ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84116

April 28, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attention: Gary Widerburg
Commission Secretary

Re: Docket 08-035-55
Service Quality Standards –June 2013 Service Quality Review Report
Docket No. 13-035-70,
Rocky Mountain Power's Service Quality Review Report

In compliance with the Commission's June 11, 2009 order in Docket 08-035-55 and pursuant to the requirements of Rule R746-313, Rocky Mountain Power submits the Service Quality Review Report for the period January through December 2015. Rocky Mountain Power will schedule a meeting in the near future to review the attached with the Commission and other interested parties.

It is respectfully requested that all formal correspondence and Staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com
bob.lively@pacificorp.com

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

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Sincerely,

Jeffrey K. Larsen/[illegible]

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH
SERVICE QUALITY
REVIEW

January 1 – December 31, 2015
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 recently-adopted state rules.

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.

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 Regulations R746-313. The Company, Commission and other stakeholders have developed mechanisms that comply with these rules to retire the Company's Service Standards Program, as expired on December 31, 2011.

1.2 Rocky Mountain Power Performance Standards[1]

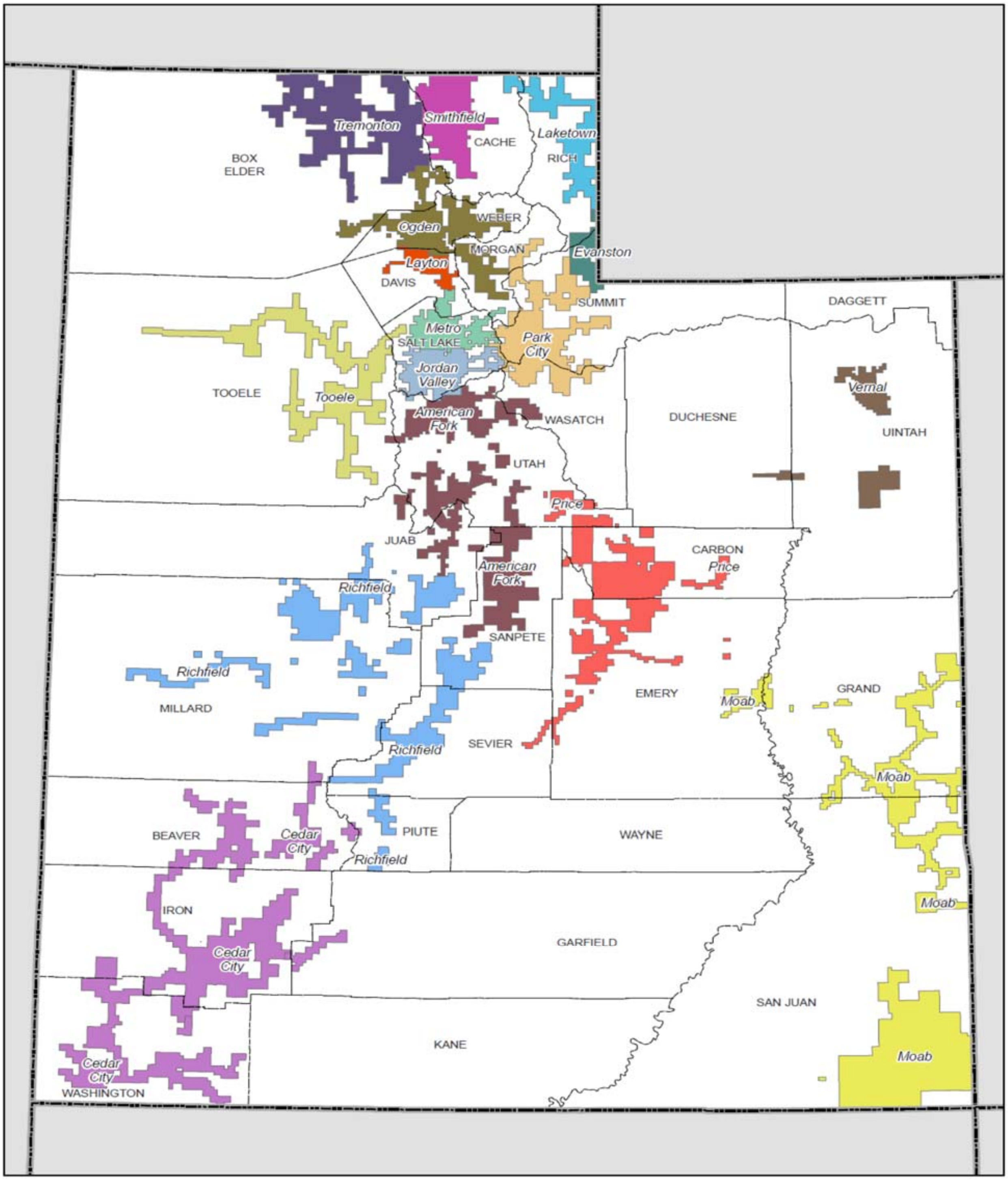
*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	Utah Commission adopted baselines recognizing 365-day rolling (rather than calendar) performance levels of between 152-201 minutes.
*Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	Utah Commission adopted baselines recognizing 365-day rolling (rather than calendar) performance levels of between 1.3-1.9 events.
Network Performance Standard 3: Improve Under Performing Circuits	The Company will reduce by 20% the circuit performance indicator (CPI) for a maximum of five underperforming circuits on an annual basis within five years after selection.
*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.

[1] In 2012, rules were codified in Utah Regulations R746-313. The Company, Commission and other stakeholders have developed mechanisms that comply with these rules to retire the Company's Service Standards Program, as expired on December 31, 2011.

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

As shown in charts under subsections 2.1 and 2.2 below, the Company's 2015 underlying reliability results fall within the Company's control zones, which are shown as green in the graphic. History reflecting these metrics is displayed in Sections 2.3 and 2.4. Baselines are explored 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.

In 2015, there were two major events[2], both of which were accepted for designation as major events by the Utah Commission upon recommendation of the Utah Division of Public Utilities. Also four significant event days[3] recorded. Anecdotally, the count of major event and significant event days indicates strong resilience by the system during the reporting period, continuing the strong performance delivered during 2014.

Utah Major Events 2015		
Date	**Cause**	**SAIDI**
April 14-16, 2015	Wind and snow storm	34.47
December 14-15, 2015	Snow Storm	7.82
	TOTAL	**42.29**

- **April 14-16, 2015**
  A spring storm brought light rain, followed by high winds and heavy, wet snowfall to various regions of Utah causing substantial damage to Rocky Mountain Power's facilities and a significant impact on its reliability performance from April 14, 2015 through April 16, 2015. Early in the event light rain, which coincided with salt and pollution-laden hardware, caused pole fires which necessitated replacement of a significant amount of poles and crossarms. As the storm continued, wind-blown and snow-laden trees toppled into electrical facilities, blowing fuses, pulling wire down or breaking poles. This major event filing was accepted by the Utah Commission on 7/8/15 in Docket 15-035-54.

- **December 14-15, 2015**
  On December 14, 2015, Utah experienced a severe winter storm. The storm was recorded as the largest snow storm in three years in the greater Salt Lake City area, accumulating up to 22 inches of snow over the course of three days. As snow accumulated, wind-blown and snow-laden trees and branches toppled onto electrical facilities, blowing fuses, pulling wire down or breaking poles. During the event 50% of customer minutes lost were attributed to heavy snow and tree related outages. Another big contributing cause was loss of transmission line, where those which had been damaged resulted in 32% of the event customer minutes lost. This major event filing was accepted by the Utah Commission on 1/27/16 in Docket 16-035-02.

[2] Major event threshold shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
2015	869,108	6.52	5,669,347
2016	876,438	6.06	5,312,799

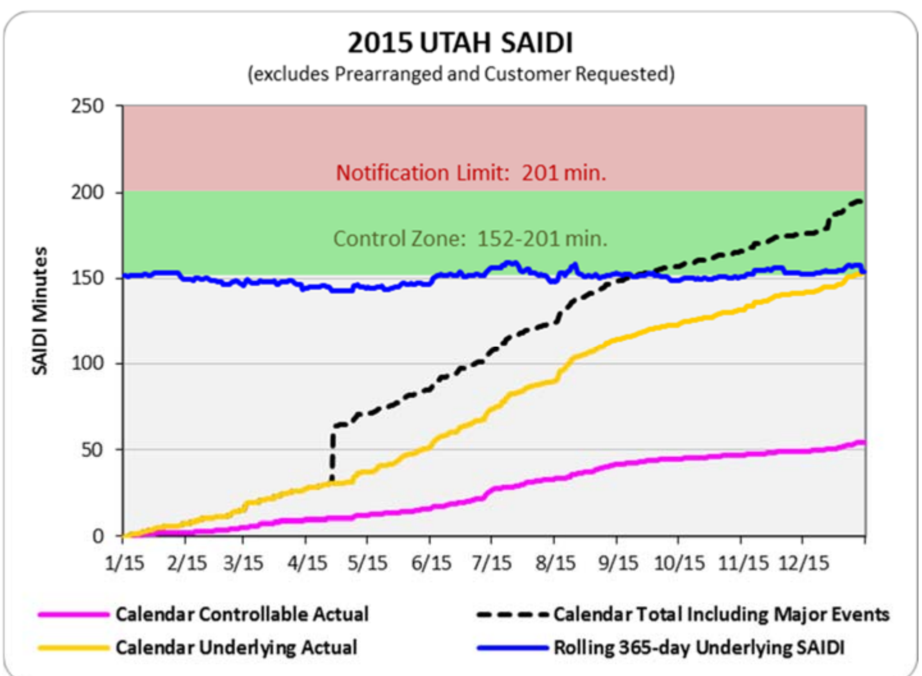
[3] Significant event days are 1.75 times the standard deviation of the company's natural log daily SAIDI results (by state).

Utah Significant Event Days 2015			
Date	**Cause: General Description**	**Underlying SAIDI**	**% of Total Underlying SAIDI (154)**
March 2, 2015	Winter storm. Loss of transmission line in Richfield	3.2	2.1%
April 24, 2015	Loss of transmission/weather-wind in Layton.	2.6	1.7%
July 6, 2015	Several events impacted the state. American Fork experienced a loss in supply due to equipment failure.	2.5	1.6%
August 3, 2015	Loss of Transmission, flash over.	4.8	3.1%
	TOTAL	**13.1**	**8.5%**

2.1 System Average Interruption Duration Index (SAIDI)

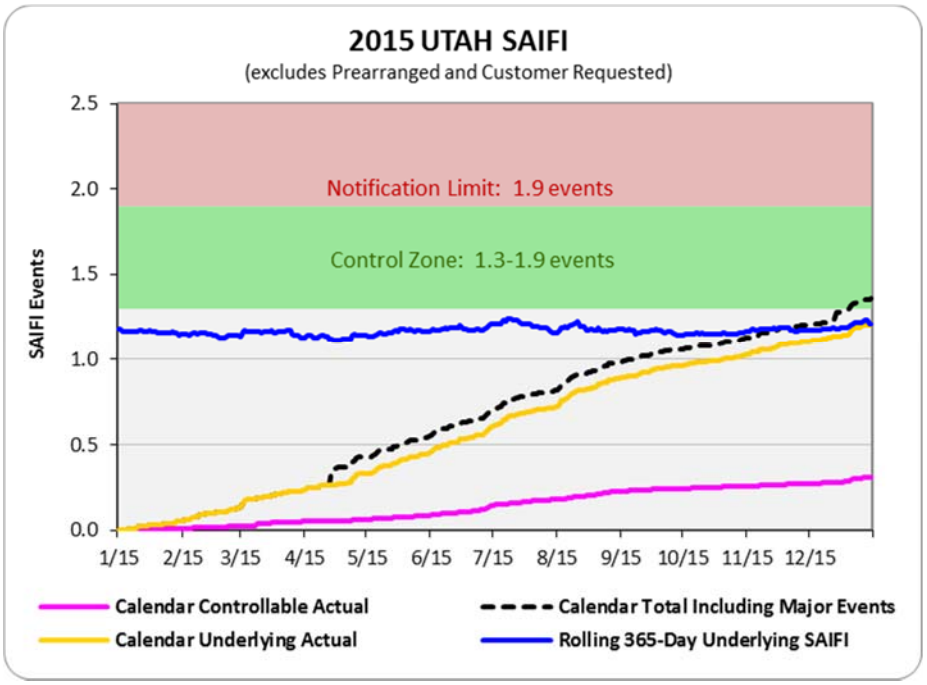
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below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

Utah - SAIDI	January 1 – December 31 , 2015
Total	196
Underlying	154
Controllable Distribution	54



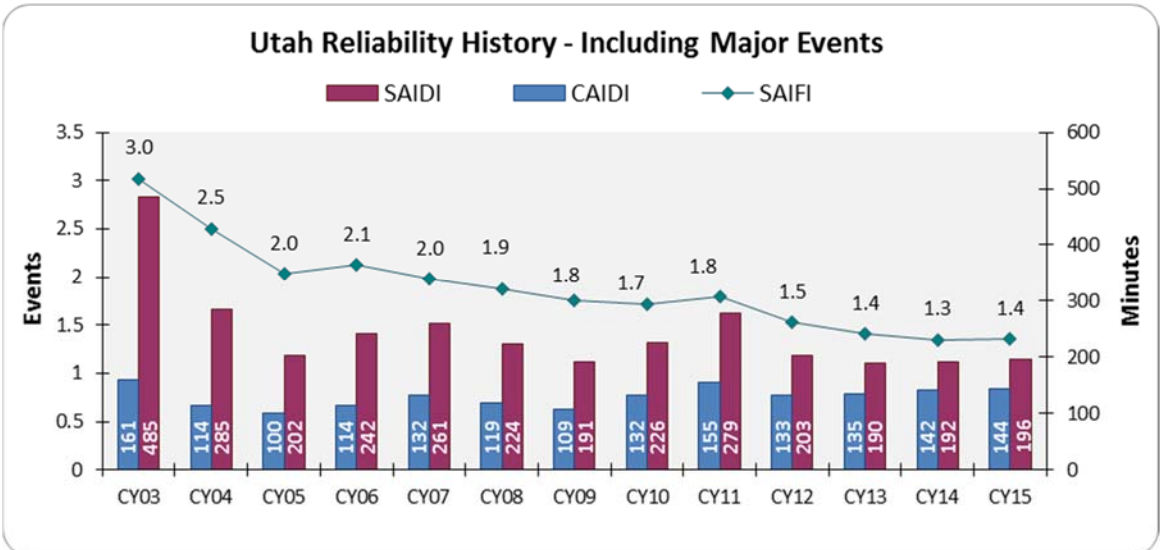
2.2 System Average Interruption Frequency Index (SAIFI)

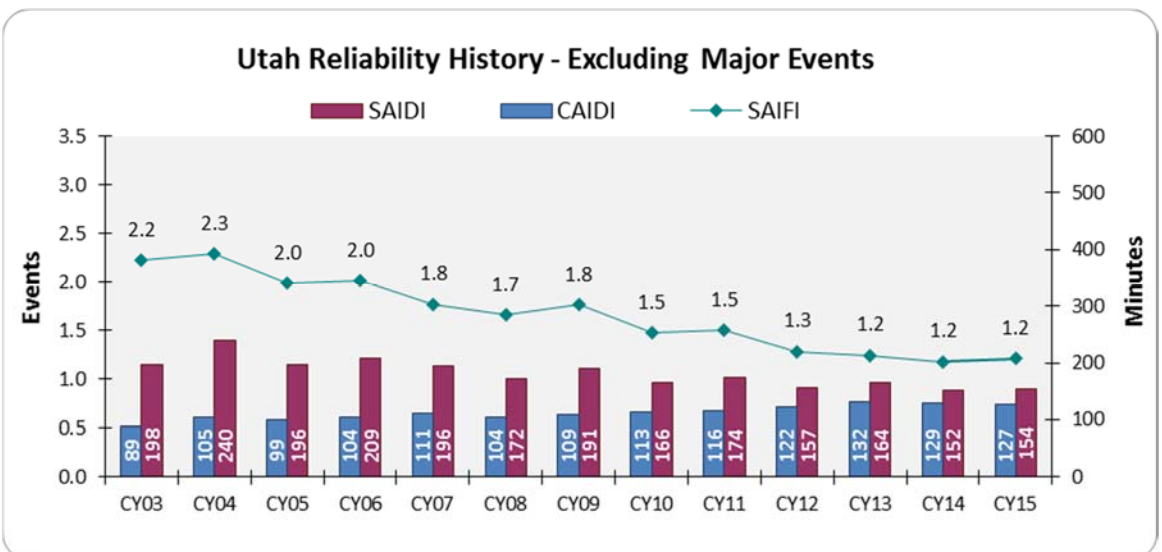
Utah - SAIFI	January 1 – December 31, 2015
Total	1.357
Underlying	1.210
Controllable Distribution	0.310



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. It is particularly noteworthy that these two metrics show 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.

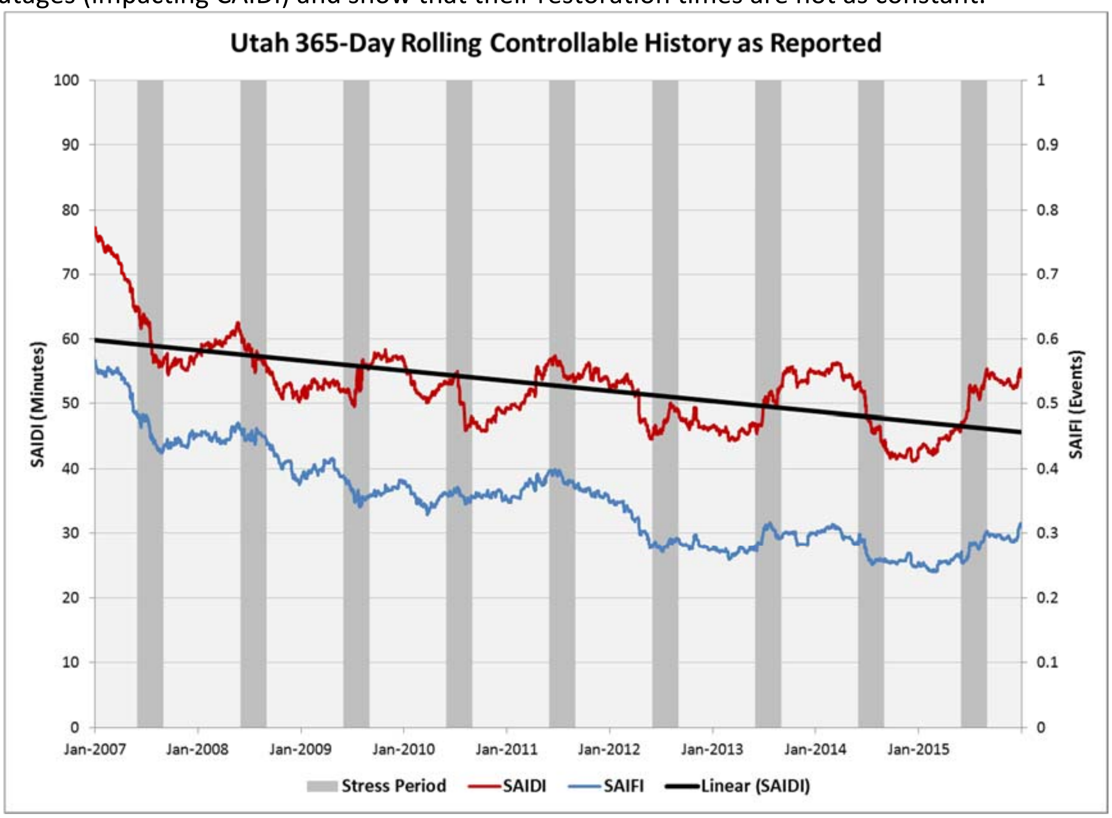




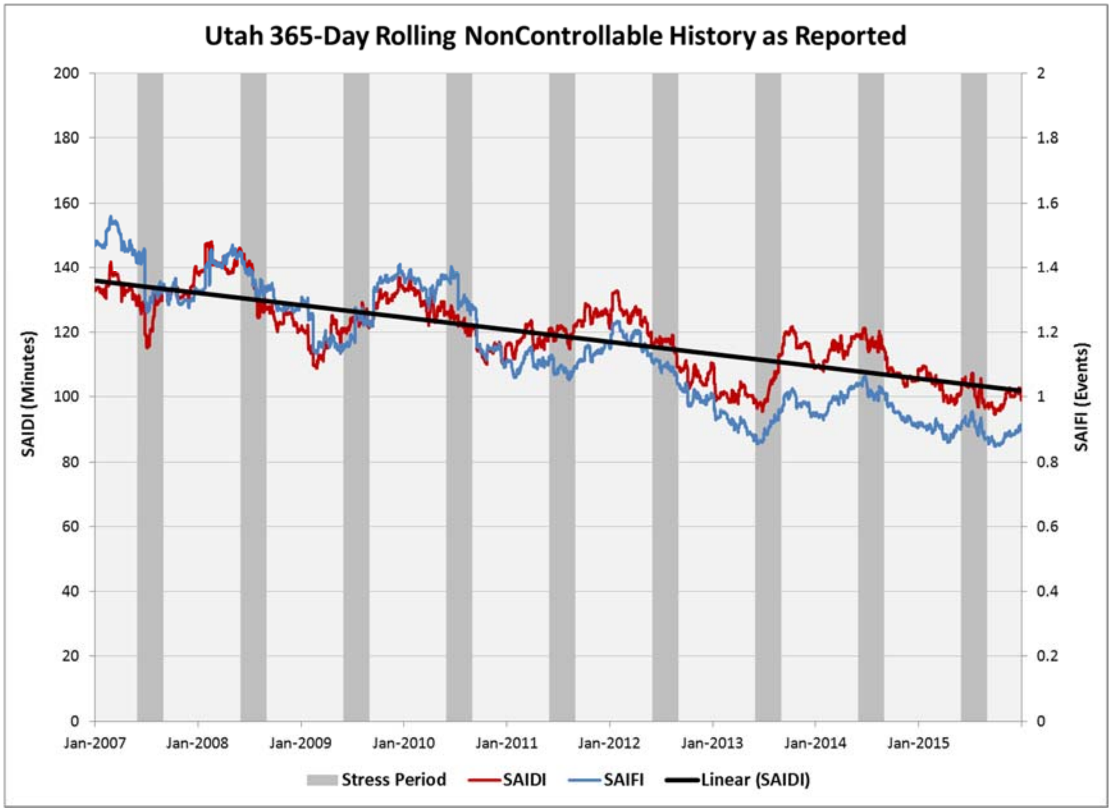
2.4 Controllable, Non-Controllable and Underlying Performance Review

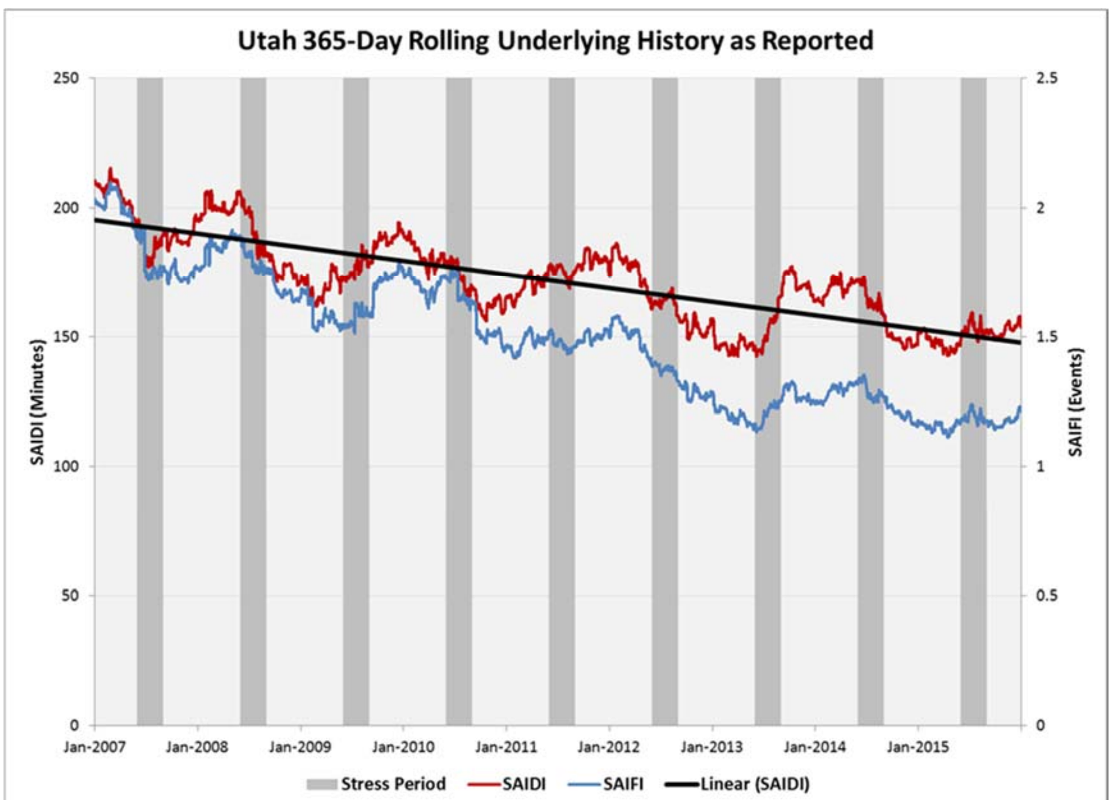
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. This categorization was titled Controllable Distribution outages and recognized that certain types of outages can be cost-effectively 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[4]. 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 longer term general improving trend for all charts. A comparison of the non-controllable SAIDI versus SAIFI results indicate that response to those outages (as measured by CAIDI) is consistent over time, since the SAIDI and SAIFI curves are generally parallel with one another. Controllable outages however, due to their nature (often involving damaged equipment) often result in longer outages (impacting CAIDI) and show that their restoration times are not as constant.



[4] 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)
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
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
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[5] 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 and Customer Notice Given* 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. However, for ease of charting, the pie charts reflect the rollup-level cause category rather than the detail-level direct cause within each category. Therefore, the pie charts for Underlying include prearranged causes (listed within the *planned* category). Following the pie 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 01/01/2015 - 12/31/2015

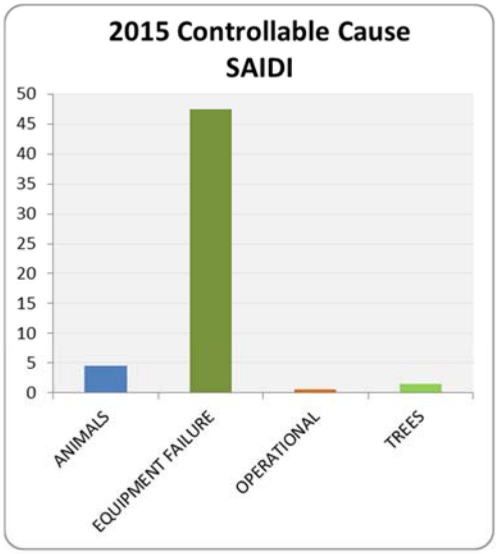
Direct Cause	Customer Minutes Lost for Incident	Customers in Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	1,560,902	10,504	487	1.80	0.012
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,397,250	11,662	354	1.61	0.013
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	312,199	1,992	57	0.36	0.002
BIRD NEST (BMTS)	293,753	1,495	42	0.34	0.002
BIRD SUSPECTED, NO MORTALITY	362,431	3,410	168	0.42	0.004
ANIMALS	**3,926,535**	**29,063**	**1,108**	**4.52**	**0.033**
B/O EQUIPMENT	3,961,559	29,042	624	4.56	0.033
DETERIORATION OR ROTTING	35,426,211	175,569	5,167	40.76	0.202
OVERLOAD	1,841,652	13,895	174	2.12	0.016
RELAYS, BREAKERS, SWITCHES	622	17	41	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	23,581	19	51	0.03	0.000
EQUIPMENT FAILURE	**41,253,625**	**218,542**	**6,057**	**47.47**	**0.251**
FAULTY INSTALL	106,950	964	31	0.12	0.001
IMPROPER PROTECTIVE COORDINATION	169,411	1,883	20	0.19	0.002
INCORRECT RECORDS	55,191	2,592	36	0.06	0.003
INTERNAL CONTRACTOR	1,852	144	4	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	217,150	6,179	23	0.25	0.007
PACIFICORP EMPLOYEE - SUB	0	-	-	-	-
OPERATIONAL	**550,554**	**11,762**	**114**	**0.63**	**0.014**
TREE - TRIMMABLE	1,287,419	10,473	194	1.48	0.012
TREES	**1,287,419**	**10,473**	**194**	**1.48**	**0.012**
Utah Including Prearranged	**47,018,133**	**269,840**	**7,473**	**54.10**	**0.310**

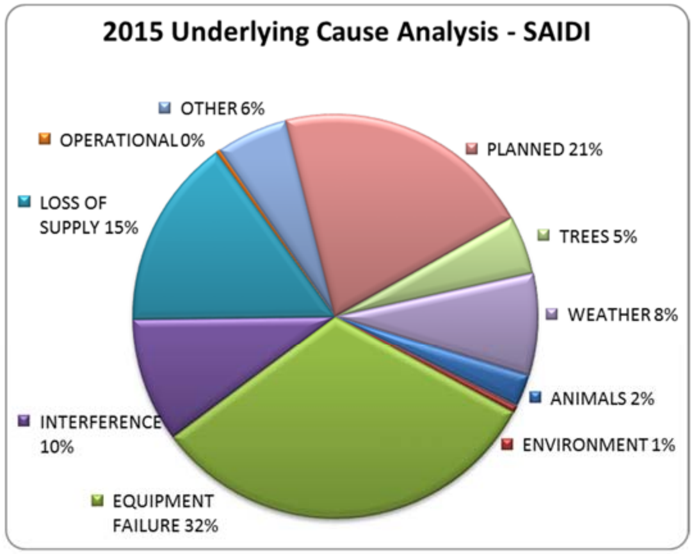
[5] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 869,108 (2015 Utah frozen customer count).

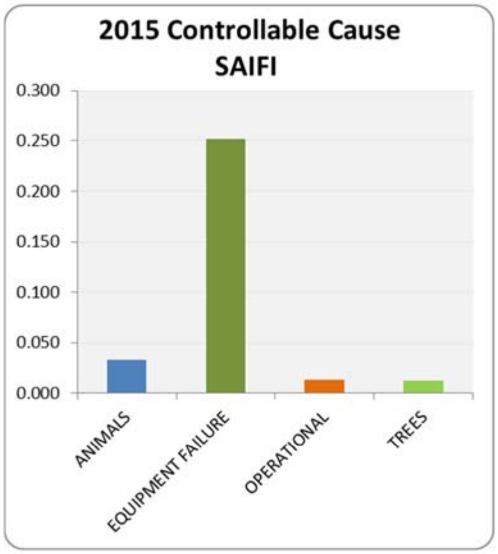
UTAH

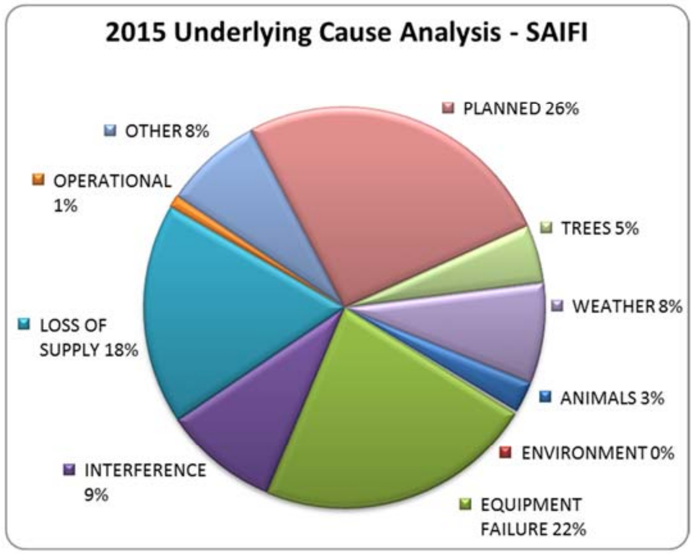
January 1 – December 31, 2015

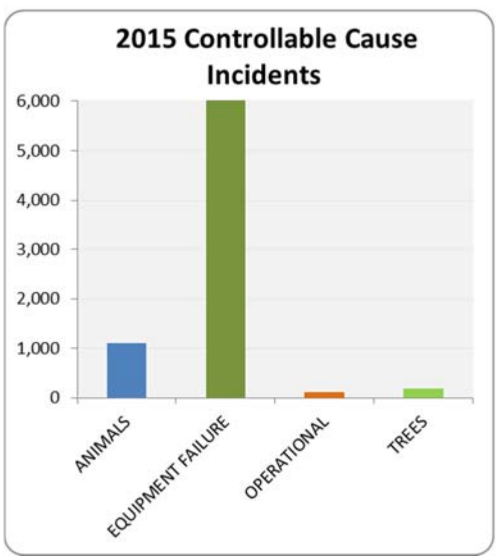
Utah Cause Analysis - Underlying 01/01/2015 - 12/31/2015					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	1,560,902	10,504	487	1.80	0.012
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,397,250	11,662	354	1.61	0.013
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	312,199	1,992	57	0.36	0.002
BIRD NEST (BMTS)	293,753	1,495	42	0.34	0.002
BIRD SUSPECTED, NO MORTALITY	362,431	3,410	168	0.42	0.004
ANIMALS	**3,926,535**	**29,063**	**1,108**	**4.52**	**0.033**
CONDENSATION / MOISTURE	121,914	411	3	0.14	0.000
CONTAMINATION	6,677	64	4	0.01	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	694,173	2,078	36	0.80	0.002
FLOODING	66,210	125	5	0.08	0.000
ENVIRONMENT	**888,974**	**2,678**	**48**	**1.02**	**0.003**
B/O EQUIPMENT	3,961,559	29,042	624	4.56	0.033
DETERIORATION OR ROTTING	35,426,211	175,569	5,167	40.76	0.202
NEARBY FAULT	216,027	2,256	6	0.25	0.003
OVERLOAD	1,841,652	13,895	174	2.12	0.016
POLE FIRE	7,405,355	39,228	254	8.52	0.045
RELAYS, BREAKERS, SWITCHES	622	17	41	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	23,581	19	51	0.03	0.000
EQUIPMENT FAILURE	**48,875,007**	**260,026**	**6,317**	**56.24**	**0.299**
DIG-IN (NON-PACIFICORP PERSONNEL)	2,934,581	18,629	314	3.38	0.021
OTHER INTERFERING OBJECT	820,072	12,016	90	0.94	0.014
OTHER UTILITY/CONTRACTOR	665,112	4,138	97	0.77	0.005
VANDALISM OR THEFT	614,257	5,882	38	0.71	0.007
VEHICLE ACCIDENT	10,260,259	66,714	398	11.81	0.077
INTERFERENCE	**15,294,281**	**107,379**	**937**	**17.60**	**0.124**
FAILURE ON OTHER LINE OR STATION	0	-	4	-	-
LOSS OF FEED FROM SUPPLIER	413	3	2	0.00	0.000
LOSS OF SUBSTATION	3,942,255	37,763	73	4.54	0.043
LOSS OF TRANSMISSION LINE	19,351,777	168,581	354	22.27	0.194
SYSTEM PROTECTION	81	2	5	0.00	0.000
LOSS OF SUPPLY	**23,294,526**	**206,349**	**438**	**26.80**	**0.237**
FAULTY INSTALL	106,950	964	31	0.12	0.001
IMPROPER PROTECTIVE COORDINATION	169,411	1,883	20	0.19	0.002
INCORRECT RECORDS	55,191	2,592	36	0.06	0.003
INTERNAL CONTRACTOR	1,852	144	4	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	217,150	6,179	23	0.25	0.007
PACIFICORP EMPLOYEE - SUB	0	-	-	-	-
OPERATIONAL	**550,554**	**11,762**	**114**	**0.63**	**0.014**
OTHER, KNOWN CAUSE	312,790	2,863	169	0.36	0.003
UNKNOWN	8,416,509	88,916	1,206	9.68	0.102
OTHER	**8,729,299**	**91,779**	**1,375**	**10.04**	**0.106**
CONSTRUCTION	428,170	4,446	312	0.49	0.005
CONSTRUCTION - SCHEDULED SWITGHING	0	-	136	-	-
CUSTOMER NOTICE GIVEN	18,849,161	99,852	2,947	21.69	0.115
CUSTOMER REQUESTED	490,175	7,261	585	0.56	0.008
EMERGENCY DAMAGE REPAIR	11,247,581	167,767	1,508	12.94	0.193
INTENTIONAL TO CLEAR TROUBLE	788,985	22,028	52	0.91	0.025
MAINTENANCE	53	1	240	0.00	0.000
TRANSMISSION REQUESTED	75,986	221	11	0.09	0.000
PLANNED	**31,880,110**	**301,576**	**5,791**	**36.68**	**0.347**
TREE - NON-PREVENTABLE	5,851,744	43,669	468	6.73	0.050
TREE - TRIMMABLE	1,287,419	10,473	194	1.48	0.012
TREES	**7,139,163**	**54,142**	**662**	**8.21**	**0.062**
FREEZING FOG & FROST	11,257	89	2	0.01	0.000
ICE	140,279	29	2	0.16	0.000
LIGHTNING	5,604,389	51,140	596	6.45	0.059
SNOW, SLEET AND BLIZZARD	2,115,838	10,170	208	2.43	0.012
WIND	4,601,317	32,575	334	5.29	0.037
WEATHER	**12,473,080**	**94,003**	**1,142**	**14.35**	**0.108**
	282	1	1	0.00	0.000
	282	**1**	**1**	**0.00**	**0.000**
Utah Including Prearranged	**153,051,813**	**1,158,758**	**17,933**	**176.10**	**1.333**
Utah Excluding Prearranged	**133,712,477**	**1,051,645**	**14,265**	**153.85**	**1.210**

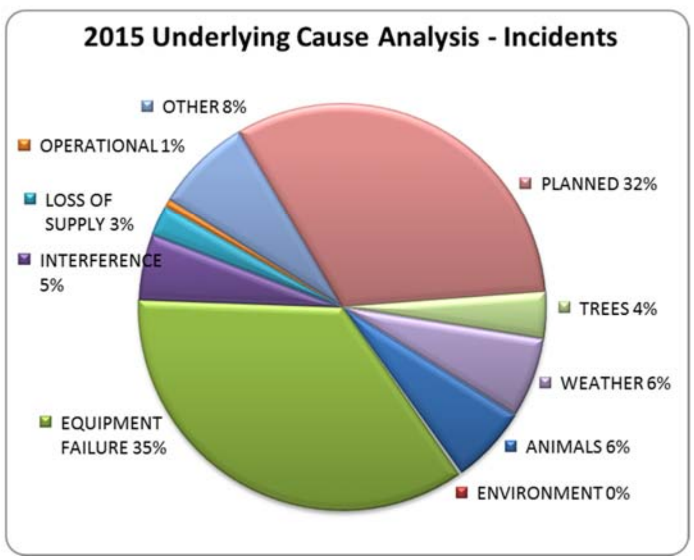

2015 Controllable Cause SAIDI
50
45
40
35
30
25
20
15
10
5
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


2015 Underlying Cause Analysis - SAIDI
OTHER 6%
OPERATIONAL 0%
PLANNED 21%
LOSS OF SUPPLY 15%
TREES 5%
WEATHER 8%
ANIMALS 2%
INTERFERENCE 10%
ENVIRONMENT 1%
EQUIPMENT FAILURE 32%


2015 Controllable Cause SAIFI
0.300
0.250
0.200
0.150
0.100
0.050
0.000
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

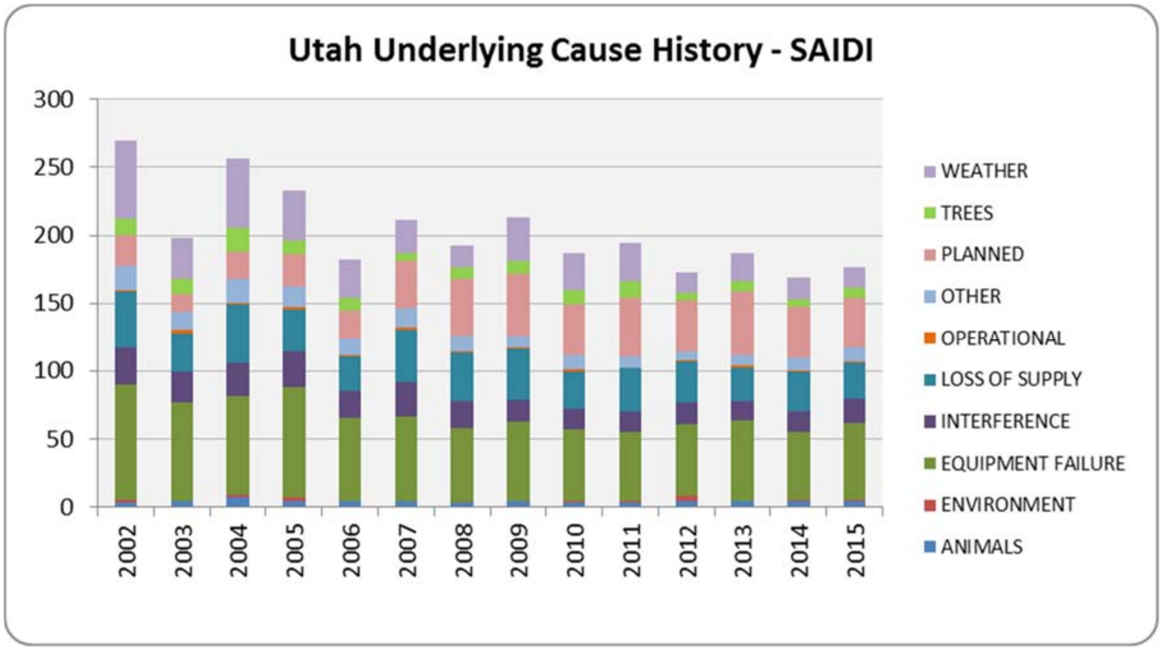

2015 Underlying Cause Analysis - SAIFI
PLANNED 26%
OTHER 8%
OPERATIONAL 1%
TREES 5%
WEATHER 8%
LOSS OF SUPPLY 18%
ANIMALS 3%
ENVIRONMENT 0%
INTERFERENCE 9%
EQUIPMENT FAILURE 22%

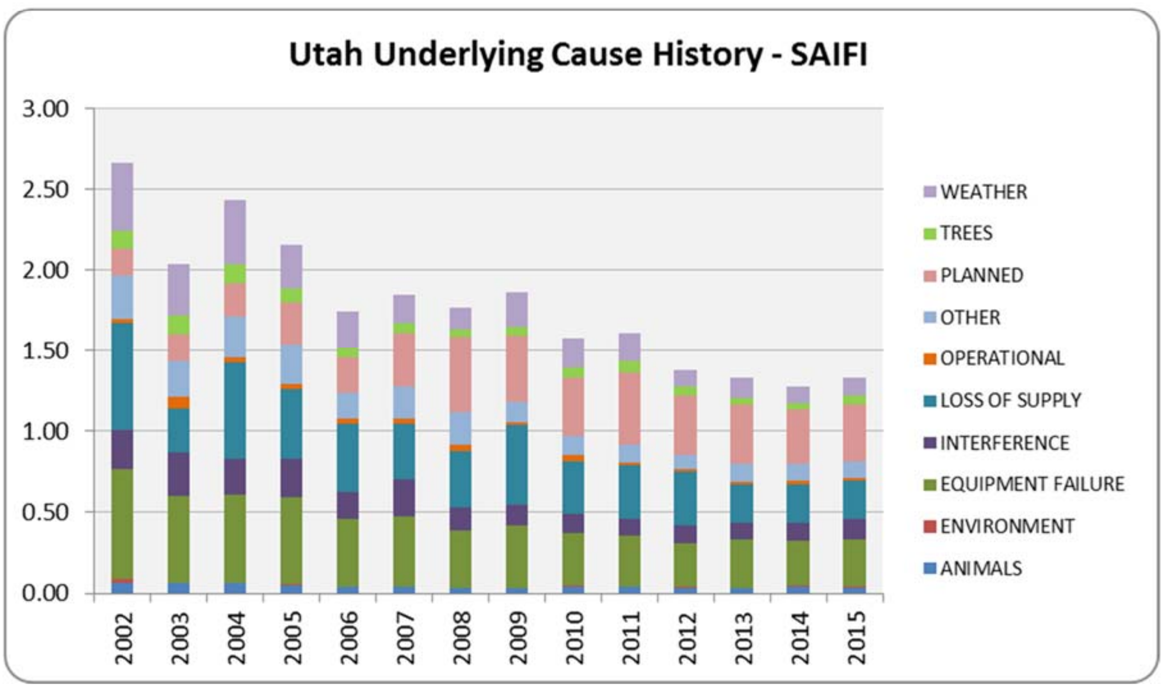

2015 Controllable Cause Incidents
6,000
5,000
4,000
3,000
2,000
1,000
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


2015 Underlying Cause Analysis - Incidents
OTHER 8%
OPERATIONAL 1%
PLANNED 32%
LOSS OF SUPPLY 3%
INTERFERENCE 5%
TREES 4%
WEATHER 6%
EQUIPMENT FAILURE 35%
ANIMALS 6%
ENVIRONMENT 0%

UTAH

January 1 – December 31, 2015





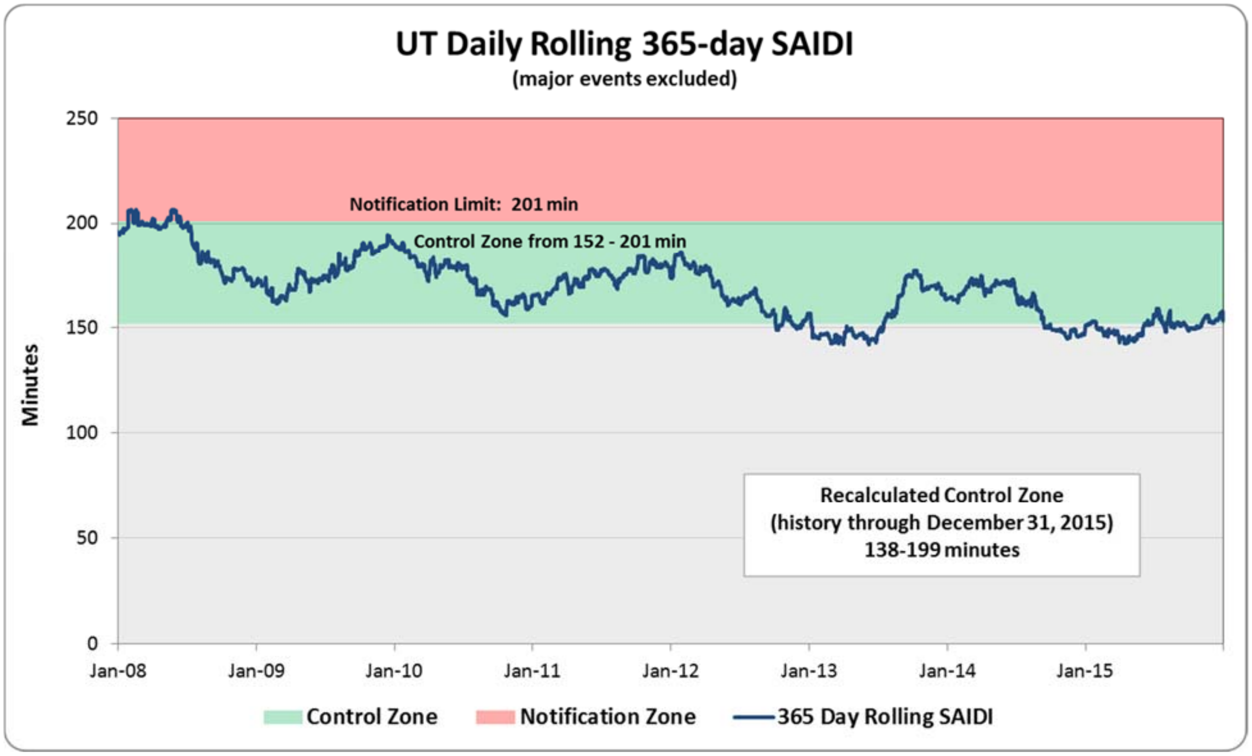
Cause Category	Description and Examples
Environment	Contamination or Airborne Deposit (i.e. salt, trona ash, other chemical dust, sawdust, etc.); corrosive environment; flooding due to rivers, broken water main, etc.; fire/smoke related to forest, brush or building fires (not including fires due to faults or lightning).
Weather	Wind (excluding windborne material); snow, sleet or blizzard; ice; freezing fog; frost; lightning.
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 (i.e. broken conductor hits another line).
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.
Animals and Birds	Any problem nest that requires removal, relocation, trimming, etc; any birds, squirrels or other animals, whether or not remains found.
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.
Loss of Supply	Failure of supply from Generator or Transmission system; failure of distribution substation equipment.
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.
Trees	Growing or falling trees
Other	Cause Unknown; use comments field if there are some possible reasons.

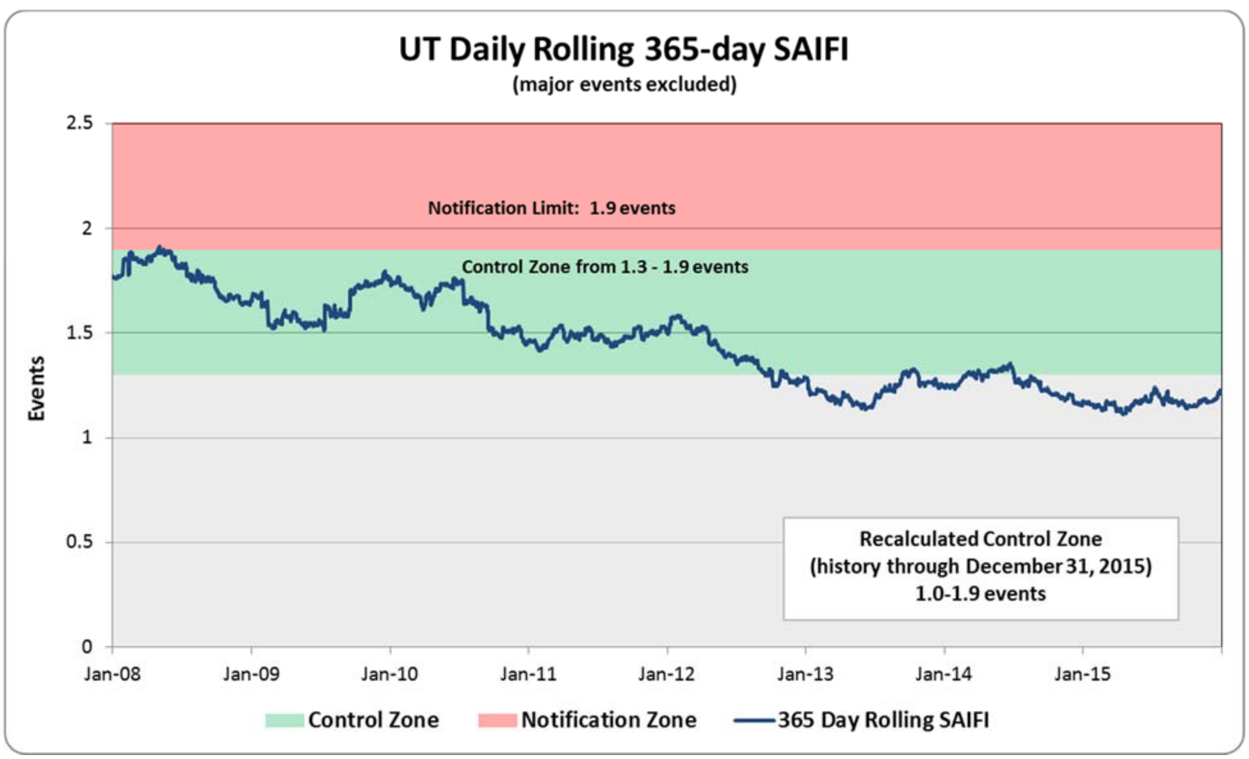
2.6 Baseline Performance

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 this section of the report is updated using the methods that resulted in the approved baselines; refreshing through December 31, 2015 yields the values shown below. In spite of performing this recalculation the Company is not advocating modifications to these baselines.

The Company refreshed the dataset and calculated using the last six years of daily reliability data, which was selected to align with major event calculations, but required the addition of the prior 365 days in order to construct the daily rolling 365-days curves used for these calculations. The 365-day average performance was 176 minutes and 1.59 events. The baselines filed were based on a 95% probability and resulted in a SAIDI range of 152-201 minutes and a SAIFI range of 1.3-1.9 events. The same methods applied through December 31, 2015 result in an average of 157 minutes and 1.21 events, with a SAIDI range of 144-192 minutes and a SAIFI range of 1.1-1.8 events. These values are shown in the table below.

	SAIDI (Minutes)			SAIFI (Events)		
	Average	Lower Value Control Zone	Upper Value Control Zone	Average	Lower Value Control Zone	Upper Value Control Zone
As Filed	176	152	201	1.59	1.3	1.9
Recalculated through December 31, 2015	169	138	199	1.45	1.0	1.9
Current Period (January 1-December 31, 2015)	151	143	158	1.17	1.12	1.22


UT Daily Rolling 365-day SAIDI
(major events excluded)
Notification Limit: 201 min
Control Zone from 152 - 201 min
Minutes
250
200
150
100
50
0
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Recalculated Control Zone
(history through December 31, 2015)
138-199 minutes
Control Zone
Notification Zone
365 Day Rolling SAIDI


UT Daily Rolling 365-day SAIFI
(major events excluded)
Notification Limit: 1.9 events
Control Zone from 1.3 - 1.9 events
Events
2.5
2
1.5
1
0.5
0
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Recalculated Control Zone
(history through December 31, 2015)
1.0-1.9 events
Control Zone
Notification Zone
365 Day Rolling SAIFI

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

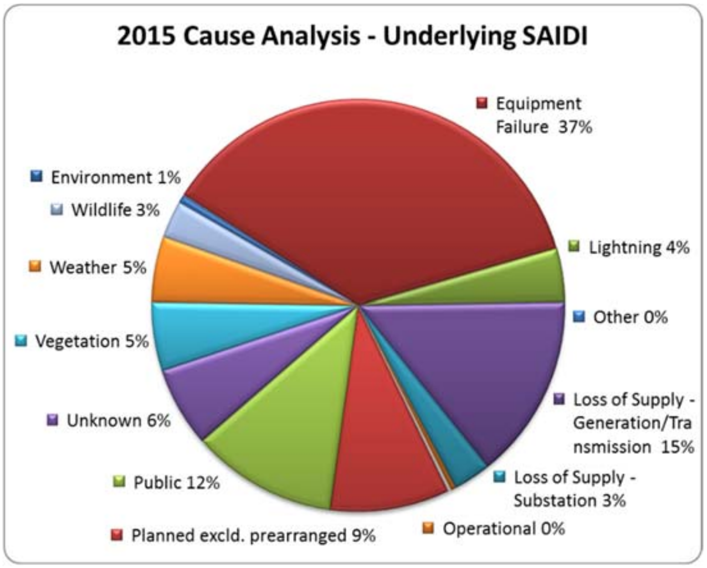
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Rule R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least 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.

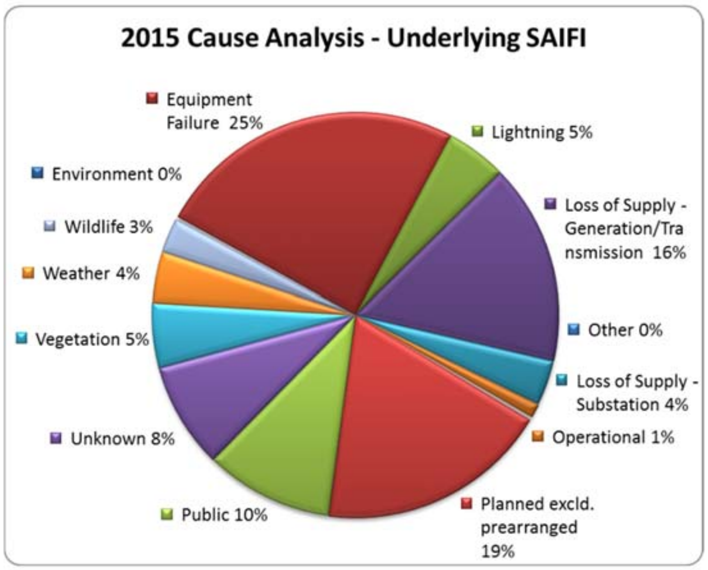
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$ are required.

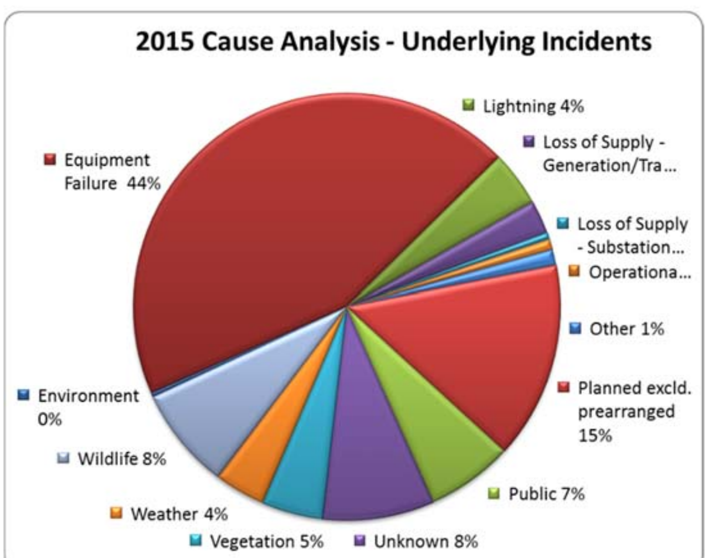
Major Events and Prearranged Excluded*	2011				2012				2013				2014				2015			
STATE	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**
Utah	174	1.5	116	1.10	157	1.3	122	0.72	164	1.2	132	0.81	152	1.2	129	1.21	154	1.2	127	1.48
OP AREA																				
AMERICAN FORK	132	1.3	106		101	0.8	135		126	1.3	99		113	1.0	109		134	1.1	128	
CEDAR CITY	218	1.7	131		279	1.8	154		225	1.8	127		170	1.1	151		238	1.6	146	
CEDAR CITY (MILFORD)	980	8.1	121		363	2.8	129		707	3.3	213		891	3.3	271		334	3.6	92	
JORDAN VALLEY	113	0.9	121		106	0.8	129		106	0.7	145		103	0.7	141		128	1.0	126	
LAYTON	155	1.3	124		105	0.8	131		105	1.0	109		108	0.8	127		122	1.1	109	
MOAB	151	1.8	86		375	3.1	122		284	1.9	147		412	2.3	181		426	3.5	122	
OGDEN	204	1.8	116		153	1.3	117		168	1.4	122		218	1.9	113		175	1.4	123	
PARK CITY	186	1.6	116		184	1.8	100		232	1.5	155		147	1.1	140		247	1.5	162	
PRICE	421	2.5	166		133	1.4	97		514	1.8	293		394	2.2	180		230	1.8	127	
RICHFIELD	369	3.2	114		200	2.0	100		469	3.4	138		181	1.7	104		303	2.2	137	
RICHFIELD (DELTA)	316	3.6	89		329	2.9	113		316	3.7	85		202	1.9	108		536	3.0	180	
SLC METRO	178	1.5	117		129	1.2	112		170	1.2	139		145	1.1	129		107	0.9	125	
SMITHFIELD	174	1.6	106		267	2.6	102		81	0.7	117		114	0.9	126		236	1.6	150	
TOOELE	329	3.0	110		595	3.7	163		137	1.3	103		239	2.1	115		129	1.3	103	
TREMONTON	255	2.2	115		447	3.0	147		335	3.3	102		216	2.0	111		462	4.2	110	
VERNAL	117	2.2	54		236	2.9	82		160	2.1	75		119	1.2	101		68	0.8	87	

* except MAIFIe

Utah Cause Category	2011		2012		2013		2014		2015	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	0	0.0	4	0.0	0	0.0	1	0.0	1	0.0
Equipment Failure	52	0.3	53	0.3	60	0.3	51	0.3	56	0.3
Lightning	9	0.1	4	0.0	9	0.1	7	0.1	6	0.1
Loss of Supply - Generation/Transmission	26	0.3	25	0.3	19	0.2	23	0.2	22	0.2
Loss of Supply - Substation	6	0.1	5	0.1	6	0.0	6	0.0	5	0.0
Operational	1	0.0	0	0.0	1	0.0	1	0.0	1	0.0
Other	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	23	0.3	22	0.3	24	0.3	20	0.2	14	0.2
Public	15	0.1	16	0.1	14	0.1	15	0.1	18	0.1
Unknown	7	0.1	7	0.1	8	0.1	10	0.1	10	0.1
Vegetation	13	0.1	5	0.1	7	0.0	6	0.0	8	0.1
Weather	19	0.1	11	0.1	12	0.1	8	0.0	8	0.0
Wildlife	4	0.0	4	0.0	4	0.0	4	0.0	5	0.0
UTAH Underlying	**174**	**1.5**	**157**	**1.3**	**164**	**1.2**	**151**	**1.2**	**154**	**1.2**


2015 Cause Analysis - Underlying SAIDI
Equipment Failure 37%
Environment 1%
Wildlife 3%
Weather 5%
Vegetation 5%
Unknown 6%
Public 12%
Planned excld. prearranged 9%
Operational 0%
Loss of Supply - Substation 3%
Loss of Supply - Generation/Transmission 15%
Other 0%
Lightning 4%


2015 Cause Analysis - Underlying SAIFI
Equipment Failure 25%
Lightning 5%
Environment 0%
Wildlife 3%
Weather 4%
Vegetation 5%
Unknown 8%
Public 10%
Planned excld. prearranged 19%
Operational 1%
Loss of Supply - Substation 4%
Other 0%
Loss of Supply - Generation/Transmission 16%


2015 Cause Analysis - Underlying Incidents
Lightning 4%
Loss of Supply - Generation/Tra...
Equipment Failure 44%
Loss of Supply - Substation...
Operationa...
Other 1%
Planned excld. prearranged 15%
Environment 0%
Wildlife 8%
Public 7%
Weather 4%
Vegetation 5%
Unknown 8%

2.8 Reduce CPI for Worst Performing Circuits by 20%

On a routine basis, the Company reviews circuits for performance. One of the measures that it uses is called circuit performance indicator (CPI)[6], which is 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 selects a set of Worst Performing Circuits for improvements, which are to be completed within two years of selection. Within five years of selection, the average performance of the five-selection set must improve by at least 20% (as measured by comparing current performance against baseline performance).

2.8.1 Circuit Performance Score Updates for Prior-Year Selections

Annually, the company tracks 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[7]	Performance 12/31/2015
Program Year 16: (CY2015)			
Nibley 21	IN PROGRESS	179	196
Brighton 12	COMPLETE	270	239
Rattlesnake 22	IN PROGRESS	456	349
Decker Lake 12	COMPLETE	167	162
Toquerville 31	IN PROGRESS	475	421
TARGET SCORE = **248**		**309**	**273**
Program Year 15: (CY2014)			
Skull Valley 11	COMPLETE	468	382
Fort Douglas 13	COMPLETE	417	184
Parowan Valley 25	COMPLETE	408	411
Brighton 21	COMPLETE	364	237
Bush 12	COMPLETE	281	221
TARGET SCORE = **248**		**310**	**287**
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	53
Eden 11	COMPLETE	116	226
Bush 11	COMPLETE	228	213
Pioneer 12	COMPLETE	177	58
Grantsville 12	COMPLETE	250	148
TARGET SCORE = 108		**135**	**140**

[6] CPI is a blended metric used to identify circuit level underperformance. The equation that blends reliability metrics is detailed on page 36.

[7] 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.

Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	325
East Bench 12	COMPLETE	112	45
Clinton 11	COMPLETE	133	35
Redwood 16	COMPLETE	145	45
Orangeville 11	COMPLETE	114	18
TARGET SCORE = **114**	**Target Met**	**142**	**94**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	52
Huntington City 12	COMPLETE	285	64
Magna 15	COMPLETE	140	53
Gunnison 12	COMPLETE	110	70
Capitol 11	COMPLETE	129	74
TARGET SCORE = **134**	**Target Met**	**167**	**63**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	162
North Bench 13	COMPLETE	95	58
Newgate 14	COMPLETE	164	75
Newton 12	COMPLETE	105	84
St Johns 11	COMPLETE	547	300
TARGET SCORE = **162**	**Target Met**	**203**	**136**
Program Year 10: (CY2009			
Fruit Heights 12	COMPLETE	113	77
Mathis 12	COMPLETE	132	89
Parrish 11	COMPLETE	137	61
Valley Center 11	COMPLETE	169	38
Hammer 15	COMPLETE	95	48
TARGET SCORE = **104**	**Target Met**	**129**	**63**

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					
CUMULATIVE January – December 2015 = 81%					
January	February	March	April	May	June
90%	91%	87%	91%	80%	73%
July	August	September	October	November	December
77%	74%	83%	83%	78%	84%

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.

2015 CAIDI (Average Outage Duration)	
Underlying Performance	127 minutes
Total Performance	144 minutes

2.11 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	80%
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[8] complaints within 30 days	100%	100%

[8] 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.

In 2015, there were six dates identified as a wide-scale outage days; call statistics are shown in the table below. The outage event on January 29, 2015 was a Loss of supply at the Granger substation in Utah, resulting in approximately 9,100 customers out of service for approximately one hour. The outage events on February 9, 2015 were due to a winter storm which affected customers in Wyoming, California, Oregon, and Washington, and met major event thresholds for Wyoming, California, and Oregon. On April 21, 2015 a loss of supply event in Oregon caused an eight minute outage to 29,258 customers. On August 3, 2015 Park City, Jordan Valley, and Salt Lake City, Utah, experienced a loss of supply event when a flash-over occurred on the transmission line, impacting 12,675 customers with restorations ranging from three to seven hours. On October 5, 2015, Yakima, Washington experienced a SAIFI-based major event when a loss of supply event affected 13,813 customers for one hour. On November 3, 2015 Mt. Shasta, California experienced a loss of supply event affecting 3,141 customers for between one and two hours, and Salt Lake City also experienced an unknown outage, suspected to be weather-related; impacting 4,178 customers for two hours.

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
1/29/2015	15:00	15:14	1262	216	61	530	89
	15:15	15:29	1195	101	19	221	62
	15:30	15:44	834	0	11	99	19
	15:45	15:59	714	2	1	63	10
2/9/2015	10:30	10:44	541	0	7	149	61
	10:45	10:59	924	74	17	123	51
	11:00	11:14	2094	256	20	160	70
	11:15	11:29	1224	35	71	740	128
	11:30	11:44	976	0	59	414	66
	11:45	11:59	849	0	2	44	5
	12:00	12:14	991	0	1	68	8
	12:15	12:29	1050	1	1	70	8
	12:30	12:44	960	0	0	56	8
	12:45	12:59	1037	3	3	86	8
	13:00	13:14	990	2	2	34	3
	13:15	13:29	966	0	6	151	13
	13:30	13:44	846	0	7	148	19
	13:45	13:59	794	0	9	84	18
	14:00	14:14	1239	0	20	189	51
	14:15	14:29	1525	0	10	134	31
	14:30	14:44	1990	94	15	223	43
	14:45	14:59	1431	32	28	212	60
	15:00	15:14	1292	17	32	233	60
	15:15	15:29	1429	9	10	132	23
	15:30	15:44	1422	0	15	139	32
	15:45	15:59	1091	49	20	227	52
	16:00	16:14	936	11	7	226	24
	16:15	16:29	1112	126	24	224	68

4/21/2015	15:30	15:44	2510	287	290	433	59
	15:45	15:59	465	0	8	172	29
	16:00	16:14	395	0	7	174	71
	16:15	16:29	394	0	13	136	50
8/3/2015	16:00	16:14	531	0	2	62	15
	16:15	16:29	498	0	5	114	47
	16:30	16:44	548	0	6	111	60
	16:45	16:59	1576	240	67	472	85
10/5/2015	10:15	10:29	526	0	11	142	85
	10:30	10:44	523	0	5	103	38
	10:45	10:59	510	1	29	592	80
	11:00	11:14	3291	538	184	587	90
	11:15	11:29	1133	0	9	94	21
	11:30	11:44	829	3	9	212	40
	11:45	11:59	742	0	27	186	86
	12:00	12:14	545	0	11	122	42
11/3/2015	10:30	10:44	558	0	73	321	165
	10:45	10:59	661	0	33	220	73
	11:00	11:14	813	46	18	205	71
	11:15	11:29	955	42	11	142	31
	11:30	11:44	769	0	10	52	11
	11:45	11:59	676	0	4	52	12
	12:00	12:14	611	0	1	151	15
	12:15	12:29	567	0	3	52	9

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

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

customer*guarantees*

January to December 2015

Utah

		2015				2014			
	Description	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1	Restoring Supply	1,051,644	1	100.00%	$75	1,017,071	0	100%	$0
CG2	Appointments	7,357	6	99.92%	$300	7,115	26	99.63%	$1,300
CG3	Switching on Power	7,068	4	99.94%	$200	8,134	2	99.98%	$100
CG4	Estimates	1,304	10	99.23%	$500	1,263	5	99.60%	$250
CG5	Respond to Billing Inquiries	1,743	9	99.48%	$450	1,808	3	99.83%	$150
CG6	Respond to Meter Problems	869	1	99.88%	$50	978	0	100%	$0
CG7	Notification of Planned Interruptions	99,852	43	99.96%	$2,150	86,658	79	99.91%	$3,950
		1,169,837	**74**	**99.99%**	**$3,725**	**1,123,027**	**115**	**99.99%**	**$5,750**

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[9], 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.[10]
- 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

[9] 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.

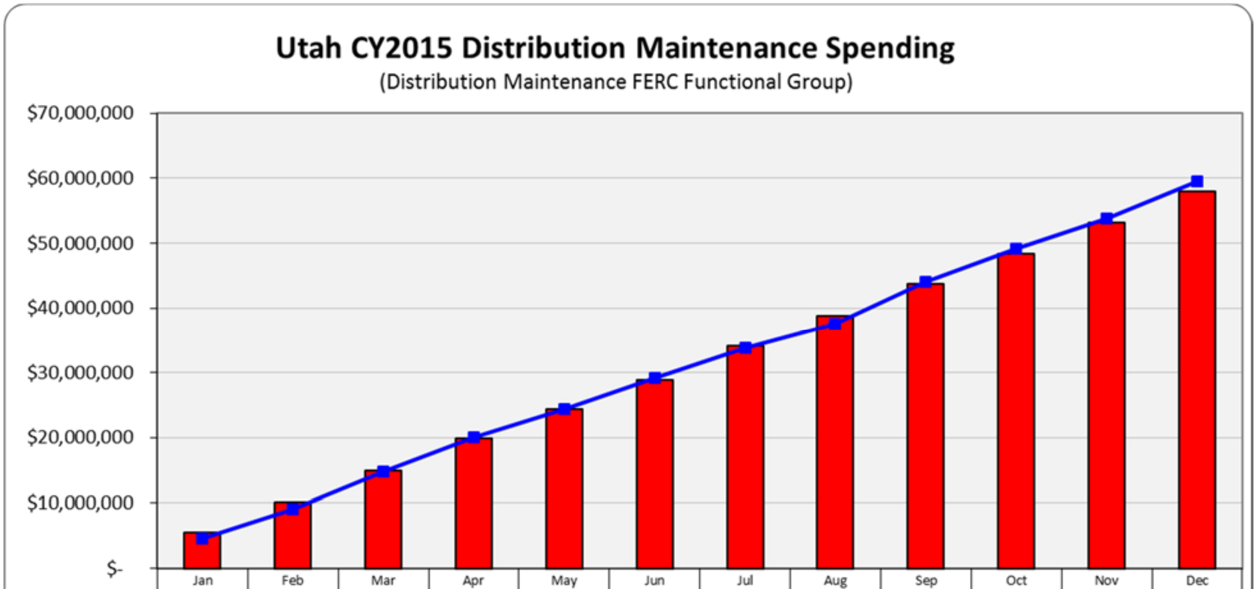
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

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.

[10] 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.

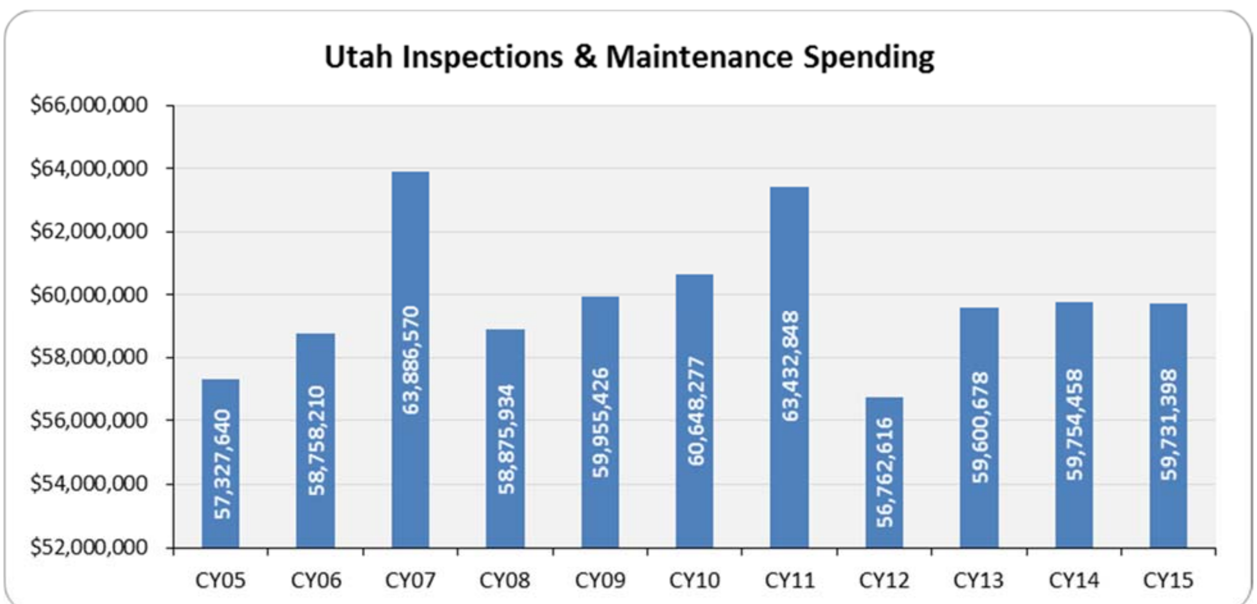
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending [11]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,564,355	$10,072,615	$14,964,978	$19,878,075	$24,372,257	$28,900,729	$34,135,921	$38,721,204	$43,670,616	$48,420,725	$53,189,196	$57,946,129
Actual	$4,598,421	$9,108,312	$14,741,711	$20,110,720	$24,427,827	$29,227,482	$33,885,221	$37,523,408	$44,007,056	$49,067,562	$53,795,282	$59,431,398

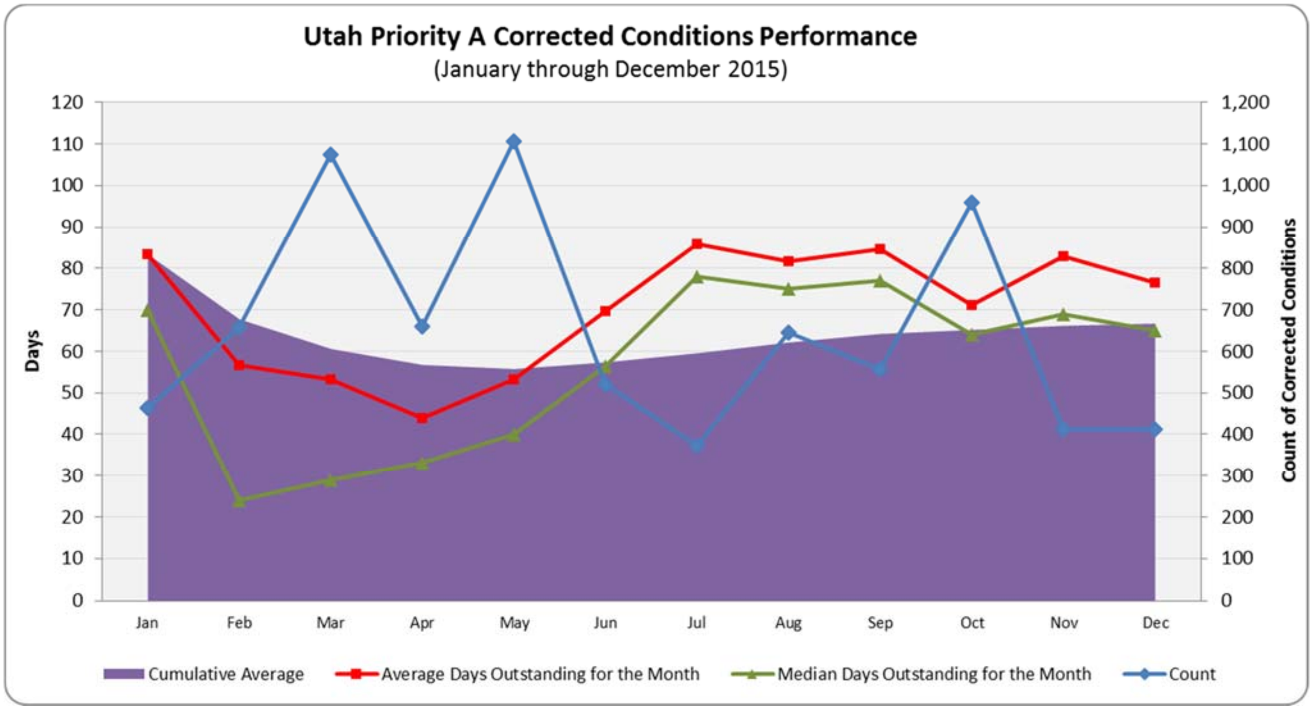
3.2.1 Maintenance Historical Spending



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

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.



Oldest Outstanding Priority A Conditions In Utah

District	Mapstring	Pole	Condition	Inspection Remarks	Inspection Date	Completion Date	Days to Correct	Circuit	Explanation
Ogden	11205001	169205	BOPADV LT	VAULT WILL NOT LOCK	1/17/2015	2/9/2016	388	UIN11	The "A" condition was an unsecurable vault lid. The lid couldn't be repaired, requiring us to replace the vault with a ground sleeve. The vault was on a radial feed, so we decided it was in our best interest to close the loop, to eliminate an outage to several hundred customers. We replaced the "A" condition vault as soon as the work to close the loop was complete.

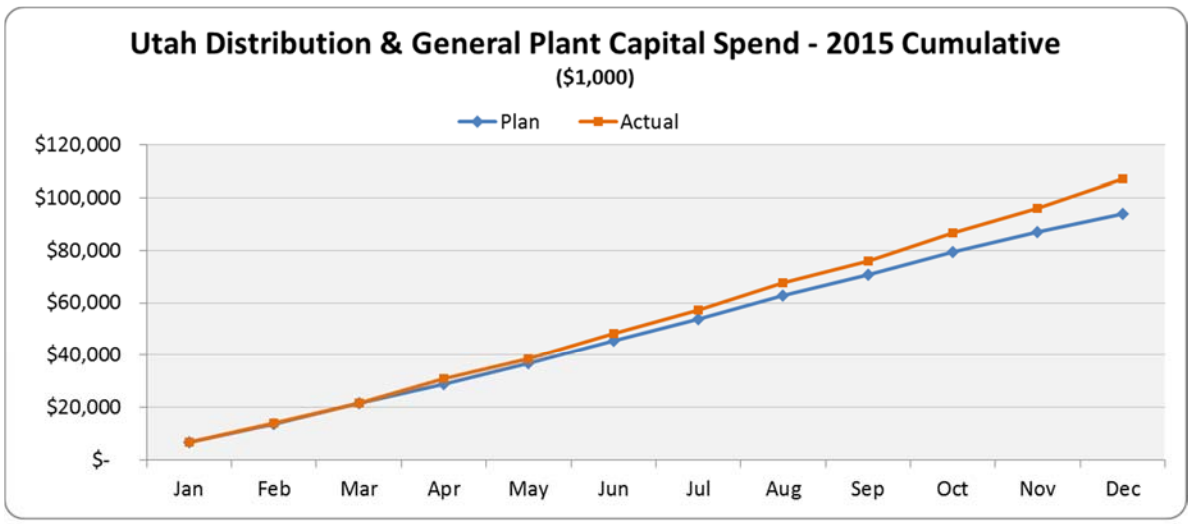
Metro	11401001	227700	CLEAR	DRIPLOOP < 18"/12" & REACHABLE F/GRND-LOW SVC OV ROOF_REACHABL2	1/27/2015	2/4/2016	373	EMI11	This pole sat between two garages with no access. We tried working with the property owner to get the pole out between the garages as they were causing minor damage to the eave and awning. After many months, we were unable to get the necessary right-of-way to relocate the pole, so it had to be replaced in place.
Metro	11401001	227700	BOPOLE	DECAY REJECT REPLACE_EXPA 1.5X4.5 1.5X4.5_EXPOSED POCKETS ABOVE					
American Fork	11408003	12103	BOPOLE	DECAY REJECT RESTORE_SR 0.88_UNSTABLE	2/3/2015	1/14/2016	345	MAP11	Mapleton City was working on a trail, which required us to relocate our poles. The pole in question was part of this job and it didn’t make sense to change out the pole and relocate it again. The city had some right-of-way issues with some customers which held up the job. Once they got approval, we moved forward with the project and replaced the pole.
Moab	11426022	228800	BOPOLE	DECAY REJECT REPLACE_EXPA 6067425	5/14/2015	1/5/2016	236	SPA12	The pole was located on the Moab golf course fairway; the golf course superintendent would not allow use to access the pole with our equipment until the golf course was closed and the ground was frozen.
Moab	11426022	228800	BOGRD BND	BROKEN OR MISSING GROUND_@GL 6067425					

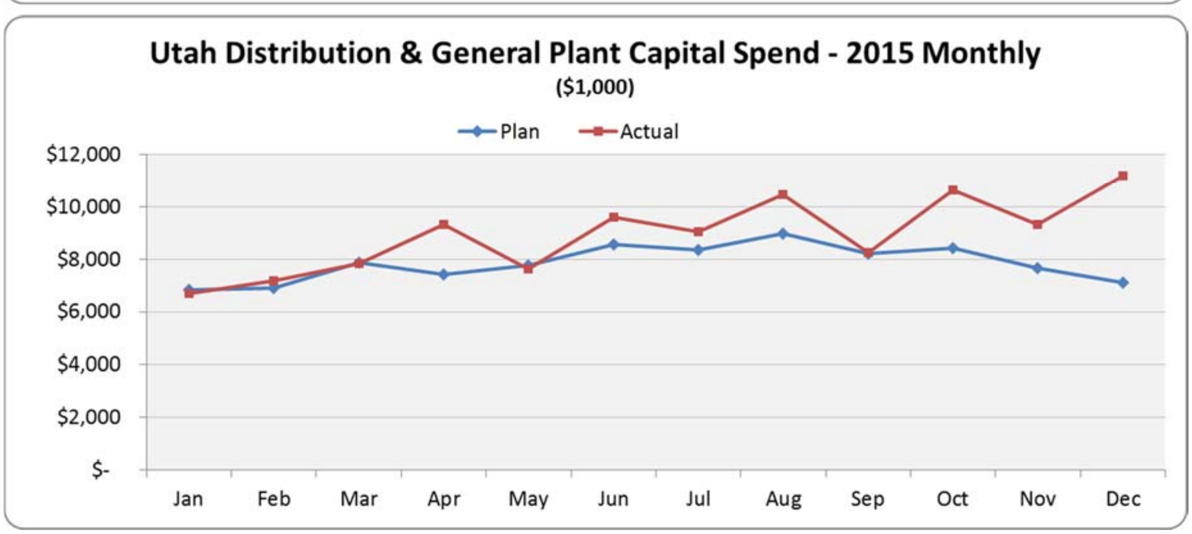
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January – December 2015

	Investment	Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	$8.6	$7.7	
2.	New Connect	$45.2	$41.3	Commercial new connects over plan, (+$4.1M).
3.	System Reinforcement	$7.9	$6.5	Feeder reinforcements over plan, (+$1.5M).
4.	Replacement	$41.7	$35.1	Replacements for underground distribution vaults/ equipment, overhead distribution poles, customer meters, and vehicles (transport) over plan, (+$8.1M); replacements for overhead distribution lines/other under plan, (-$1.3M).
5.	Upgrade & Modernize	$3.9	$3.5	
	Total	**$107.2**	**$94.1**	



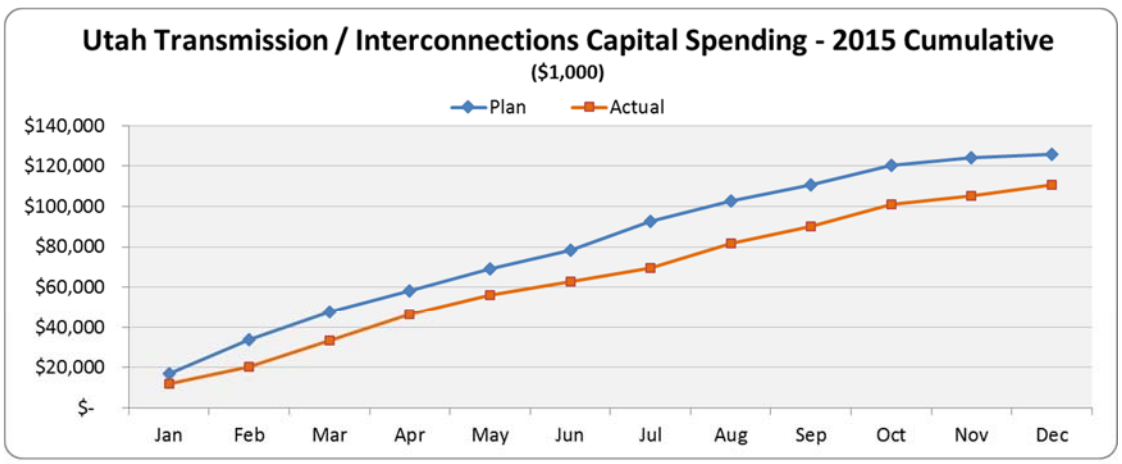


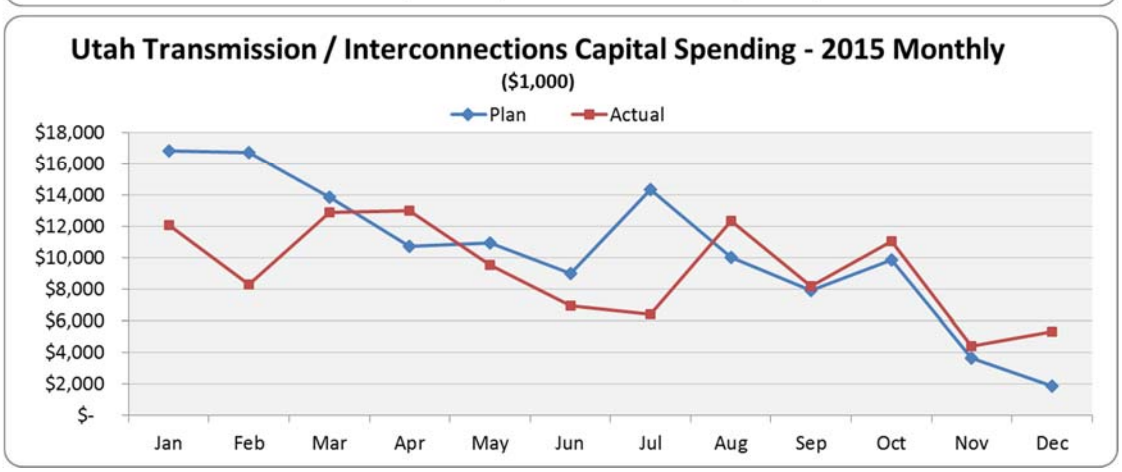
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January –December 2015

	Investment	Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	10.3	6.0	Mandated NERC reliability over plan, (+$4.6M); mandated right-of-way renewals under plan, (-$1.0M).
2.	New Connect	0.3	0.5	
3.	Local Transmission System Reinforcements	28.6	31.8	Local sub-transmission line reinforcement under plan, (-$3.9M).
**4.	Main Grid Reinforcements / Interconnections	26.9	32.4	Pinto 3rd Phase Shifting Transformer (-$2.4M), Holden Irrigation-Fillmore Rebuild (-$1.5M), and Purgatory Flat New 138kV (-$1.2M), under plan.
**5.	Energy Gateway Transmission	29.5	40.2	Sigurd Red Butte Crystal 345kV Line (-$11.4M) under plan.
6.	Replacement	14.6	14.7	Replacements for local overhead transmission lines/other over plan, (+$1.5M); replacements for local transmission overhead poles and substation switchgear/breakers/reclosers under plan, (-$2.5M).
7.	Upgrade & Modernize	0.6	0.5	
	Total	**110.8**	**126.0**	





*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

	2014	2015																	
	Jan - Dec 2014	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jan - Jun	Jul	Aug	Sep	Q3 Total	Oct	Nov	Dec	Q4 Total	Jan-Dec
Residential																			
UT South	696	44	52	42	138	57	69	76	202	340	71	64	128	263	70	70	58	198	801
UT North/Metro	4,091	314	195	230	739	301	473	388	1,162	1,901	444	462	281	1,187	506	333	287	1,126	4,214
UT Central	6,999	620	528	853	2,001	524	612	818	1,954	3,955	965	1,094	635	2,694	944	876	594	2,414	9,063
Total Residential	**11,786**	**978**	**775**	**1,125**	**2,878**	**882**	**1,154**	**1,282**	**3,318**	**6,196**	**1,480**	**1,620**	**1,044**	**4,144**	**1,520**	**1,279**	**939**	**3,738**	**14,078**
					-				-	-				-				-	-
Commercial					-				-	-				-				-	-
UT South	176	16	16	16	48	16	13	26	55	103	22	33	22	77	18	14	30	62	242
UT North/Metro	559	67	44	41	152	54	29	51	134	286	57	68	58	183	70	76	60	206	675
UT Central	627	54	33	67	154	73	67	71	211	365	62	67	49	178	107	93	64	264	807
Total Commercial	**1,362**	**137**	**93**	**124**	**354**	**143**	**109**	**148**	**400**	**754**	**141**	**168**	**129**	**438**	**195**	**183**	**154**	**532**	**1,724**
					-				-	-				-				-	-
Industrial					-				-	-				-				-	-
UT South	3	-	-	1	1	-	-	-	-	1	2	-	-	2	-	1	-	1	4
UT North/Metro	2	2	-	-	2	1	-	-	1	3	-	-	-	-	-	-	2	2	5
UT Central	9	-	-	1	1	1	-	-	1	2	-	-	-	-	-	-	-	-	2
Total Industrial	**14**	**2**	**-**	**2**	**4**	**2**	**-**	**-**	**2**	**6**	**2**	**-**	**-**	**2**	**-**	**1**	**2**	**3**	**11**
					-				-	-				-				-	-
Irrigation					-				-	-				-				-	-
UT South	45	2	3	3	8	13	6	3	22	30	5	-	-	5	1	3	1	5	40
UT North/Metro	3	-	2	1	3	-	1	3	4	7	2	-	-	2	1	-	-	1	10
UT Central	15	-	2	1	3	1	2	3	6	9	3	1	-	4	-	2	-	2	15
Total Irrigation	**63**	**2**	**7**	**5**	**14**	**14**	**9**	**9**	**32**	**46**	**10**	**1**	**-**	**11**	**2**	**5**	**1**	**8**	**65**
					-				-	-				-				-	-
TOTAL New Connects					-				-	-				-				-	-
UT South	920	62	71	62	195	86	88	105	279	474	100	97	150	347	89	88	89	266	1,087
UT North/Metro	4,655	383	241	272	896	356	503	442	1,301	2,197	503	530	339	1,372	577	409	349	1,335	4,904
UT Central	7,650	674	563	922	2,159	599	681	892	2,172	4,331	1,030	1,162	684	2,876	1,051	971	658	2,680	9,887
TOTAL New Connects	**13,225**	**1,119**	**875**	**1,256**	**3,250**	**1,041**	**1,272**	**1,439**	**3,752**	**7,002**	**1,633**	**1,789**	**1,173**	**4,595**	**1,717**	**1,468**	**1,096**	**4,281**	**15,878**

Utah South region includes Moab, Price, Cedar City and Richfield
Utah North/Metro region includes SLC Metro, Odgen 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
Laketown and Smithfield new connects are excluded, as a result of an old coding system that places them under ID/ WY WEST and not Utah.
The Town of Eagle Mountain was integrated into the company network in the American Fork district in Feb/Mar 2015. To achieve this changeover, around 6,500 homes and businesses were added as new connects. These connections are removed from the report as not to affect the accurate representation of new connects and the historical volume trends of newly connected customers.
New connects report reflects the volume of all new connections in the system in the reporting period, which does not include temporary connections, that are subsequently removed in the future periods; it is not necessarily an auditable count of new permeant connection for the reporting period.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH

Tree Program Reporting
January 1, 2015 through December 31, 2015
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2015-12/31/2015 Miles Planned	1/1/2015-12/31/2015 Actual Miles	01/01/2015-12/31/2015 Ahead/Behind	1/1/2015-12/31/2015 % Ahead/Behind	1/1/2014-12/31/2016 Miles Planned	1/1/2014-12/31/2016 Actual Miles	01/01/2014-12/31/2016 Ahead/Behind	1/1/2014-12/31/2016 % Ahead/Behind
	column a	*column b*	*column c*	*column d*	*column e*	*column f*	*column g*	*column h*	*column i*
UTAH	10,964	3,652	3,579	-73	98.0%	7,306	7,572	266	103.6%
AMERICAN FORK	817	272	295	23	108.5%	545	469	-76	86.1%
CEDAR CITY	1,363	454	113	-341	24.9%	903	821	-82	90.9%
JORDAN VALLEY	772	257	218	-39	84.8%	515	551	36	107.0%
LAYTON	304	101	191	90	189.1%	203	218	15	107.4%
MOAB	970	323	665	342	205.9%	647	837	190	129.4%
OGDEN	933	311	340	29	109.3%	622	619	-3	99.5%
PARK CITY	535	178	164	-14	92.1%	357	382	25	107.0%
PRICE	588	196	169	-27	86.2%	392	490	98	125.0%
RICHFIELD	1,342	447	568	121	127.1%	895	815	-80	91.1%
SL METRO	1,192	397	354	-43	89.2%	795	868	73	109.2%
SMITHFIELD	766	255	151	-104	59.2%	511	462	-49	90.4%
TOOELE	482	161	148	-13	91.9%	321	240	-81	74.8%
TREMONTON	651	217	112	-105	51.6%	434	631	197	145.4%
VERNAL	249	83	91	8	109.6%	166	169	3	101.8%

Distribution cycle $/tree:	$106.69
Distribution cycle $/mile:	$3,181
Distribution cycle removal %	19.93%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,471	1,114	1,317	203	6,674	1.031

Transmission $/mile:	$2,847

Current distribution cycle begain January 1, 2014 and extends until December 31, 2016.

Notes:
Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2015 through December 31, 2015
Column c: Actual overhead distribution pole miles worked during the period January, 2015 through December 31, 2015
Column d: Miles ahead or behind for the period January 1, 2015 through December 31, 2015 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2015 through December 31, 2015 ((column c÷b)×100)
Column f: Planned miles cycle to date (April 1, 2005 through April 1, 2008)
Column g: Actual miles cycle to date (April 1, 2005 through April 1, 2008) - Cycle to date
Column h: Miles ahead or behind for the period April 1, 2005 through April 1, 2008 (column j-column i) - cycle to date
Column i: Percent of actual compared to planned for the period April 1, 2005 through April 1, 2008 ((column j÷i)×100) - cycle progress to date

5.2 Budget

UTAH

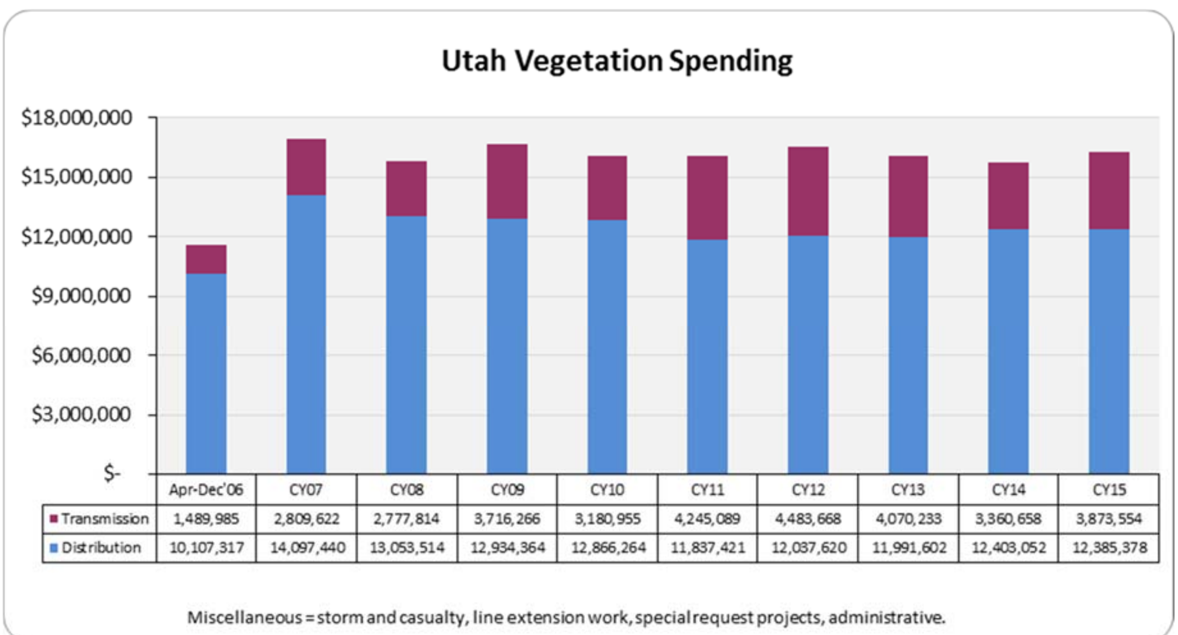
Tree Program Reporting

	CY2016	CY2017	CY2018
Distribution			
Tree Budget	$12,068,854	$12,068,854	$12,068,854
Transmission			
Tree Budget	$3,886,696	$3,886,696	$3,886,696
Total Tree Budget	**$15,955,550**	**$15,955,550**	**$15,955,550**

Calendar year 2015	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$1,010,180	$992,500	$17,680	$286,010	$323,499	-$37,489
Feb	$841,991	$899,236	-$57,245	$323,296	$292,693	$30,603
Mar	$1,025,831	$1,039,132	-$13,301	$357,325	$338,878	$18,447
Apr	$1,020,727	$1,039,132	-$18,405	$352,993	$338,908	$14,085
May	$1,001,463	$945,868	$55,595	$295,792	$308,097	-$12,305
Jun	$1,025,092	$1,039,132	-$14,040	$405,858	$338,908	$66,950
Jul	$926,253	$992,500	-$66,247	$316,163	$323,503	-$7,340
Aug	$1,072,066	$992,500	$79,566	$304,415	$323,503	-$19,088
Sep	$951,368	$992,499	-$41,131	$260,257	$323,503	-$63,245
Oct	$1,149,729	$1,039,131	$110,598	$183,834	$338,908	-$155,074
Nov	$1,092,480	$899,235	$193,245	$422,219	$292,693	$129,526
Dec	$1,268,199	$1,039,135	$229,064	$365,392	$338,908	$26,484
Total	**$12,385,378**	**$11,910,000**	**$475,378**	**$3,873,554**	**$3,882,001**	**-$8,446**

Average # Tree Crews on Property (YTD) **65**

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[12] 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 1366-2003/2012. 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).

[12] 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.

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 and customer requested interruptions.

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.