for a one-year period.

Daily SAIDI
In order to evaluate trends during a year and to establish Major Event Thresholds, a daily SAIDI value is often used as a measure. This concept was introduced in IEEE Standard 1366-2003. This is the day's total customer minutes out of service divided by the static customer count for the year. It is the total average outage duration customers experienced for that given day. When these daily values are accumulated through the year, it yields the year's SAIDI results.

SAIFI
SAIFI (system average interruption frequency index) is an industry-defined term that attempts to identify the frequency of all sustained outages that the average customer experiences during a given time-frame. It is calculated by summing all customer interruptions for sustained outages (those exceeding 5 minutes in duration) and dividing by all customers served within the study area.

CAIDI
CAIDI (customer average interruption duration index) is an industry-defined term that is the result of dividing the duration of the average customer's sustained outages by the frequency of outages for that average customer. While the Company did not originally specify this metric under the umbrella of the Performance Standards Program within the context of the Service Standards Commitments, it has since been determined to be valuable for reporting purposes. It is derived by dividing PS1 (SAIDI) by PS2 (SAIFI).

[14] IEEE 1366-2003 was adopted by the IEEE on December 23, 2003. It was subsequently modified in IEEE 1366-2012, but all definitions used in this document are consistent between these two versions. The definitions and methodology detailed therein are now industry standards. Later, in Docket No. 04-035-T13 the Utah Public Utilities Commission adopted the standard methodology for determining major event threshold.

MAIFI$_E$

MAIFI$_E$ (momentary average interruption event frequency index) is an industry-defined term that attempts to identify the frequency of all momentary interruption events that the average customer experiences during a given time-frame. It is calculated by counting all momentary operations which occur within a 5 minute time period, as long as the sequence did not result in a device experiencing a sustained interruption. This series of actions typically occurs when the system is trying to re-establish energy flow after a faulted condition, and is associated with circuit breakers or other automatic reclosing devices.

Lockout

Lockout is the state of device when it attempts to re-establish energy flow after a faulted condition but is unable to do so; it systematically opens to de-energize the facilities downstream of the device then recloses until a lockout operation occurs. The device then requires manual intervention to re-energize downstream facilities. This is generally associated with substation circuit breakers and is one of the variables used in the Company's calculation of blended metrics.

CEMI

CEMI is an acronym for Customers Experiencing Multiple (Momentary Event and Sustained) Interruptions. This index depicts repetition of outages across the period being reported and can be an indicator of recent portions of the system that have experienced reliability challenges.

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 or 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
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

CPI05

CPI05 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. Unlike CPI99, it includes Major Event and Loss of Supply or Transmission outages. The calculation of CPI05 uses the same weighting and normalizing factors as CPI99.

Performance Types

Rocky Mountain Power recognizes several categories of performance; major events and underlying performance. Underlying performance days may be significant event days. Outages recorded during any day may be classified as "controllable" events.

Major Events

A Major Event (ME) is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology. The values used for the reporting period and the prospective period are shown below.

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2017	897,258	5.74	5,152,204
1/1-12/31/2018	917,739	5.41	4,969,384

Significant Events

The Company has evaluated its year-to-year performance and as part of an industry weather normalization task force, sponsored by the IEEE Distribution Reliability Working Group, determined that when the Company recorded a day in excess of 1.75 beta (or 1.75 times the natural log standard deviation beyond the natural log daily average for the day's SAIDI) that generally these days' events are generally associated with weather events and serve as an indicator of a day which accrues substantial reliability metrics, adding to the cumulative reliability results for the period. As a result, the Company individually identifies these days so that year-on-year comparisons are informed by the quantity and their combined impact to the reporting period results.

Underlying Events

Within the industry, there has been a great need to develop methodologies to evaluate year-on-year performance. This has led to the development of methods for segregating outlier days, via the approaches described above. Those days which fall below the statistically derived threshold represent "underlying" performance, and are valid. If any changes have occurred in outage reporting processes, those impacts need to be considered when making comparisons. Underlying events include all sustained interruptions, whether of a controllable or non-controllable cause, exclusive of major events, prearranged (which can include short notice emergency prearranged outages), customer requested interruptions and forced outages mandated by public authority typically regarding safety in an emergency situation.

Controllable Distribution (CD) Events

In 2008, the Company identified the benefit of separating its tracking of outage causes into those that can be classified as "controllable" (and thereby reduced through preventive work) from those that are "non-controllable" (and thus cannot be mitigated through engineering programs); they will generally be referred to in subsequent text as controllable distribution (CD). For example, outages caused by deteriorated equipment or animal interference are classified as controllable distribution since the Company can take preventive measures with a high probability to avoid future recurrences; while vehicle interference or weather events are largely out of the Company's control and generally not avoidable through engineering programs. (It should be noted that Controllable Events is a subset of Underlying Events. The *Cause Code Analysis* section of this report contains two tables for Controllable Distribution and Non-controllable Distribution, which list the Company's performance by direct cause under each classification.) At the time that the Company established the determination of controllable and non-controllable distribution it undertook significant root cause analysis of each cause type and its proper categorization (either controllable or non-controllable). Thus, when outages are completed and evaluated, and if the outage cause designation is improperly identified as non-controllable, then it would result in correction to the outage's cause to preserve the association between controllable and non-controllable based on the outage cause code. The company distinguishes the performance delivered using this differentiation for comparing year to date performance against underlying and total performance metrics.