ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

May 1, 2019

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. 19-035-19 –** 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, PacifiCorp d.b.a. Rocky Mountain Power ("Company") submits the Service Quality Review Report for the period January through December, 2018.

The Company recognizes that environmental impacts, such as wildland fires, can result in reduced reliability. As discussed in the technical conference that was held on January 8, 2019 in Docket No. 18-035-17, over the past several years the Company has been heavily engaged in fire mitigation planning in California and has recently evaluated the fire risks across its entire service territory and identified areas for which risks may be higher, which could lead to de-energized electrical equipment to minimize the consequences of wildland fire. At the technical conference, the Company agreed to provide an update regarding its assessment of proactive de-energization in its next service quality review report and possibly request an additional technical conference. The Company continues to assess a possible proactive de-energization program. At this time, the Company believes that an additional technical conference in the near future is premature. Once the timing is more certain, the Company will file a request in this docket for a technical conference.

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, Regulation

Enclosures

UTAH SERVICE QUALITY REVIEW

January 1 – December 31, 2018
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.

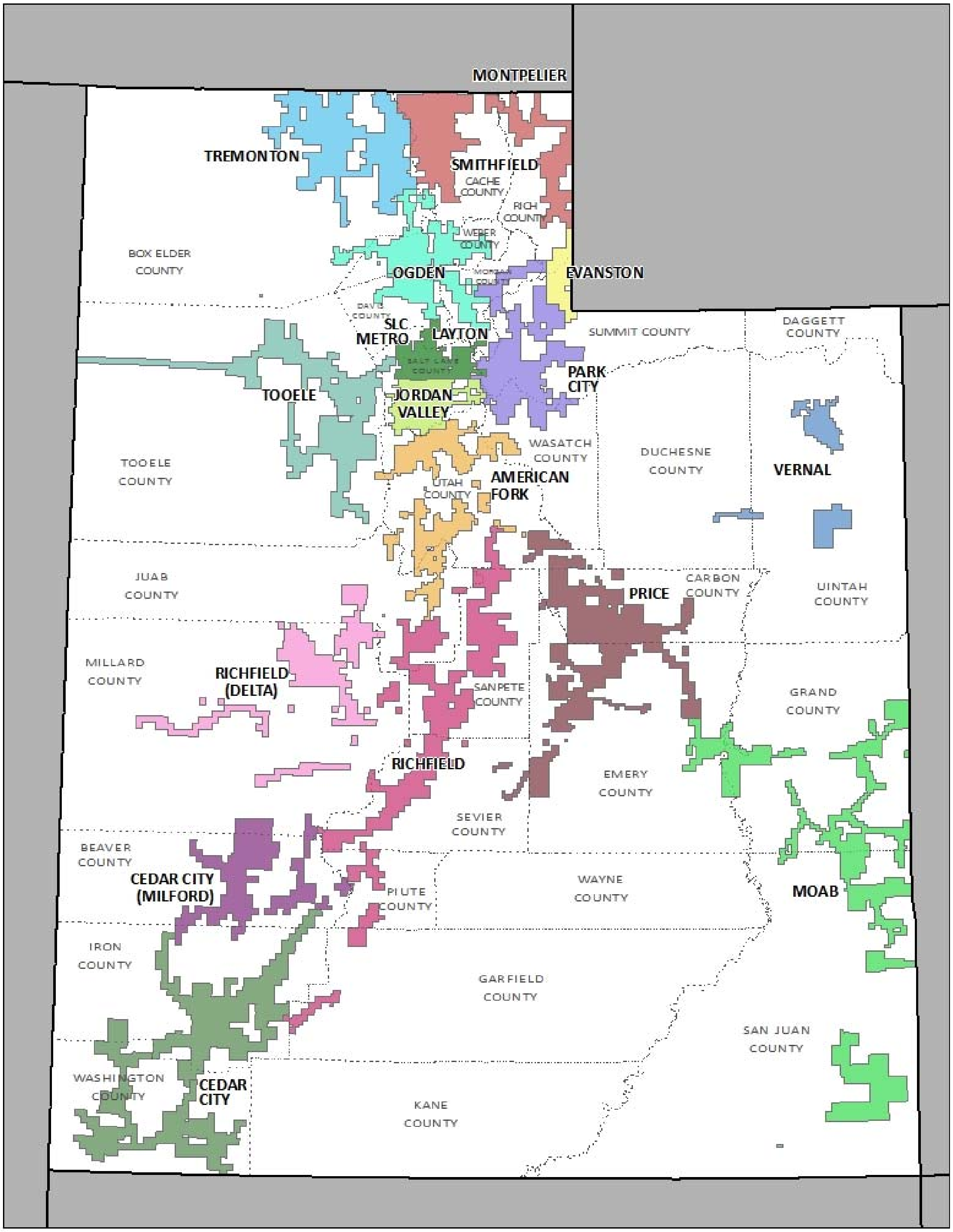
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

[2] On December 20, 2016, the Public Service Commission of Utah approved modified electric service reliability performance baseline notification levels of 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 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. Cause code information, which is reported consistently with past Service Quality Review Reports, is shown in Section 2.5. Baselines are discussed in Section 2.6. Finally, Section 2.7 contains reporting information complies with features outlined in Utah Title 746.313.

During the reporting period, there were no major events[4] while seven significant event days[5] were recorded.

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 year seven significant event days were recorded, which account for 21.4 SAIDI minutes, or about 17% of the reporting period's underlying 124 SAIDI minutes. These significant events were triggered by weather and loss of supply outages.

Significant Event Days					
Dates	**Cause: General Description**	**SAIDI**	**SAIFI**	**% Underlying SAIDI**	**% Underlying SAIFI**
February 19, 2018	Snow Storm and Pole Fires in Salt Lake City	2.8	0.017	5%	3%
March 22, 2018	Loss of Substation in Ogden	2.8	0.020	5%	4%
April 9, 2018	Loss of Transmission in Jordan Valley	3.1	0.058	5%	11%
April 16, 2018	Wind Storm in Salt Lake City and Jordan Valley	2.9	0.023	5%	4%
July 21, 2018	Wind Storm in Salt Lake City and Jordan Valley	2.3	0.010	2%	1%
August 19, 2018	Loss of Substation in Jordan Valley	5.1	0.017	4%	2%
October 2, 2018	Storm caused tree and pole fire outages in the Salt Lake City Region	2.4	0.017	2%	2%
	TOTAL	21.4	0.162	17%	15%

[4] Major event threshold shown below:

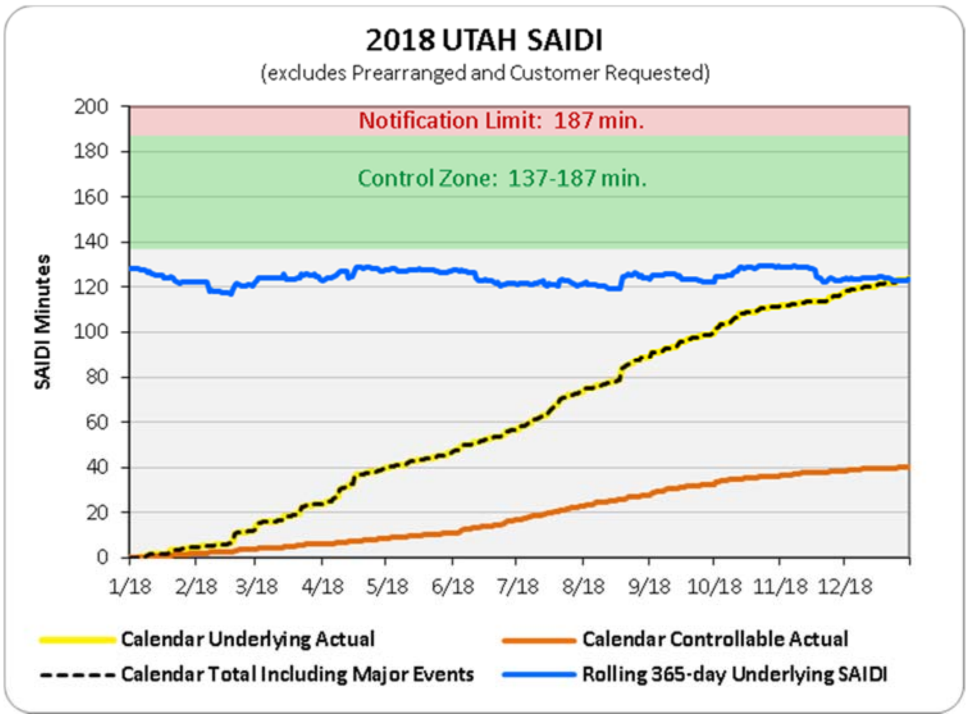
Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2018	917,739	5.41	4,969,384

[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).

2.1 System Average Interruption Duration Index (SAIDI)

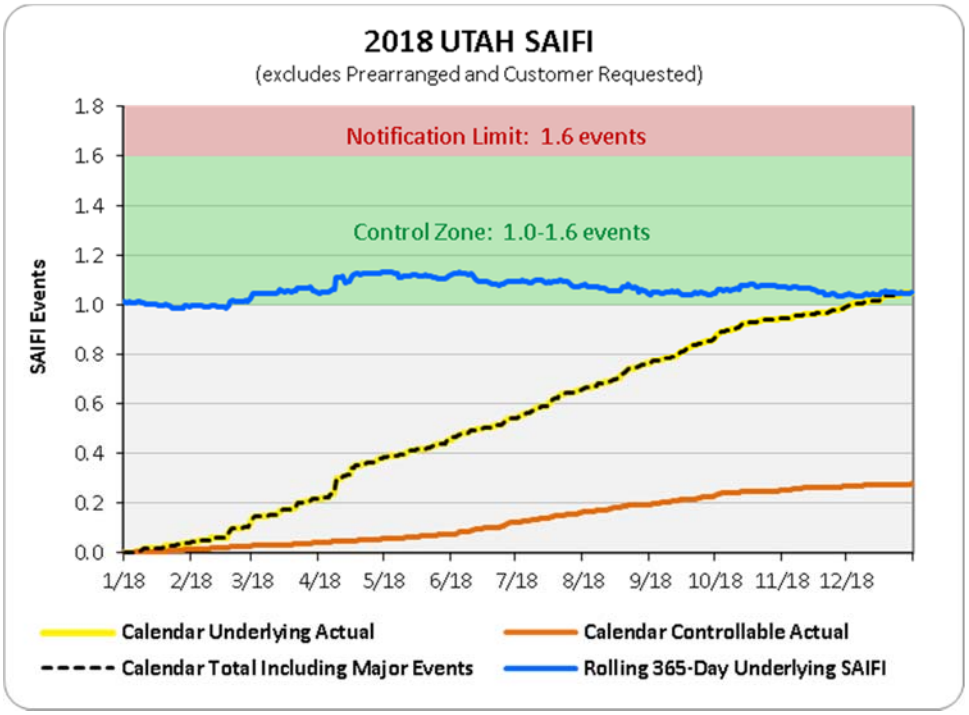
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below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

SAIDI	Reporting Period
Total	124
Underlying	124
Controllable Distribution	40



2.2 System Average Interruption Frequency Index (SAIFI)

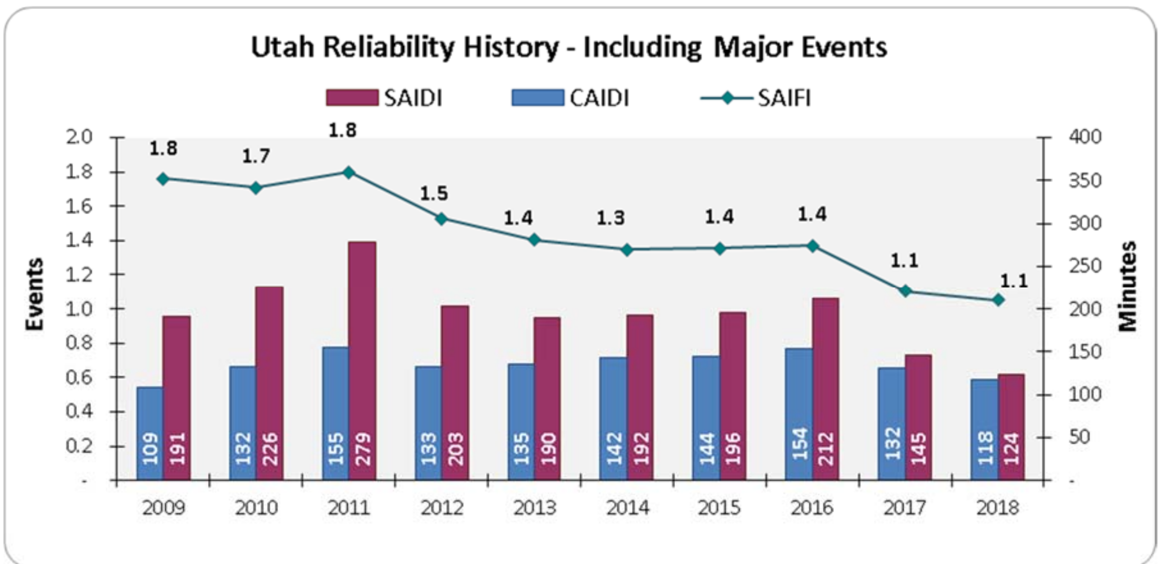
SAIFI	Reporting Period
Total	1.052
Underlying	1.052
Controllable Distribution	0.278

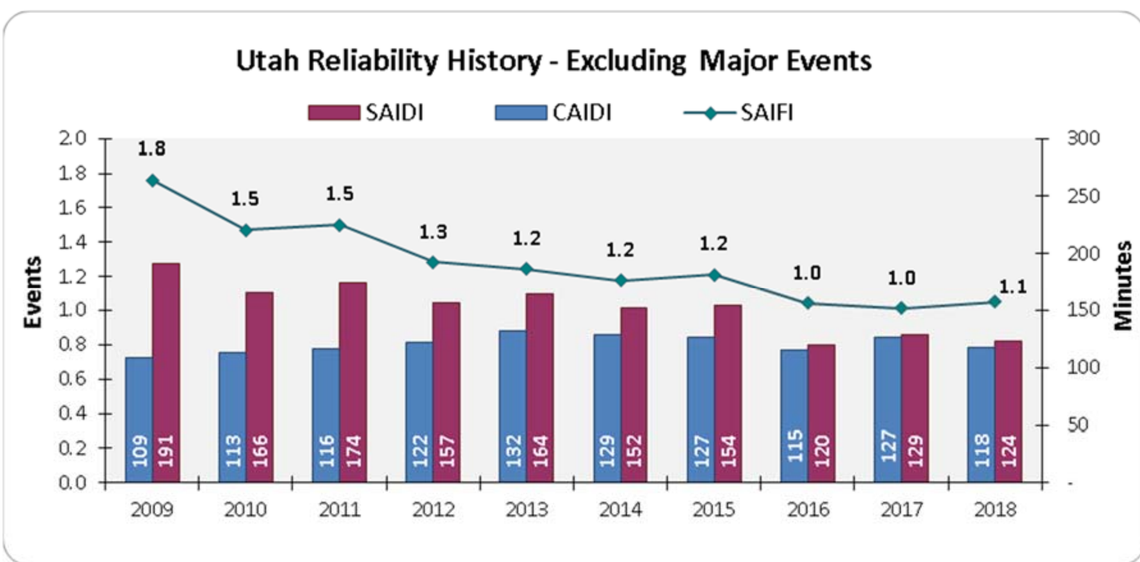


2.3 Reliability History

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.

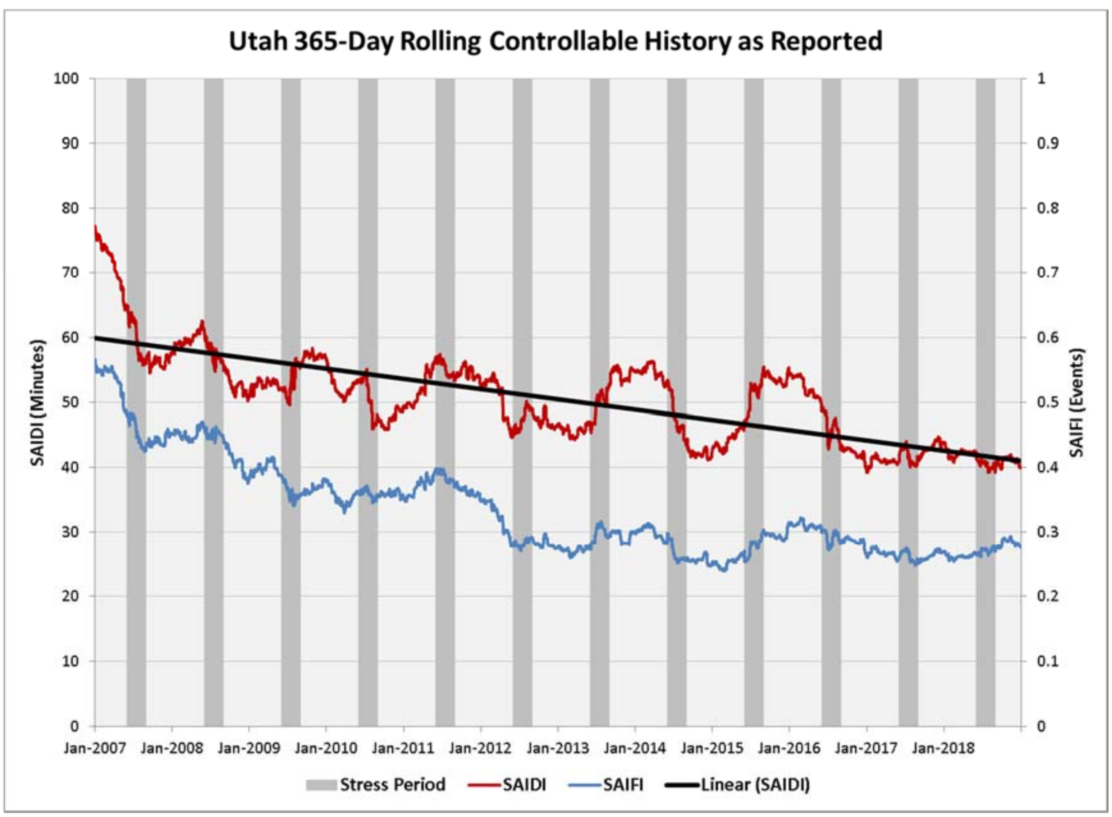


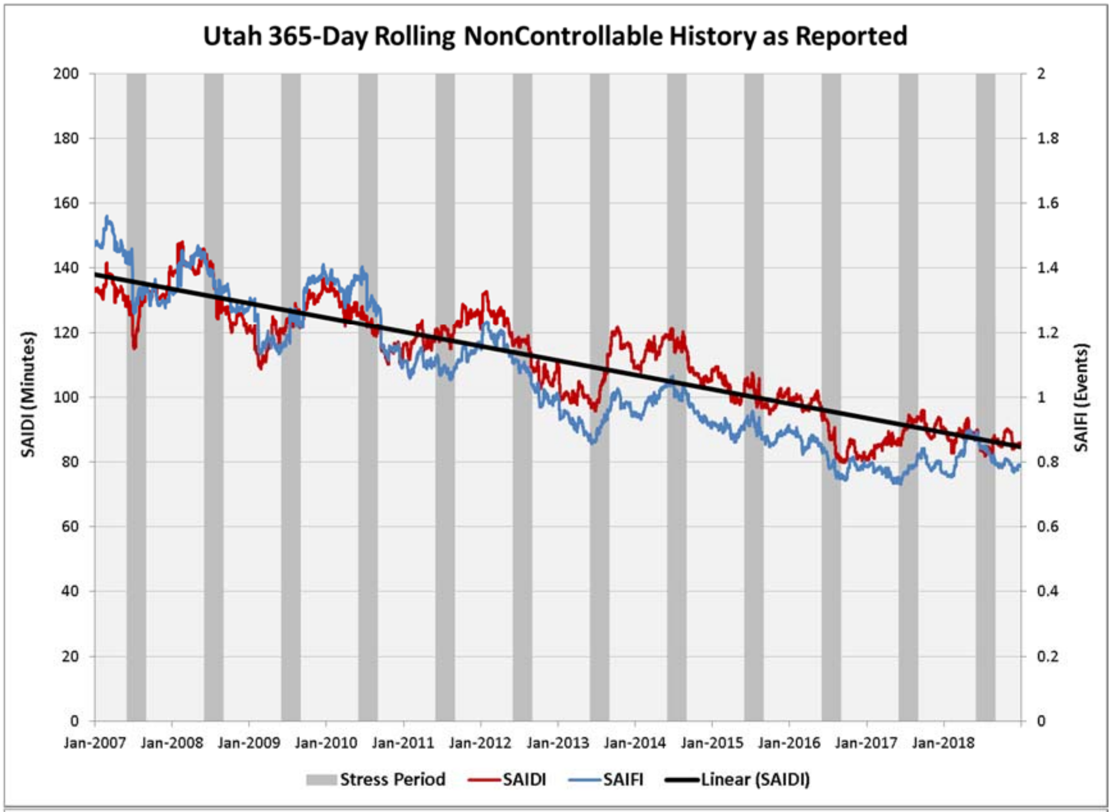


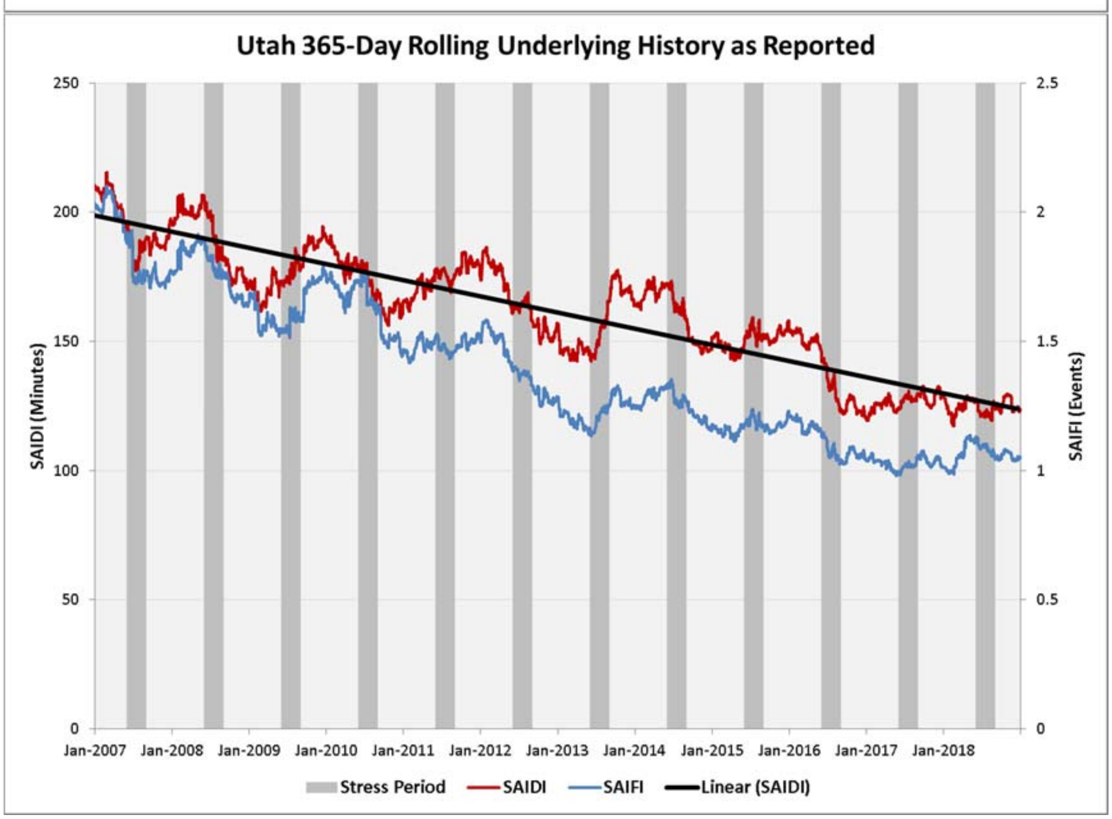
2.4 Controllable, Non-Controllable and Underlying Performance Review

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. As an example, animal-caused or 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. 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.




Utah 365-Day Rolling NonControllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
200
180
160
140
120
100
80
60
40
20
0
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Stress Period
SAIDI
SAIFI
Linear (SAIDI)


Utah 365-Day Rolling Underlying History as Reported
SAIDI (Minutes)
SAIFI (Events)
250
200
150
100
50
0
2.5
2
1.5
1
0.5
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

2.5 Cause Code Analysis

The tables below outline categories used in outage data collection. Subsequent charts and table use these groupings to develop patterns for outage performance.

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

2.5.1 Underlying 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.

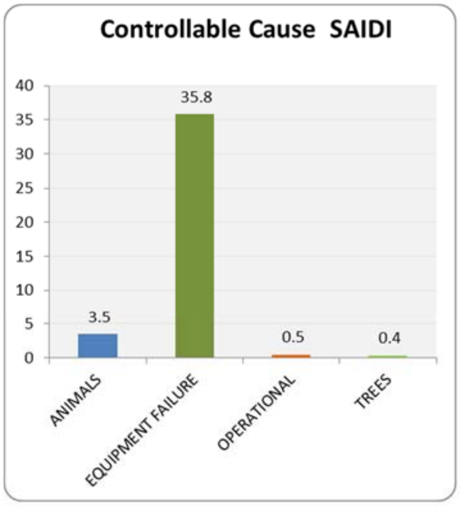
The cause analysis tables below detail SAIDI[6] and SAIFI by direct cause, with separate tables for the company's Controllable metrics and its Underlying metrics. (Both tables exclude major events.) Following the detail tables are pie charts showing the percentages attributed to each cause category with respect to three measures: total incidents, total customer minutes lost and total sustained customer interruptions, again with separate pie charts for Controllable and Underlying.

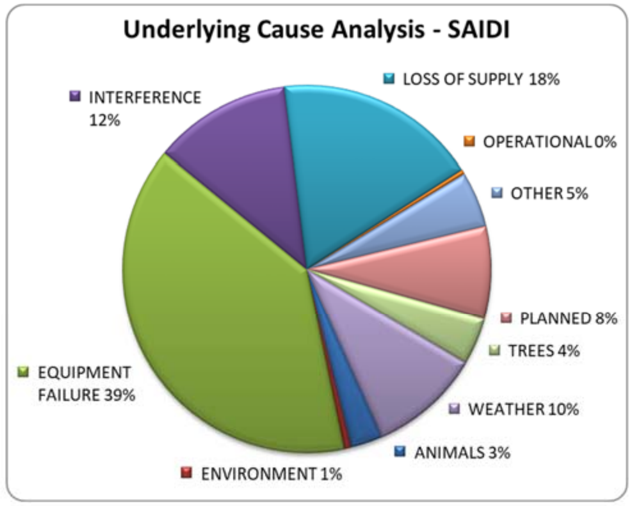
Note that the Underlying cause analysis table includes prearranged outages (*Customer Requested, Customer Notice Given, and Planned Notice Exempt* line items) with subtotals for their inclusion, while the grand totals in the table exclude these prearranged outages so that grand totals align with reported 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.

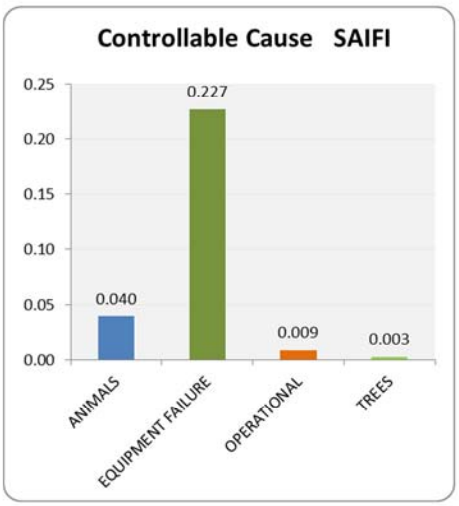
Utah Cause Analysis - Controllable 1/1/2018 - 12/31/2018					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	1,188,755	12,819	612	1.30	0.014
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,087,885	14,129	306	1.19	0.015
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	488,039	6,551	55	0.53	0.007
BIRD NEST (BMTS)	46,474	187	29	0.05	0.000
BIRD SUSPECTED, NO MORTALITY	358,492	2,567	122	0.39	0.003
ANIMALS	**3,169,646**	**36,253**	**1,124**	**3.45**	**0.040**
B/O EQUIPMENT	3,578,230	38,234	557	3.90	0.042
DETERIORATION OR ROTTING	28,496,287	159,255	4,296	31.05	0.174
OVERLOAD	754,617	10,783	102	0.82	0.012
RELAYS, BREAKERS, SWITCHES	67	1	9	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	6,585	17	33	0.01	0.000
EQUIPMENT FAILURE	**32,835,786**	**208,290**	**4,997**	**35.78**	**0.227**
FAULTY INSTALL	81,918	517	29	0.09	0.001
IMPROPER PROTECTIVE COORDINATION	97,028	919	17	0.11	0.001
INCORRECT RECORDS	20,026	932	19	0.02	0.001
INTERNAL CONTRACTOR	142,779	2,557	12	0.16	0.003
INTERNAL TREE CONTRACTOR	1,542	9	1	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	74,772	2,226	27	0.08	0.002
SWITCHING ERROR	23,163	733	1	0.03	0.001
OPERATIONAL	**441,227**	**7,893**	**106**	**0.48**	**0.009**
TREE - TRIMMABLE	328,183	2,580	90	0.36	0.003
TREES	**328,183**	**2,580**	**90**	**0.36**	**0.003**
Utah Including Prearranged	**36,774,842**	**255,016**	**6,317**	**40.07**	**0.278**

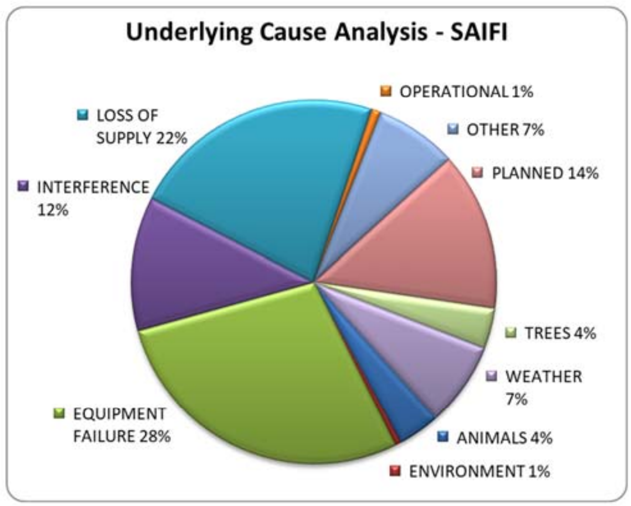
[6] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 917,739 (2018 Utah frozen customer count).

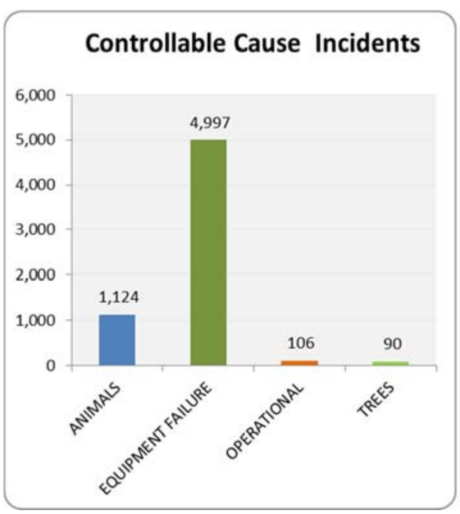
Utah Cause Analysis - Underlying 1/1/2018 - 12/31/2018					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	1,188,755	12,819	612	1.30	0.014
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,087,885	14,129	306	1.19	0.015
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	488,039	6,551	55	0.53	0.007
BIRD NEST (BMTS)	46,474	187	29	0.05	0.000
BIRD SUSPECTED, NO MORTALITY	358,492	2,567	122	0.39	0.003
ANIMALS	**3,169,646**	**36,253**	**1,124**	**3.45**	**0.040**
CONDENSATION / MOISTURE	39,198	176	6	0.04	0.000
CONTAMINATION	11,431	47	2	0.01	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	646,119	5,142	36	0.70	0.006
ENVIRONMENT	**696,748**	**5,365**	**44**	**0.76**	**0.006**
B/O EQUIPMENT	3,578,230	38,234	557	3.90	0.042
DETERIORATION OR ROTTING	28,496,287	159,255	4,296	31.05	0.174
NEARBY FAULT	228,590	1,876	7	0.25	0.002
OVERLOAD	754,617	10,783	102	0.82	0.012
POLE FIRE	11,406,606	60,408	263	12.43	0.066
RELAYS, BREAKERS, SWITCHES	67	1	9	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	6,585	17	33	0.01	0.000
EQUIPMENT FAILURE	**44,470,982**	**270,574**	**5,267**	**48.46**	**0.295**
DIG-IN (NON-PACIFICORP PERSONNEL)	4,811,286	34,149	356	5.24	0.037
OTHER INTERFERING OBJECT	1,154,180	21,028	101	1.26	0.023
OTHER UTILITY/CONTRACTOR	194,223	2,004	73	0.21	0.002
VANDALISM OR THEFT	176,755	495	18	0.19	0.001
VEHICLE ACCIDENT	7,409,153	57,340	283	8.07	0.062
INTERFERENCE	**13,745,597**	**115,016**	**831**	**14.98**	**0.125**
FAILURE ON OTHER LINE OR STATION	9	1	4	0.00	0.000
LOSS OF FEED FROM SUPPLIER	36,694	1,106	7	0.04	0.001
LOSS OF SUBSTATION	8,224,325	56,170	55	8.96	0.061
LOSS OF TRANSMISSION LINE	12,039,110	160,232	309	13.12	0.175
SYSTEM PROTECTION	5,420	4	3	0.01	0.000
LOSS OF SUPPLY	**20,305,557**	**217,513**	**378**	**22.13**	**0.237**
FAULTY INSTALL	81,918	517	29	0.09	0.001
IMPROPER PROTECTIVE COORDINATION	97,028	919	17	0.11	0.001
INCORRECT RECORDS	20,026	932	19	0.02	0.001
INTERNAL CONTRACTOR	142,779	2,557	12	0.16	0.003
INTERNAL TREE CONTRACTOR	1,542	9	1	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	74,772	2,226	27	0.08	0.002
SWITCHING ERROR	23,163	733	1	0.03	0.001
UNSAFE SITUATION	446	2	2	0.00	0.000
OPERATIONAL	**441,673**	**7,895**	**108**	**0.48**	**0.009**
OTHER, KNOWN CAUSE	415,850	13,260	120	0.45	0.014
UNKNOWN	5,167,593	57,108	1,000	5.63	0.062
OTHER	**5,583,443**	**70,368**	**1,120**	**6.08**	**0.077**
CONSTRUCTION	387,779	4,921	127	0.42	0.005
CUSTOMER NOTICE GIVEN	29,594,749	151,031	3,241	32.25	0.165
CUSTOMER REQUESTED	589,325	4,896	40	0.64	0.005
EMERGENCY DAMAGE REPAIR	8,099,493	118,928	951	8.83	0.130
INTENTIONAL TO CLEAR TROUBLE	671,169	11,524	49	0.73	0.013
PLANNED NOTICE EXEMPT	2,087,181	15,602	270	2.27	0.017
TRANSMISSION REQUESTED	72,065	220	7	0.08	0.000
PLANNED	**41,501,761**	**307,122**	**4,685**	**45.22**	**0.335**
TREE - NON-PREVENTABLE	4,387,487	32,066	462	4.78	0.035
TREE - TRIMMABLE	328,183	2,580	90	0.36	0.003
TREES	**4,715,670**	**34,646**	**552**	**5.14**	**0.038**
ICE	1,264	15	6	0.00	0.000
LIGHTNING	2,739,377	20,237	298	2.98	0.022
SNOW, SLEET AND BLIZZARD	1,753,610	10,531	139	1.91	0.011
WIND	6,650,791	41,027	427	7.25	0.045
WEATHER	**11,145,041**	**71,810**	**870**	**12.14**	**0.078**
Utah Including Prearranged	**145,776,118**	**1,136,562**	**14,979**	**158.84**	**1.238**
Utah Excluding Prearranged	**113,504,863**	**965,033**	**11,428**	**123.68**	**1.052**

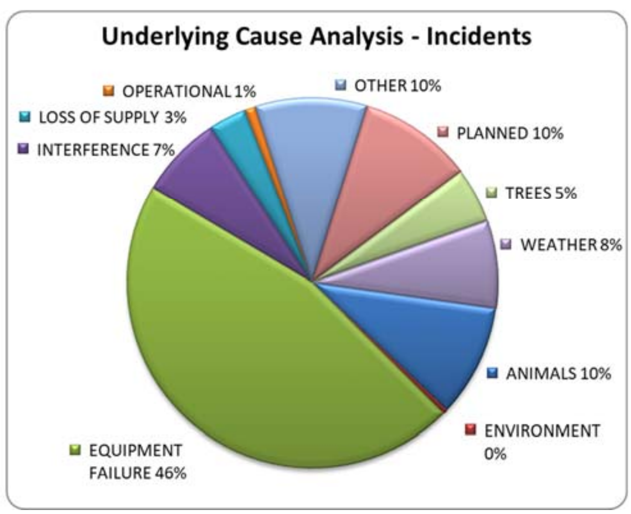

Controllable Cause SAIDI
40
35
30
25
20
15
10
5
0
35.8
3.5
0.5
0.4
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

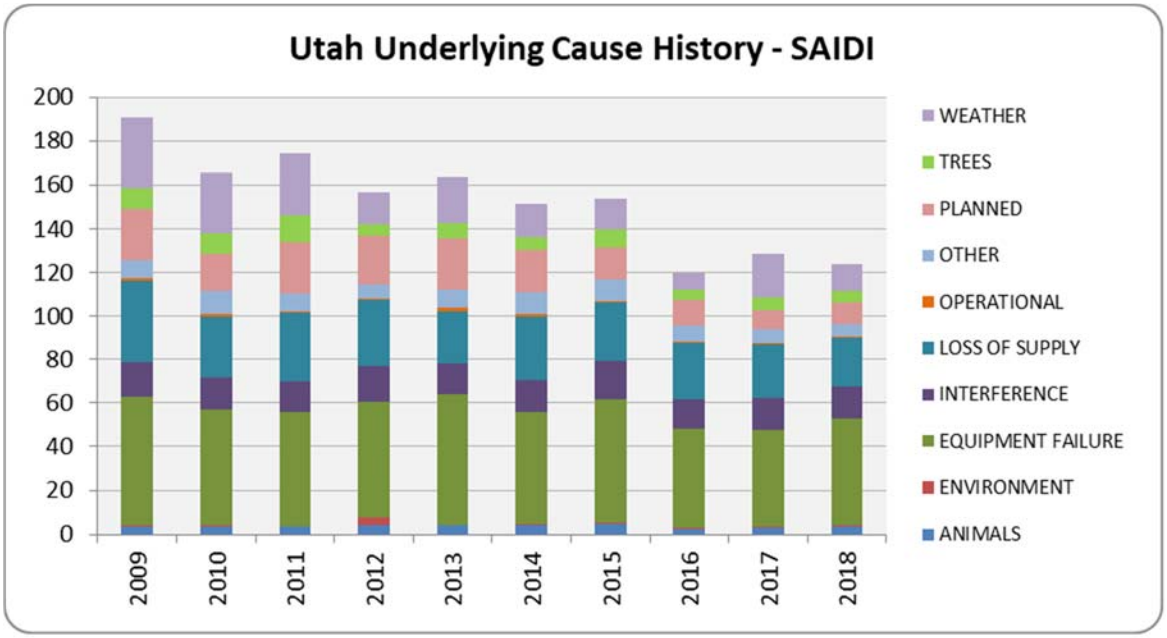

Underlying Cause Analysis - SAIDI
LOSS OF SUPPLY 18%
INTERFERENCE 12%
OPERATIONAL 0%
OTHER 5%
PLANNED 8%
TREES 4%
EQUIPMENT FAILURE 39%
WEATHER 10%
ANIMALS 3%
ENVIRONMENT 1%

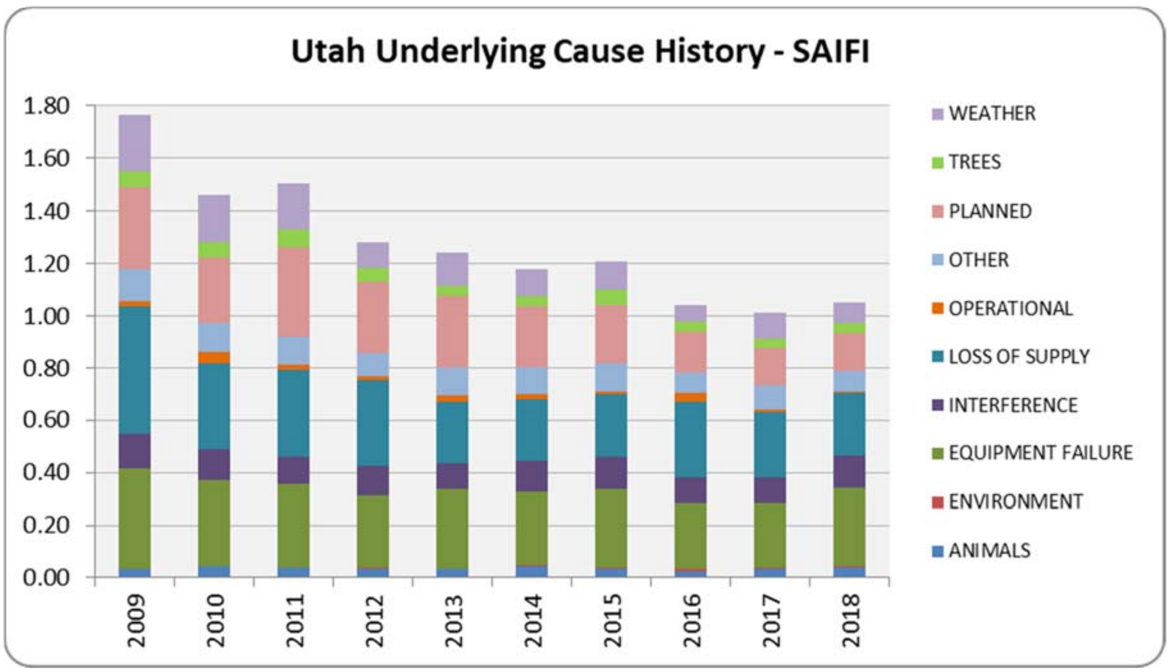

Controllable Cause SAIFI
0.25
0.20
0.15
0.10
0.05
0.00
0.227
0.040
0.009
0.003
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - SAIFI
OPERATIONAL 1%
LOSS OF SUPPLY 22%
OTHER 7%
PLANNED 14%
INTERFERENCE 12%
TREES 4%
WEATHER 7%
EQUIPMENT FAILURE 28%
ANIMALS 4%
ENVIRONMENT 1%


Controllable Cause Incidents
6,000
5,000
4,000
3,000
2,000
1,000
0
4,997
1,124
106
90
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - Incidents
OPERATIONAL 1%
OTHER 10%
LOSS OF SUPPLY 3%
PLANNED 10%
INTERFERENCE 7%
TREES 5%
WEATHER 8%
ANIMALS 10%
ENVIRONMENT 0%
EQUIPMENT FAILURE 46%

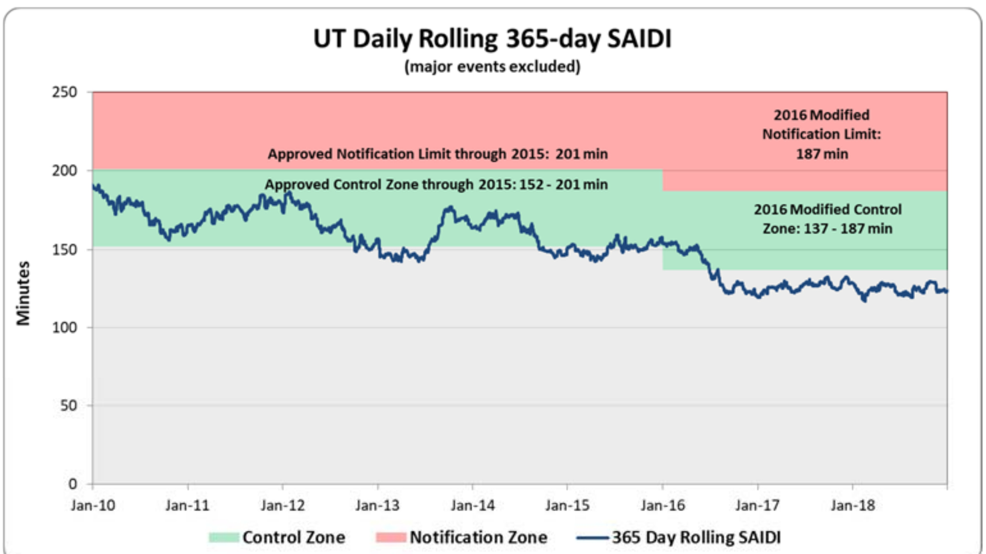

Utah Underlying Cause History - SAIDI
200
180
160
140
120
100
80
60
40
20
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

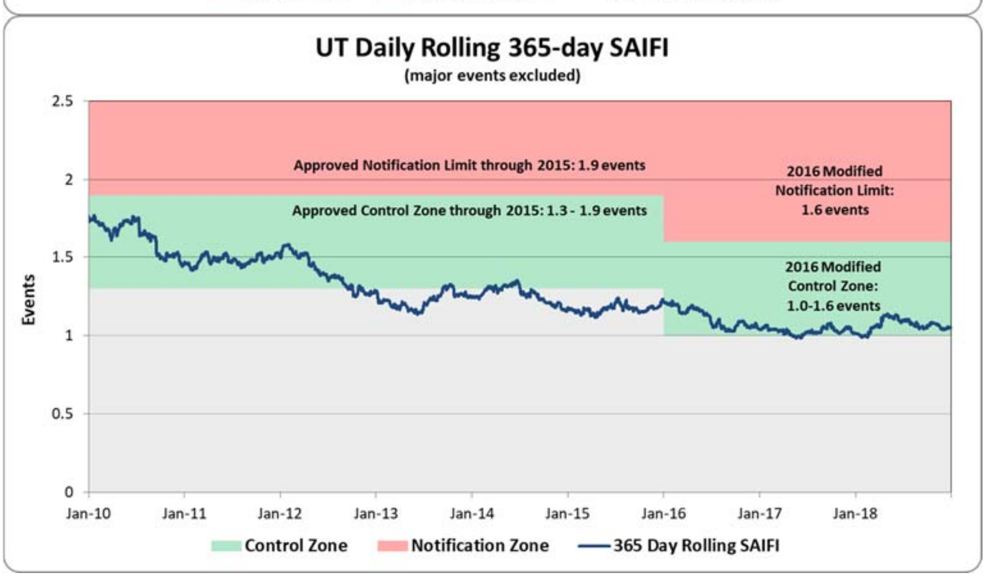

Utah Underlying Cause History - SAIFI
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

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	-	105	200	-	0.9	1.7
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.

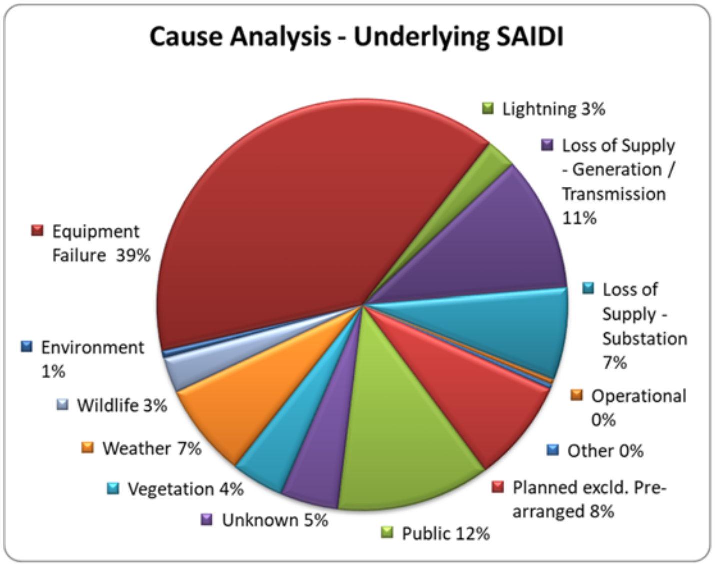
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to MAIFIe[7] are required.

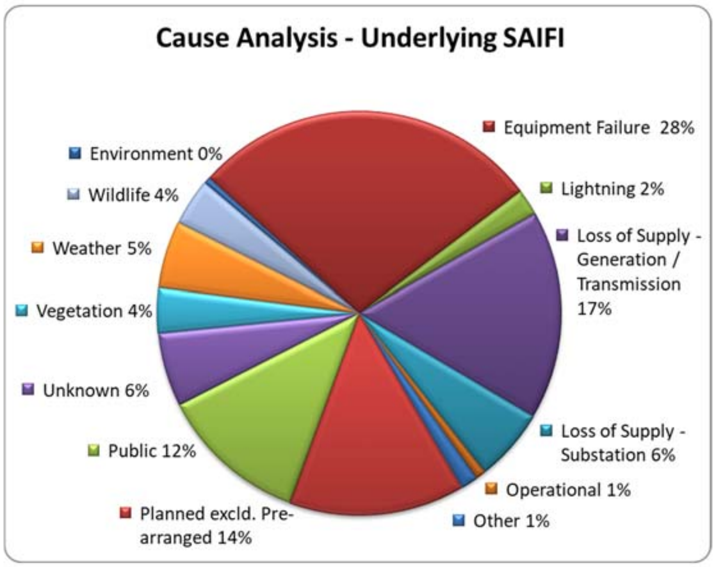
Major Events and Prearranged Excluded*	2014				2015				2016				2017				2018			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	152	1.2	129	1.21	154	1.2	127	1.48	120	1.0	115	1.76	129	1.0	127	1.11	124	1.1	118	2.17
OP AREA																				
AMERICAN FORK	113	1.0	109		134	1.1	128		92	1.0	93		77	0.8	102		85	0.8	109	
CEDAR CITY	170	1.1	151		238	1.6	146		174	1.5	116		183	1.7	109		157	1.2	136	
CEDAR CITY (MILFORD)	891	3.3	271		334	3.6	92		650	4.9	132		565	2.5	230		226	1.4	164	
JORDAN VALLEY	103	0.7	141		128	1.0	126		100	0.8	131		109	0.8	139		137	1.1	121	
LAYTON	108	0.8	127		122	1.1	109		90	0.9	103		115	0.8	149		90	0.9	101	
MOAB	412	2.3	181		426	3.5	122		278	3.0	93		190	2.4	80		111	1.1	103	
OGDEN	218	1.9	113		175	1.4	123		120	1.0	120		119	0.9	138		116	1.0	114	
PARK CITY	147	1.1	140		247	1.5	162		183	1.6	117		227	1.4	159		165	1.2	143	
PRICE	394	2.2	180		230	1.8	127		340	3.3	104		171	2.5	69		203	2.3	90	
RICHFIELD	181	1.7	104		303	2.2	137		132	1.3	101		187	2.0	95		173	1.4	125	
RICHFIELD (DELTA)	202	1.9	108		536	3.0	180		215	2.1	103		139	1.3	105		171	1.0	163	
SLC METRO	145	1.1	129		107	0.9	125		104	0.9	113		114	1.0	111		120	1.0	118	
SMITHFIELD	114	0.9	126		236	1.6	150		117	1.0	118		139	0.9	149		96	1.0	99	
TOOELE	239	2.1	115		129	1.3	103		161	1.1	151		140	1.4	100		196	1.5	135	
TREMONTON	216	2.0	111		462	4.2	110		399	3.1	129		200	2.0	99		151	1.1	137	
VERNAL	119	1.2	101		68	0.8	87		53	0.6	84		77	0.8	96		48	0.6	82	

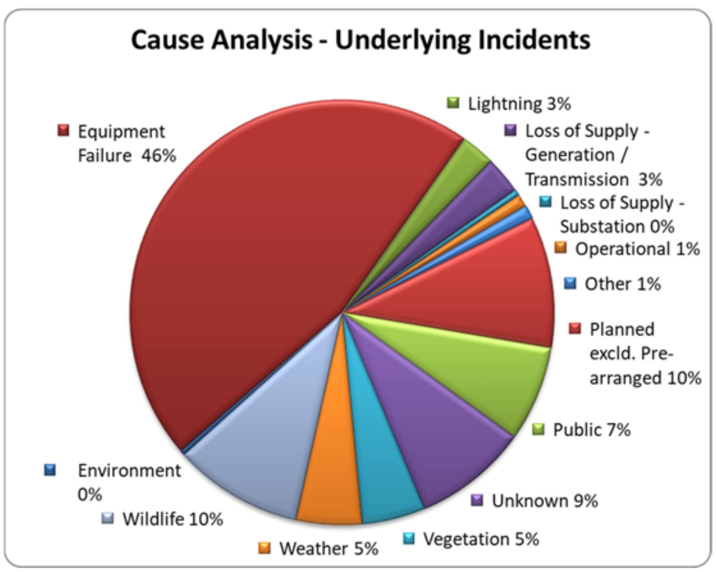
* except MAIFIe

Utah Cause Category	2014		2015		2016		2017		2018	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	1	0.0	1	0.0	1	0.0	1	0.0	1	0.0
Equipment Failure	51	0.3	56	0.3	45	0.2	44	0.2	48	0.3
Lightning	7	0.1	6	0.1	3	0.0	3	0.0	3	0.0
Loss of Supply - Generation/Transmission	23	0.2	22	0.2	13	0.2	13	0.1	13	0.2
Loss of Supply - Substation	6	0.0	5	0.0	13	0.1	11	0.1	9	0.1
Operational	1	0.0	1	0.0	1	0.0	1	0.0	0	0.0
Other	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	20	0.2	14	0.2	11	0.2	8	0.1	10	0.1
Public	15	0.1	18	0.1	14	0.1	15	0.1	15	0.1
Unknown	10	0.1	10	0.1	7	0.1	6	0.1	6	0.1
Vegetation	6	0.0	8	0.1	5	0.0	6	0.0	5	0.0
Weather	8	0.0	8	0.0	5	0.0	16	0.1	9	0.1
Wildlife	4	0.0	5	0.0	2	0.0	3	0.0	3	0.0
UTAH Underlying	**152**	**1.2**	**154**	**1.2**	**120**	**1.0**	**129**	**1.0**	**124**	**1.1**

[7] MAIFIe events are measured using the circuit customer count for those circuits where a trip and reclose occurred during the reporting period, and do not include customer counts for circuits where no event was recorded.


Cause Analysis - Underlying SAIDI
Lightning 3%
Loss of Supply - Generation / Transmission 11%
Loss of Supply - Substation 7%
Operational 0%
Other 0%
Planned excld. Pre-arranged 8%
Public 12%
Unknown 5%
Vegetation 4%
Weather 7%
Wildlife 3%
Environment 1%
Equipment Failure 39%


Cause Analysis - Underlying SAIFI
Equipment Failure 28%
Lightning 2%
Loss of Supply - Generation / Transmission 17%
Loss of Supply - Substation 6%
Operational 1%
Other 1%
Planned excld. Pre-arranged 14%
Public 12%
Unknown 6%
Vegetation 4%
Weather 5%
Wildlife 4%
Environment 0%


Cause Analysis - Underlying Incidents
Lightning 3%
Equipment Failure 46%
Loss of Supply - Generation / Transmission 3%
Loss of Supply - Substation 0%
Operational 1%
Other 1%
Planned excld. Pre-arranged 10%
Public 7%
Unknown 9%
Vegetation 5%
Weather 5%
Wildlife 10%
Environment 0%

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.

2016-2018 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	24	$0.73	10	357,796	1,018,232	$1.20	$0.53	2	12
Cedar City	7	$1.17	4	495,559	632,351	$1.71	$1.72	0	3
Jordan Valley	59	$1.74	10	700,421	1,283,304	$1.16	$0.67	1	48
Layton	11	$0.81	5	921,938	3,005,788	$0.75	$0.32	0	6
Moab	7	$7.48	1	4,665	13,329	$6.94	$2.18	0	6
Montpelier	2	$0.29	1	1,055,517	3,372,083	$0.17	$0.10	1	0
Ogden	37	$1.13	10	468,265	1,404,521	$1.46	$0.51	1	26
Park City	17	$0.63	10	413,199	2,083,609	$0.43	$0.10	0	7
Price	6	$3.34	1	74,281	530,577	$0.88	$0.13	1	4
Richfield	13	$3.71	1	7,621	23,095	$4.49	$0.77	0	12
SLC Metro	45	$1.88	6	141,589	564,052	$1.86	$0.48	1	38
Smithfield	9	$1.03	1	1,387	1,981	$7.64	$9.26	0	8
Tooele	12	$1.53	3	55,382	12,900	$2.24	$17.19	1	8
Tremonton	5	$0.47	2	221,220	659,947	$0.56	$0.21	0	3
Vernal	7	$0.78	6	194,474	476,303	$0.64	$0.38	0	1
Total	**261**	**$1.39**	**71**	**5,113,314**	**15,082,071**	**$0.90**	**$0.38**	**8**	**182**

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 12/31/2018
Program Year 17: (CY2016)			
Red Mountain 33	COMPLETE	1283	1272
Fountain Green 12	COMPLETE	266	165
Middleton 24	COMPLETE	253	231
Willowridge 11	COMPLETE	177	116
Summit Park 11	COMPLETE	116	59
TARGET SCORE = **335**		**419**	**369**
Program Year 16: (CY2015)			
Nibley 21	COMPLETE	179	273
Brighton 12	COMPLETE	270	96
Rattlesnake 22	COMPLETE	456	458
Decker Lake 12	COMPLETE	167	51
Toquerville 31	COMPLETE	475	227
TARGET SCORE = **248**	**Target Met**	**309**	**221**
Program Year 15: (CY2014)			
Skull Valley 11	COMPLETE	468	166
Fort Douglas 13	COMPLETE	417	89
Parowan Valley 25	COMPLETE	408	269
Brighton 21	COMPLETE	364	199
Bush 12	COMPLETE	281	137
TARGET SCORE = **248**	**Target Met**	**310**	**172**

[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, 2018

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 12/31/2018
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	129
Eden 11	COMPLETE	116	121
Bush 11	COMPLETE	228	79
Pioneer 12	COMPLETE	177	87
Grantsville 12	COMPLETE	250	72
TARGET SCORE = 108	**Target Met**	**135**	**98**
Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	102
East Bench 12	COMPLETE	112	17
Clinton 11	COMPLETE	133	64
Redwood 16	COMPLETE	145	65
Orangeville 11	COMPLETE	114	68
TARGET SCORE = **114**	**Target Met**	**142**	**63**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	83
Huntington City 12	COMPLETE	285	61
Magna 15	COMPLETE	140	27
Gunnison 12	COMPLETE	110	109
Capitol 11	COMPLETE	129	61
TARGET SCORE = **134**	**Target Met**	**167**	**68**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	51
North Bench 13	COMPLETE	95	81
Newgate 14	COMPLETE	164	73
Newton 12	COMPLETE	105	41
St Johns 11	COMPLETE	547	134
TARGET SCORE = **162**	**Target Met**	**203**	**76**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	78
Mathis 12	COMPLETE	132	111
Parrish 11	COMPLETE	137	23
Valley Center 11	COMPLETE	169	37
Hammer 15	COMPLETE	95	19
TARGET SCORE = **104**	**Target Met**	**129**	**53**

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 = 86%					
January	February	March	April	May	June
91%	88%	86%	94%	92%	84%
July	August	September	October	November	December
80%	72%	88%	89%	78%	93%

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	118 minutes
Total Performance	118 minutes

2.11 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	82%
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 three dates identified as a wide-scale outage days; call statistics are shown in the table below. On January 19th a tree downed a 115 kV line in Coos Bay, Oregon causing an outage to approximately 25,700 customers with outage durations ranging from 25 to 29 minutes. On April 9th customers in Jordan Valley, Utah experienced an outage when a fault occurred at a transmission substation causing an outage to approximately 51,500 customers with outage durations ranging from 38 minutes to 1 hours 18 minutes. On June 19th a transmission substation in Grants Pass, Oregon experienced an outage which affected approximately 54,000 customers with outage durations ranging from 8 minutes to 2 hours 43 minutes. On September 18th a loss of transmission line outage occurred in Grants Pass, Oregon, when a contractor working on the line caused a fault tripping the circuit breaker. The event affected 44,617 customers for 15 minutes. On November 14th, Grants Pass, Oregon, experienced an outage due to an operator error when low voltage issues where occurring. The event affected 31,564 customers with outage durations ranging from 33 minutes to 41 minutes. On December 12th, Grants Pass, Oregon, experienced a loss of substation outage when crews testing the SCADA system tripped the system. The event affected 44,869 customers with outage durations ranging from 10 to 23 minutes.

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
1/19/2018	16:15	16:29	432	0	286	591	129
	16:30	16:44	3013	498	0	339	6
	16:45	16:59	1754	313	0	78	4
	17:00	17:14	529	0	1	112	5
4/9/2018	12:15	12:29	3420	818	178	366	118
	12:30	12:44	4608	1152	7	152	21
	12:45	12:59	2275	238	12	115	26
	13:00	13:14	868	3	10	119	48
	13:15	13:29	683	0	3	78	19
6/19/2018	10:00	10:14	5562	859	69	118	49
	10:15	10:29	6980	1052	32	112	52
	10:30	10:44	3464	452	26	216	34
	10:45	10:59	511	0	4	127	26
9/18/2018	10:00	10:14	854	100	128	453	78
	10:15	10:29	4619	776	281	223	97
	10:30	10:44	481	69	3	151	11
	10:45	11:00	497	0	12	210	61

UTAH

January 1 – December 31, 2018

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
11/14/2018	8:30	8:45	1876	175	348	920	170
	8:45	9:00	2227	284	144	875	168
	9:00	9:15	1232	156	5	147	17
	9:15	9:30	282	0	1	141	6
12/12/2018	15:45	16:00	332	0	12	695	64
	16:00	16:15	4197	409	537	553	115
	16:15	16:30	450	0	2	152	6
	16:30	16:45	363	0	0	177	8

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 2018

Utah

	Description	2018 Events	2018 Failures	2018 % Success	2018 Paid	2017 Events	2017 Failures	2017 % Success	2017 Paid
CG1	Restoring Supply	937,717	0	100.00%	$0	928,180	1	100.00%	$50
CG2	Appointments	8,956	11	99.88%	$550	10,064	10	99.90%	$500
CG3	Switching on Power	4,839	4	99.92%	$200	5,620	2	99.96%	$100
CG4	Estimates	1,362	6	99.56%	$300	1,394	7	99.50%	$350
CG5	Respond to Billing Inquiries	1,640	8	99.51%	$400	1,822	7	99.62%	$350
CG6	Respond to Meter Problems	981	5	99.49%	$250	917	1	99.89%	$50
CG7	Notification of Planned Interruptions	137,720	65	99.95%	$3,250	101,319	29	99.97%	$1,450
		1,093,215	**99**	**99.99%**	**$4,950**	**1,049,316**	**57**	**99.99%**	**$2,850**

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.

Substations and Major Equipment

---

[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.

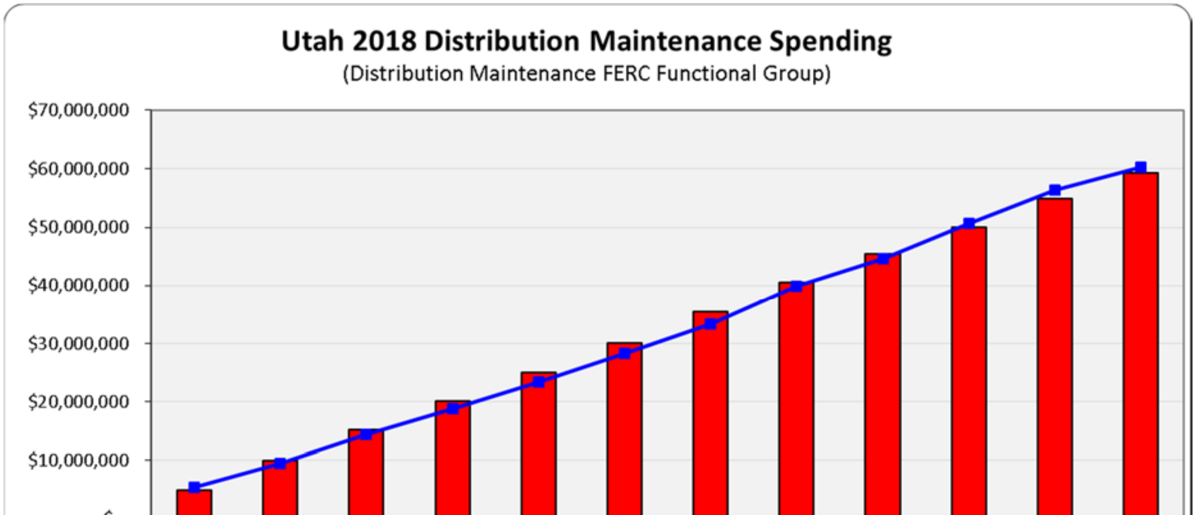
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

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.

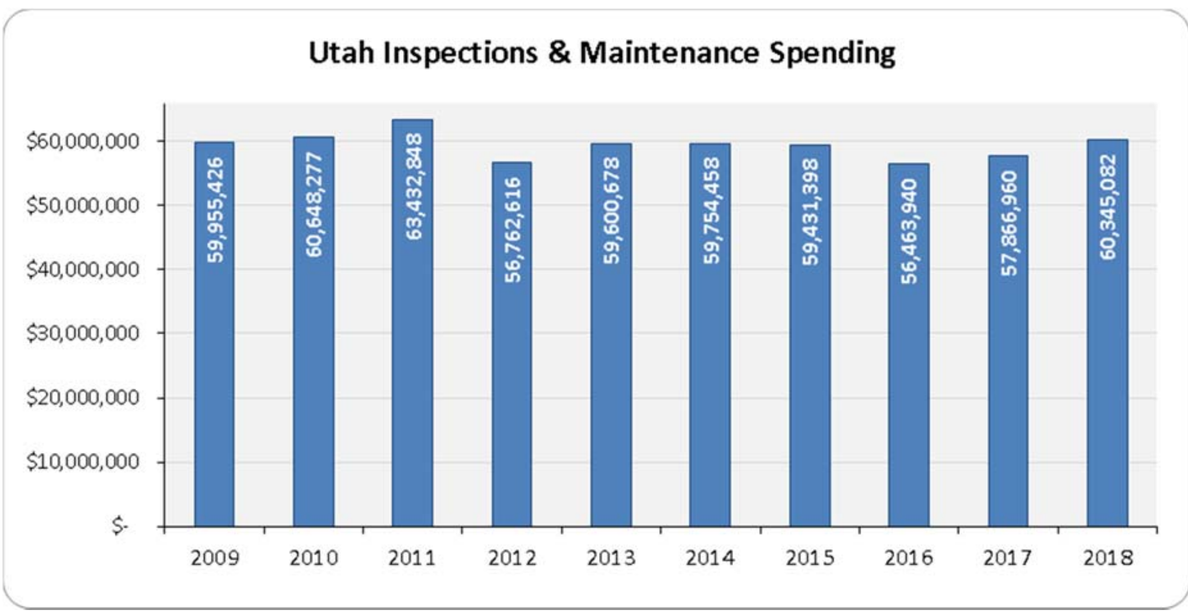
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending[12,13]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$4,909,554	$10,018,683	$15,117,217	$20,072,065	$24,994,681	$29,992,562	$35,476,450	$40,591,091	$45,370,554	$49,968,406	$54,979,058	$59,420,610
Actual	$5,303,898	$9,521,217	$14,377,283	$18,752,627	$23,400,879	$28,183,567	$33,303,827	$39,932,648	$44,700,227	$50,725,310	$56,354,588	$60,345,082

3.2.1 Maintenance Historical Spending

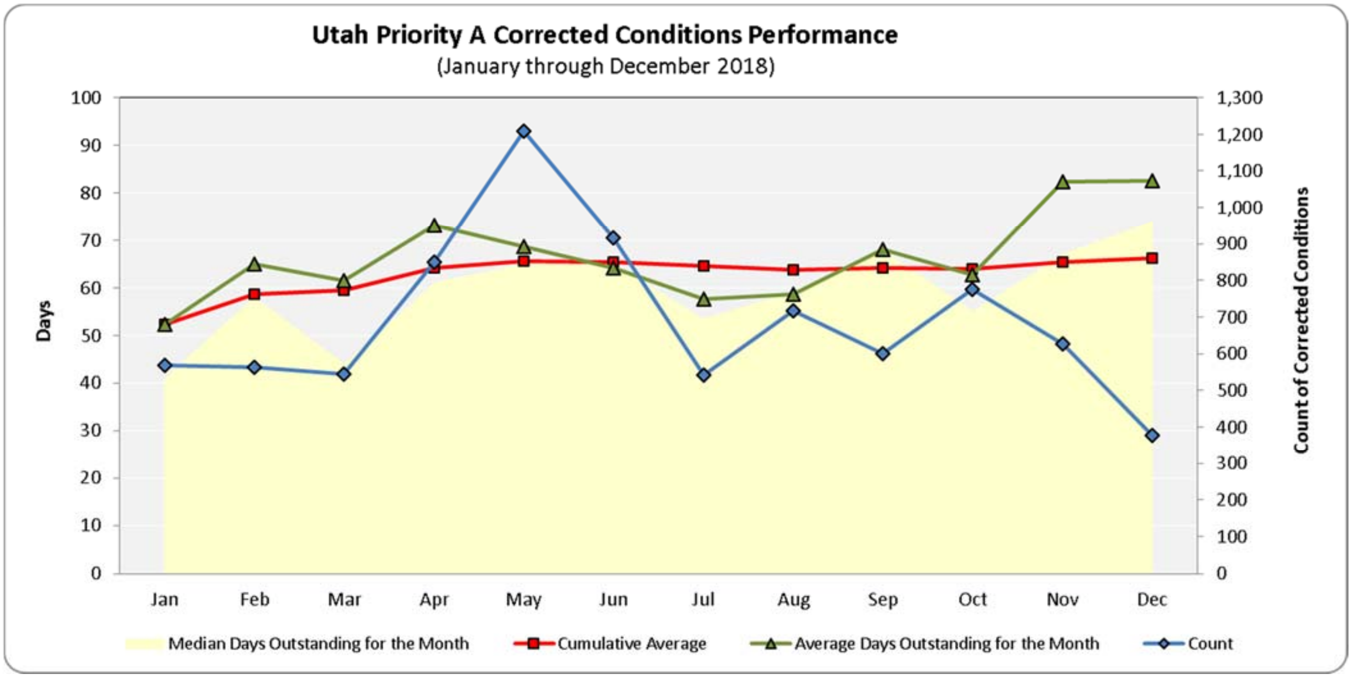


[12] Maintenance spending reflected does not include Vegetation Management and Fault Locating costs, which when reporting under FERC accounting methodology, FERC has traditionally considered maintenance.

[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

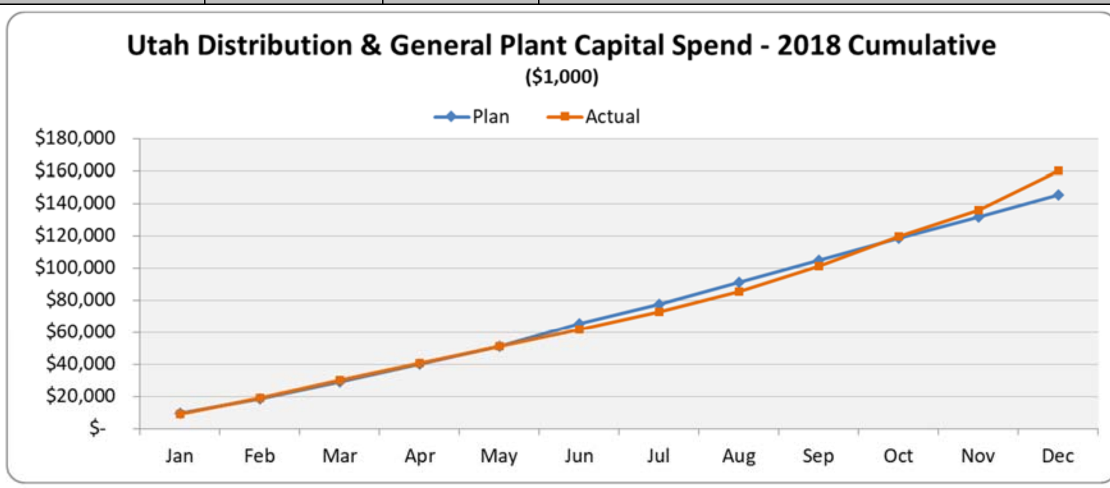
District	Plant Locality	Structure #	Condition	Inspection Remarks	Inspection Date	Anticipated Completion Date	Explanation
Jordan Valley	11303001	269401	CLEARSVC	CLEARANCE CROSSING SERVICE	12/21/2017	Corrected	Street light issue owned by Draper city. After recent field inspection the condition was found to be corrected and condition cleared.
American Fork	11405002	186304	BOGUY	RMP DOWNGUY LESS THAN 15'6" OVER DRIVABLE SURFACE	2/23/2018	3/1/2019	This will be done on a customer pole relocation job. We have been waiting on the developer/customer to finish required work on their end. New curb and gutter is scheduled to be installed 2/26/19 and we can start moving forward after that.
American Fork	78175	132	COOTHER	LOOSE HARDWARE 16865952	3/2/2018	Corrected	Further inspection deemed hardware was not loose and no correction needed. Condition cleared 1/18/2019.
Jordan Valley	77019	10/012	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892870	3/6/2018	Corrected 1/7/2019	There was prolonged discussion whether this steel structure needed separate grounding. Decision was made that they didn't require separate grounding and conditions were cleared.
Jordan Valley	77019	8/016	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892890	3/7/2018	Corrected 1/7/2019	
Jordan Valley	77019	3/016	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892879	3/7/2018	Corrected 1/7/2019	
Jordan Valley	77019	4/016	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892884	3/7/2018	Corrected 1/7/2019	
Jordan Valley	77019	4/013	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892881	3/7/2018	Corrected 1/7/2019	
Jordan Valley	77019	4/015	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892883	3/7/2018	Corrected 1/7/2019	
Jordan Valley	77019	3/015	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16892878	3/7/2018	Corrected 1/7/2019	
Richfield	82105	56	BOGRDBND	BROKEN OR MISSING GROUND_BOGROUND <8FT 16878336	3/7/2018	Corrected 10/29/18	Held for efficiency to be corrected with another condition on this structure requiring it to be re-framed "IA" to "PS" type.
Richfield	82105	56	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16878336	3/7/2018	Corrected 10/29/18	
Richfield	82105	55	BOGRD	BROKEN OR MISSING GROUND DIST & TRANS 16878351	3/7/2018	Corrected 10/29/18	

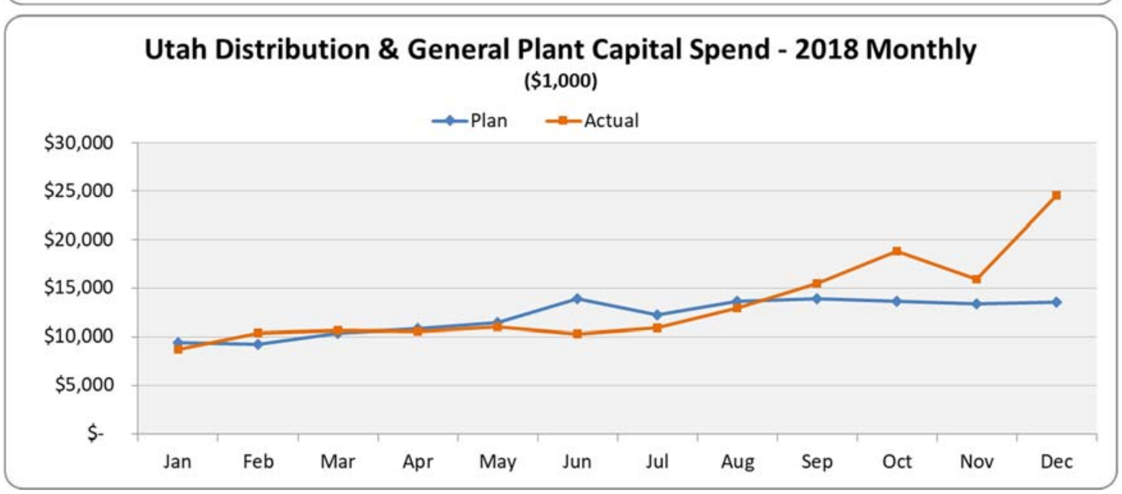
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January –December 2018

Investment	Actuals ($M)	Plan ($M)	Significant Variance Explanations
1. Mandated	$11.9	$12.3	Mandated NERC reliability over plan, (+$1.1M); mandated net metering under plan, (-$2.6M).
2. New Connect	$59.4	$45.5	Residential, commercial and industrial new revenue connections over plan, (+$13.7M).
3. System Reinforcement	$12.6	$9.7	Substation reinforcement over plan, (+$1.6M).
4. Replacement	$55.6	$56.4	Replacements for facilities over plan, (+$1.6M); replacements for vehicles (transport) and storm & casualty under plan, (-$3.4M).
5. Upgrade & Modernize	$20.6	$21.2	Functional distribution and substation reliability upgrades over plan, (+$3.0M); feeder improvements and economically justified improvements under plan, (-$3.7M). -- (Note: $9.1M spend was posted in December for Utah Advanced Metering Infrastructure project, due to project timing.)
Total	$160.00	$145.2	



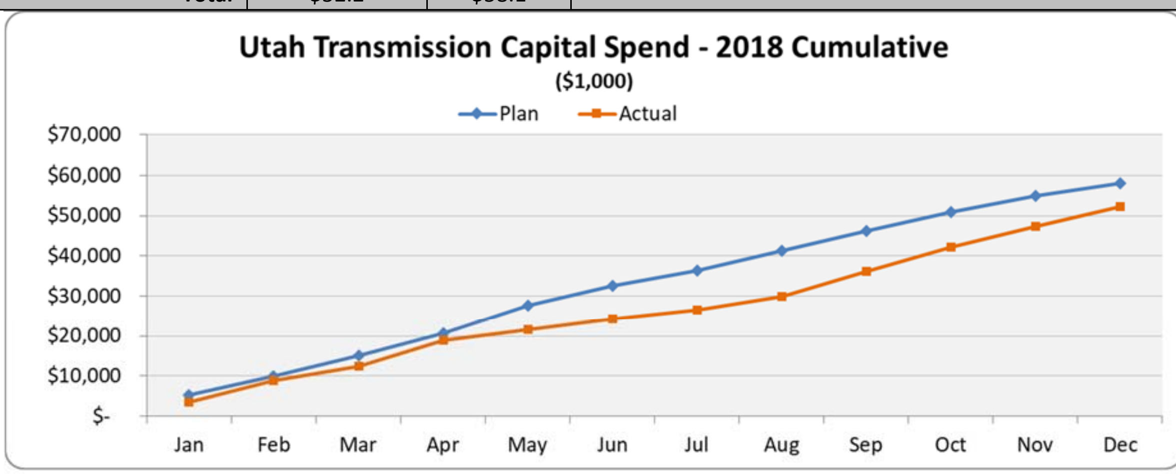


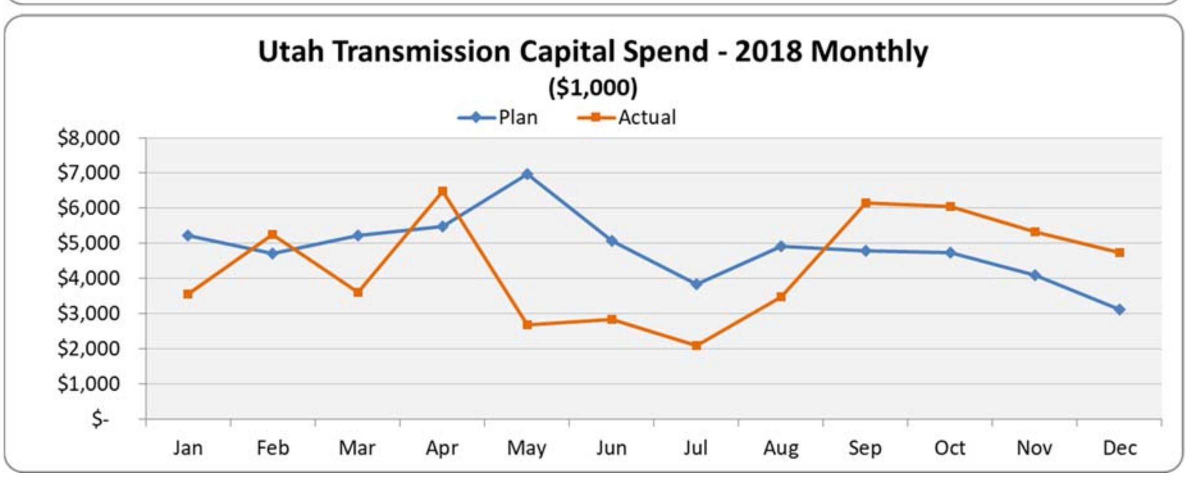
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January –December 2018

Investment		Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	9.9	10.4	Mandated NERC reliability under plan, (-$1.5M).
2.	New Connect	0.7	0.1	
3.	Local Trans-mission System Reinforcements	3.8	6.8	Sub-transmission system reinforcements (primarily Jordanelle-Midway 138kV Line with Heber Power & Light Co.) under plan, (-$3.8M).
**4.	Main Grid Reinforcements / Interconnections	14.6	20.7	Syracuse Second Transformer (-$2.9M), and TPL Backup Bus Differential Relays (-$1.0M) under plan.
**5.	Energy Gateway Transmission	1.0	3.5	Populus-Terminal 345kV Line (-$2.4M) under plan.
6.	Replacement	21.5	15.5	Replacements for substation switchgear/breakers/reclosers and storm & casualty over plan, (+$9.3M); replacements for overhead transmission lines-other under plan, (-$1.4M).
7.	Upgrade & Modernize	0.6	1.1	
	Total	$52.2	$58.1	





* 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

	2017	2018												
	YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YEAR
Residential														
UT South	1,129	100	78	139	139	135	148	120	121	83	100	120	107	1,390
UT North/Metro	6,223	618	440	666	442	617	738	375	505	475	704	412	367	6,359
UT Central	11,018	1,018	1,063	1,020	1,018	961	1,173	860	971	830	1,046	941	816	11,717
Total Residential	**18,370**	**1,736**	**1,581**	**1,825**	**1,599**	**1,713**	**2,059**	**1,355**	**1,597**	**1,388**	**1,850**	**1,473**	**1,290**	**19,466**
Commercial														
UT South	208	13	12	20	22	24	38	12	20	15	35	16	26	253
UT North/Metro	785	91	75	45	62	36	70	65	63	57	78	68	53	763
UT Central	847	61	89	70	71	77	93	55	100	69	79	86	113	963
Total Commercial	**1,840**	**165**	**176**	**135**	**155**	**137**	**201**	**132**	**183**	**141**	**192**	**170**	**192**	**1,979**
Industrial														
UT South	2	0	0	0	0	0	0	0	0	0	0	0	0	0
UT North/Metro	3	1	0	1	2	2	1	1	0	1	0	0	0	9
UT Central	5	0	0	0	0	0	0	1	0	1	0	0	0	2
Total Industrial	**10**	**1**	**0**	**1**	**2**	**2**	**1**	**2**	**0**	**2**	**0**	**0**	**0**	**11**
Irrigation														
UT South	38	5	6	3	8	9	10	10	3	2	4	3	3	66
UT North/Metro	5	0	1	1	0	1	1	1	0	0	1	1	0	7
UT Central	9	0	3	2	1	4	5	1	2	1	0	4	0	23
Total Irrigation	**52**	**5**	**10**	**6**	**9**	**14**	**16**	**12**	**5**	**3**	**5**	**8**	**3**	**96**
TOTAL New Connects														
UT South	1,377	118	96	162	169	168	196	142	144	100	139	139	136	1,709
UT North/Metro	7,016	710	516	713	506	656	810	442	568	533	783	481	420	7,138
UT Central	11,879	1,079	1,155	1,092	1,090	1,042	1,271	917	1,073	901	1,125	1,031	929	12,705
TOTAL New Connects	**20,272**	**1,907**	**1,767**	**1,967**	**1,765**	**1,866**	**2,277**	**1,501**	**1,785**	**1,534**	**2,047**	**1,651**	**1,485**	**21,552**

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, 2018 through December 31, 2018
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2018-12/31/2018 Miles Planned	1/1/2018-12/31/2018 Actual Miles	1/1/2018-12/31/2018 Ahead/ Behind	1/1/2018-12/31/2018 % 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	10,747	3,361	3,361	0	100%	7,164	6,940	-224	97%
AMERICAN FORK	830	311	311	0	100%	553	484	-69	88%
CEDAR CITY	1,378	169	169	0	100%	919	828	-91	90%
JORDAN VALLEY	774	186	186	0	100%	516	544	28	105%
LAYTON	299	260	260	0	100%	199	267	68	134%
MOAB	630	337	337	0	100%	420	520	100	124%
OGDEN	885	248	248	0	100%	590	499	-91	85%
PARK CITY	551	176	176	0	100%	367	397	30	108%
PRICE	592	171	171	0	100%	395	437	42	111%
RICHFIELD	1,344	657	657	0	100%	896	812	-84	91%
SL METRO	1,235	302	302	0	100%	823	827	4	100%
SMITHFIELD	765	193	193	0	100%	510	469	-41	92%
TOOELE	480	144	144	0	100%	320	236	-84	74%
TREMONTON	734	115	115	0	100%	489	444	-45	91%
VERNAL	250	92	92	0	100%	167	176	9	105%

Distribution cycle $/tree:	$176
Distribution cycle $/mile:	$2,412
Distribution cycle removal %	10%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	% of miles on/behind Schedule
6,575	1,527	1,745	218	114%

Transmission $/mile: $1,072

Current distribution cycle begain 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, 2018 through December 31, 2018
Column c: Actual overhead distribution pole miles worked during the period January 1, 2018 through December 31, 2018
Column d: Miles ahead or behind for the period January 1, 2018 through December 31, 2018 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2018 through December 31, 2018 ((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

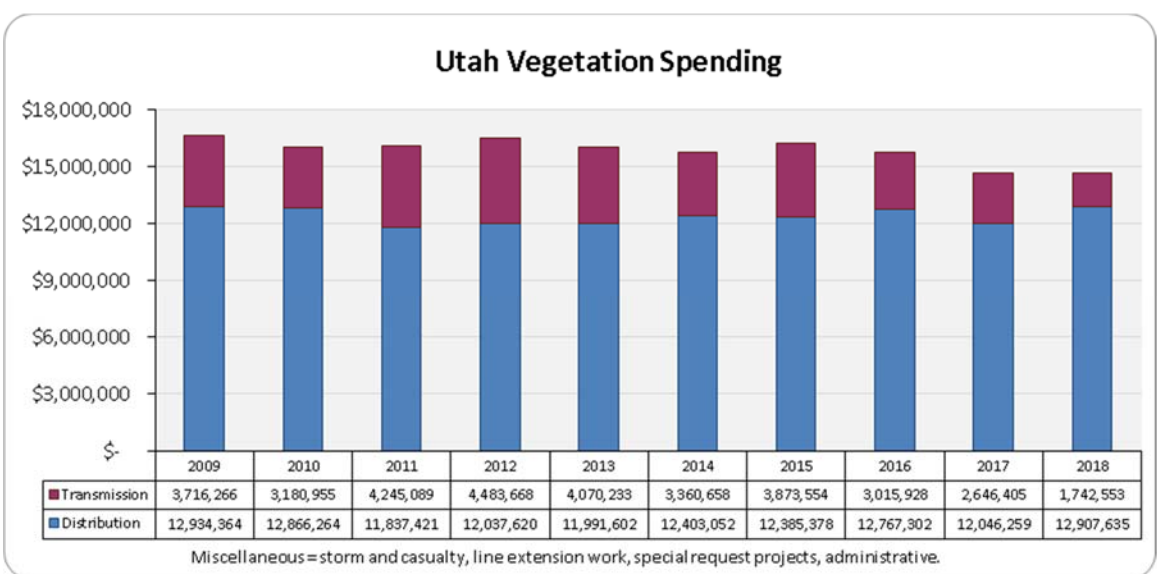
Tree Program Reporting

	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 2018	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$1,339,206	$779,167	$560,039	$139,133	$236,667	-$97,534
Feb	$1,262,626	$979,167	$283,459	$82,148	$236,667	-$154,519
Mar	$869,930	$879,167	-$9,237	$149,876	$236,667	-$86,791
Apr	$1,002,872	$879,167	$123,705	$163,541	$236,667	-$73,126
May	$882,079	$879,167	$2,912	$216,585	$236,667	-$20,082
Jun	$1,029,902	$979,167	$50,735	$227,427	$236,667	-$9,240
Jul	$624,048	$879,167	-$255,119	$174,468	$236,667	-$62,199
Aug	$1,005,631	$879,167	$126,464	$121,956	$236,667	-$114,711
Sep	$1,007,915	$879,167	$128,748	$104,724	$236,667	-$131,943
Oct	$1,412,397	$779,167	$633,230	$109,933	$236,667	-$126,734
Nov	$1,295,401	$879,167	$416,234	$69,396	$236,667	-$167,271
Dec	$1,175,628	$879,167	$296,461	$183,365	$236,667	-$53,302
Total	$12,907,635	$10,550,004	$2,357,631	$1,742,553	$2,840,004	-$1,097,451

Average # Tree Crews on Property (YTD) **51**

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.

ORR

ORR is an acronym for Open Reliability Reporting, which shifts the company's reliability program from a circuit based metric (RPI) to a targeted approach reviewing performance in a local area, measured by customer minutes lost. Project funding is based on cost effectiveness as measured by the cost per avoided annual customer minute interrupted.

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
1/1-12/31/2018	917,739	5.41	4,969,384
1/1-12/31/2019	946,168	5.08	4,809,295

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.

CERTIFICATE OF SERVICE

Docket No. 19-035-19

I hereby certify that on May 1, 2019, a true and correct copy of the foregoing was served by electronic mail to the following:

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