ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

April 30, 2015

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 2014. 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
Vice President, Regulation
Enclosures

UTAH

SERVICE QUALITY

REVIEW

January 1 – December 31, 2014
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 been working to develop mechanisms that comply with these rules and that will supersede the Company's Service Standards Program.

1.2 Rocky Mountain Power Performance Standards[1]

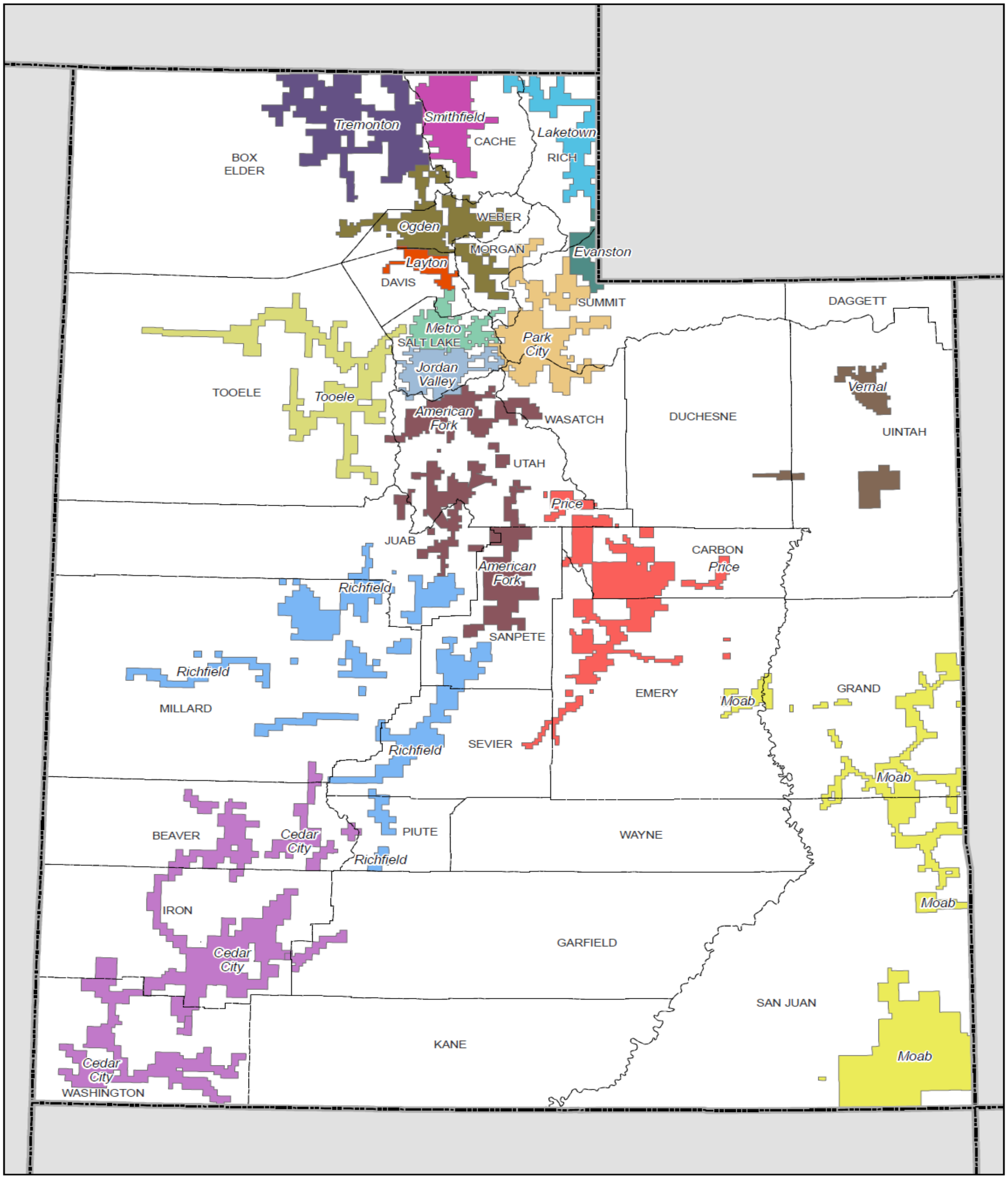
*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	Utah Commission adopted baselines recognizing 365-day rolling (rather than calendar) performance levels of between 152-201 minutes.
*Network Performance Standard 2: Improve System Average Interruption Frequency 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 been working to develop mechanisms that comply with these rules and that will supersede the Company's Service Standards Program.

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 2014 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 2014, there were three major events[2] (which were accepted as major events by the Utah Commission upon recommendation of the Utah Division of Public Utilities) and three significant event days[3] recorded.

Utah Major Events 2014		
Date	**Cause**	**SAIDI**
April 22-23, 2014	Windstorm	21.7
May 10-12, 2014	Wind and Snowstorms	9.3
November 1-2, 2014	Wind and Snowstorms	9.3
	TOTAL	**40.3**

- **<u>April 22-23, 2014</u>**
  A fast-moving windstorm in northern Utah caused substantial damage to Rocky Mountain Power's facilities and a significant impact on its reliability performance April 22 through April 24, 2014. Winds in excess of 80 miles per hour toppled trees into power lines and blew a heavy, contaminated cloud of dust from Utah's west desert into the Wasatch Front. That contamination on facilities, in combination with subsequent light rain, resulted in numerous pole fires. A double-circuit transmission structure carrying two of the three power sources to Summit County, Utah, burned in remote, mountainous terrain and required rolling load curtailment outages during repairs from 7:10 a.m. to noon. This major event filing was accepted by the Utah Commission on 7/1/14 in Docket 14-035-63.
- **<u>May 10-12, 2014</u>**
  Spring storms bringing heavy fog, rain, high winds, lightning and snowfall to southern Utah caused substantial damage to Rocky Mountain Power's facilities and a significant impact on its reliability performance May 10 through May 12, 2014. Wind-blown and snow-laden trees toppled into electrical facilities, blowing fuses, pulling wire down or breaking poles. Sustained interruptions were experienced by 58% of the company's Cedar City customers. This major event filing was accepted by the Utah Commission on 8/4/14 in Docket 14-035-81.
- **<u>November 1-2, 2014</u>**
  Fall storms bringing high winds, rain and snowfall to northeastern and southern Utah caused substantial damage to Rocky Mountain Power's facilities and a significant impact on its reliability performance November 1 through November 3, 2014. Wind-blown and snow-laden trees toppled into electrical facilities, blowing fuses, pulling wire down or breaking poles. Across the state sustained interruptions were experienced by approximately 4% of the company's Utah customers, however within Ogden

[2] Major event threshold shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2014	863,425	6.60	5,699,230
1/1-12/31/2015	869,108	6.52	5,669,347

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

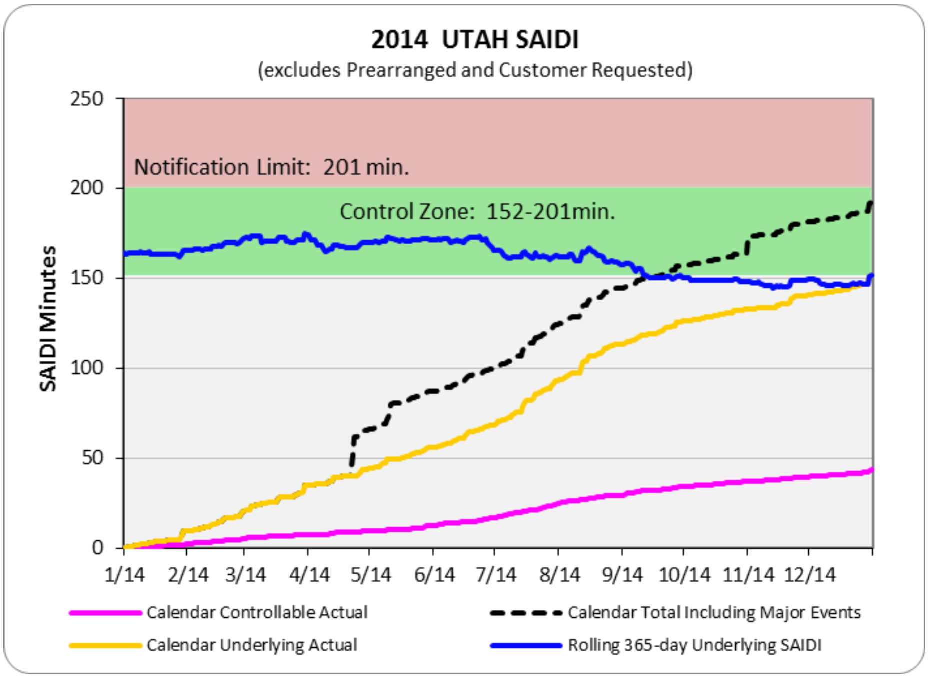
approximately 20% of the company's customers were impacted by the major event. This major event filing was accepted by the Utah Commission on 1/26/15 in Docket 14-035-148.

Utah Significant Event Days 2014			
Date	Cause: General Description	Underlying SAIDI	% of Total Underlying SAIDI (152)
January 29, 2014	Snowstorm: loss of transmission in Montpelier	2.8	1.8%
March 17, 2014	Windstorm: loss of transmission in Price operating area	2.5	1.6%
March 30, 2014	Windstorm: loss of transmission in Moab, Tooele, and Price operating areas	3.5	2.3%
July 14, 2014	Storm: loss of transmission and other weather related outages due to wind across the state	2.7	1.8%
July 15, 2014	Storm: July 14 event continued	2.7	1.8%
July 20, 2014	Wildfire: Fire Marshal requested de-energizing transmission lines in Ogden and other various lightning-related issues across the SLC Metro area	2.9	1.9%
August 12, 2014	Lightning: loss of transmission due to lightning and wind in SLC Metro area	5.1	3.4%
November 22, 2014	Pole fires: outages caused by Winter Storm across SLC Metro area	2.7	1.8%
December 30, 2014	Windstorm: caused outages across SLC Metro area	4.0	2.7%
	TOTAL	**29.1**	**19.1%**

2.1 System Average Interruption Duration Index (SAIDI)

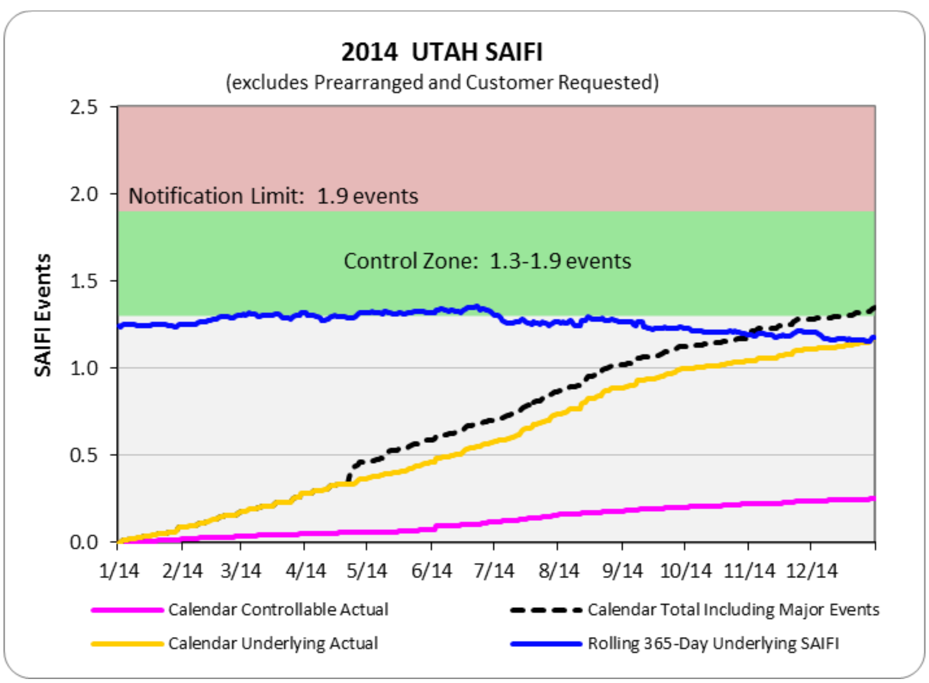
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers.

Utah - SAIDI	January 1 - December 31, 2014
Total	193
Underlying	152
Controllable Distribution	43



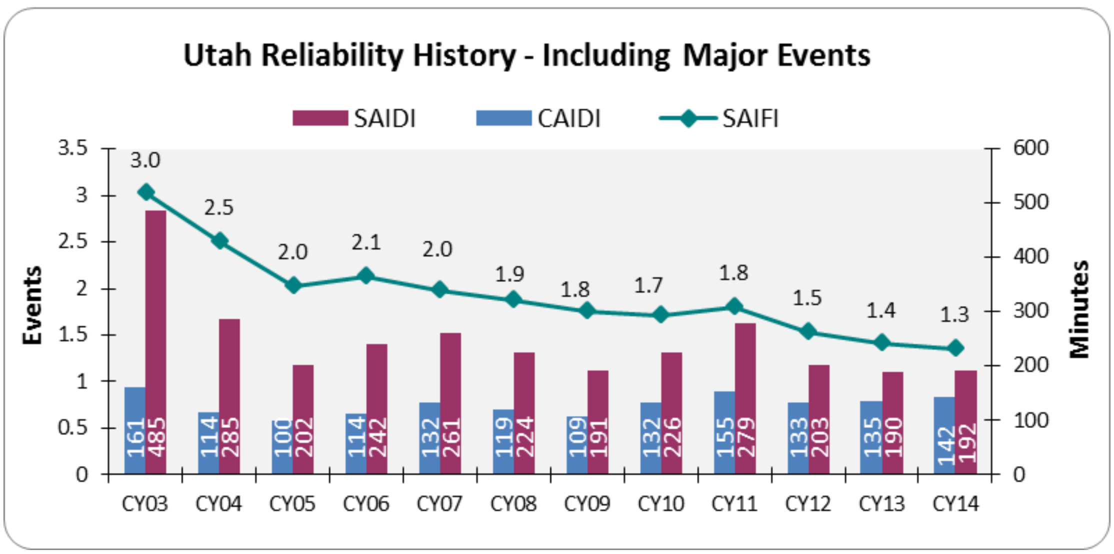
2.2 System Average Interruption Frequency Index (SAIFI)

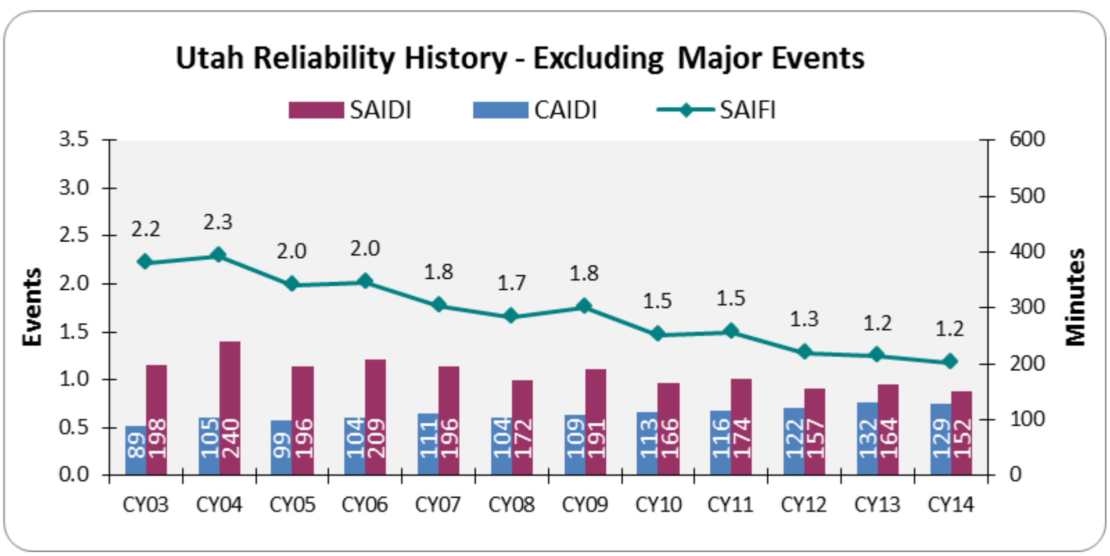
Utah - SAIFI	January 1 - December 31, 2014
Total	1.349
Underlying	1.175
Controllable Distribution	0.255



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.



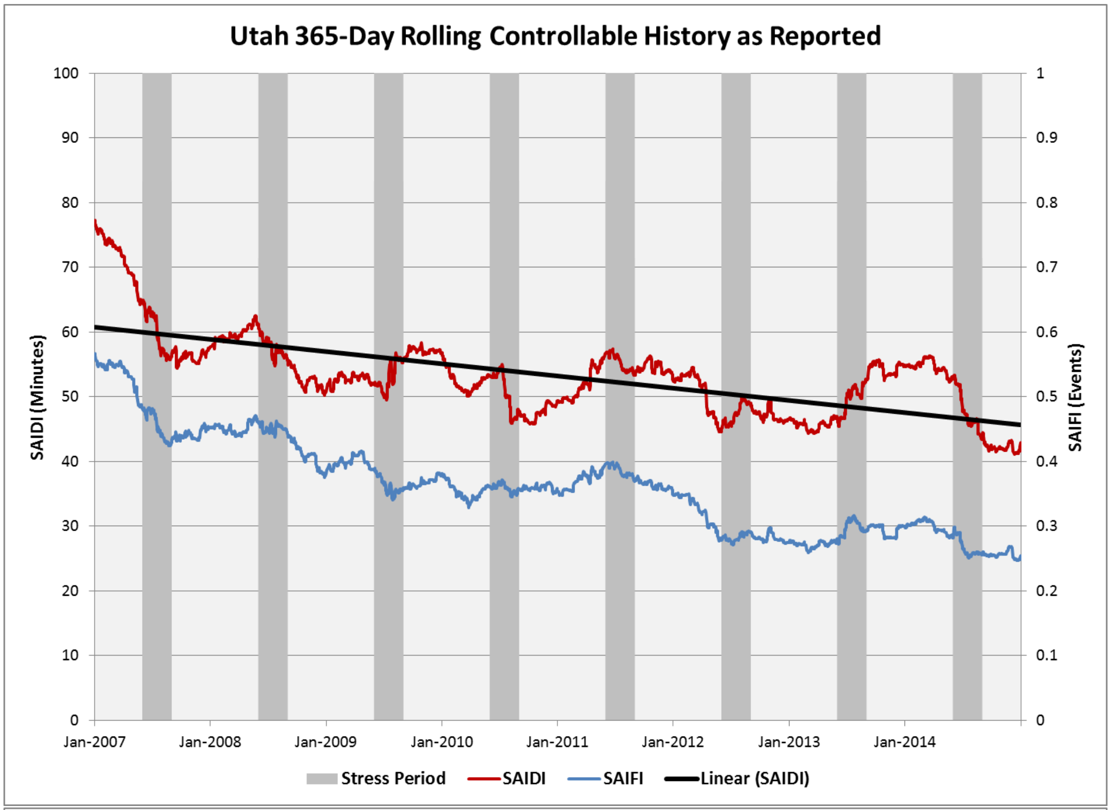


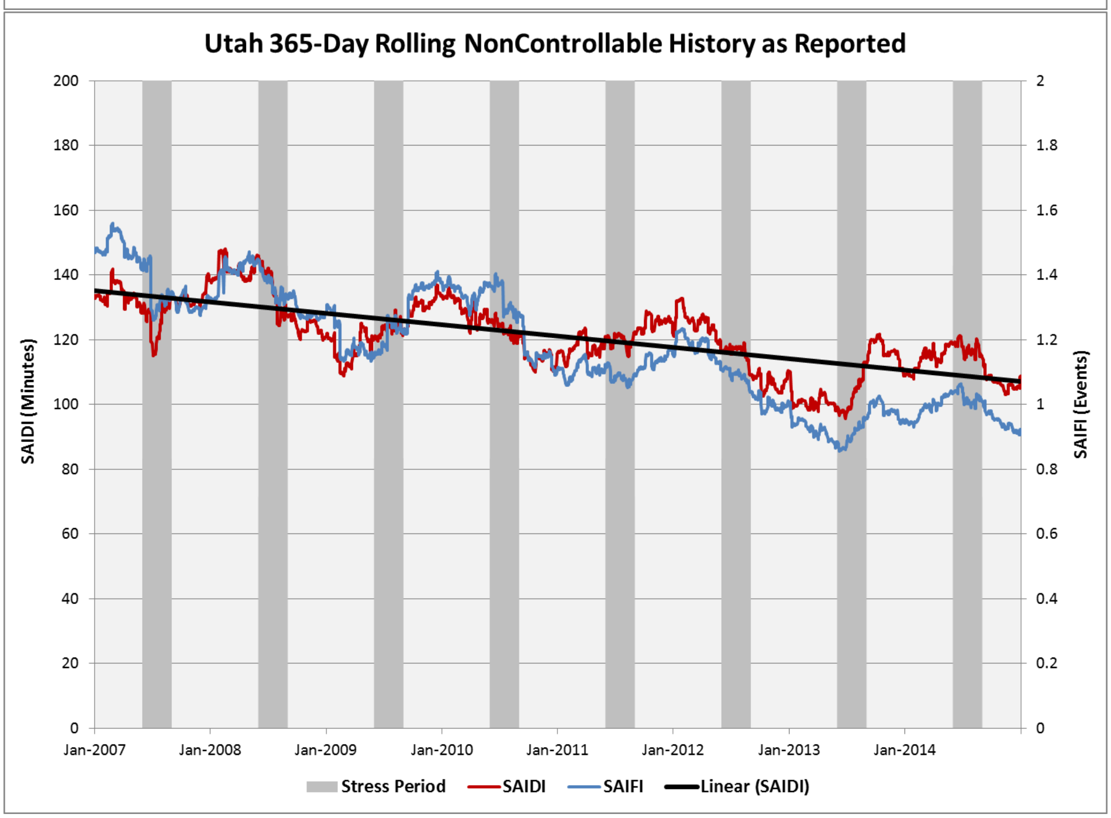
2.4 Controllable, Non-Controllable and Underlying Performance Review

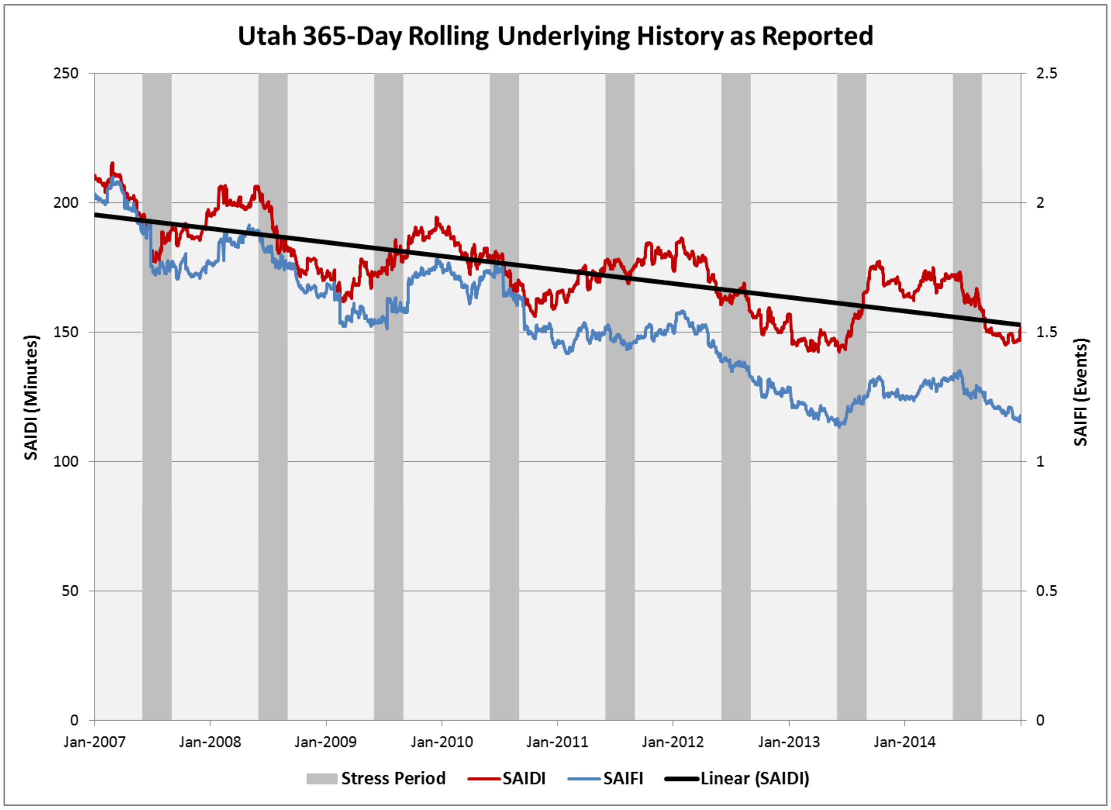
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. This categorization was titled Controllable Distribution outages and recognized that certain types of outages can be cost-effectively 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 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.

[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 Controllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
100
90
80
70
60
50
40
30
20
10
0
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Stress Period
SAIDI
SAIFI
Linear (SAIDI)


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
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.

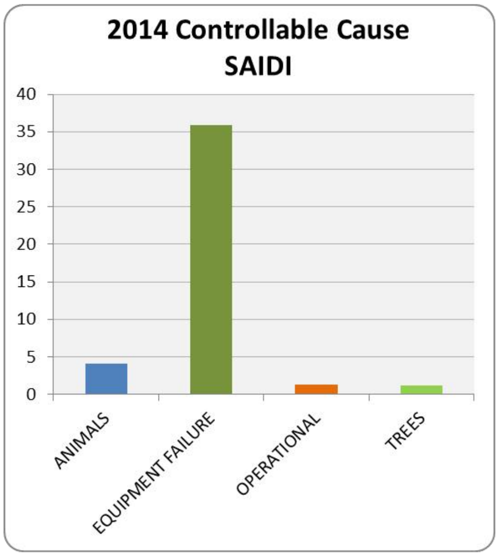
[5] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 863,425 (2014 Utah frozen customer count).

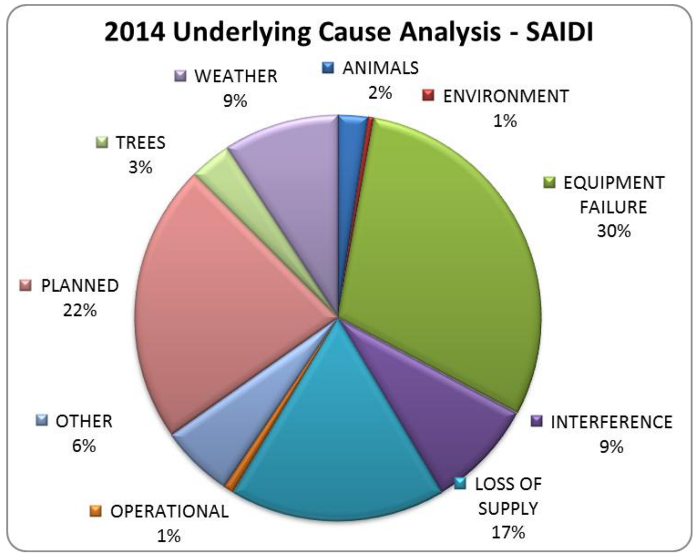
2014 UTAH CAUSE ANALYSIS - CONTROLLABLE

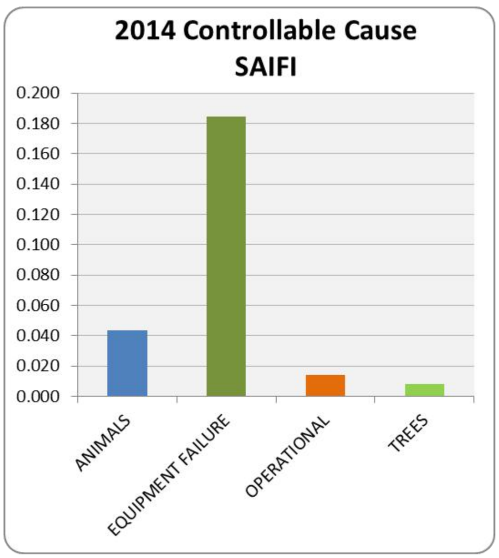
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	1,611,926	22,037	582	1.87	0.026
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,005,665	7,949	320	1.16	0.009
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	548,159	4,292	60	0.63	0.005
BIRD NEST (BMTS)	24,641	243	20	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	299,153	3,176	145	0.35	0.004
ANIMALS	**3,489,545**	**37,697**	**1,127**	**4.04**	**0.044**
B/O EQUIPMENT	3,760,746	25,695	734	4.36	0.030
DETERIORATION OR ROTTING	25,798,274	124,010	4,833	29.88	0.144
OVERLOAD	1,342,125	9,634	128	1.55	0.011
STRUCTURES, INSULATORS, CONDUCTOR	55,980	27	61	0.06	0.000
RELAYS, BREAKERS, SWITCHES	601	9	19	0.00	0.000
EQUIPMENT FAILURE	**30,957,725**	**159,375**	**5,775**	**35.85**	**0.185**
FAULTY INSTALL	26,835	293	44	0.03	0.000
IMPROPER PROTECTIVE COORDINATION	541,078	2,056	20	0.63	0.002
INCORRECT RECORDS	57,383	1,584	55	0.07	0.002
INTERNAL CONTRACTOR	297,513	2,401	7	0.34	0.003
INTERNAL TREE CONTRACTOR	7,072	62	6	0.01	0.000
PACIFICORP EMPLOYEE - FIELD	97,718	4,374	29	0.11	0.005
PACIFICORP EMPLOYEE - SUB	8,658	1,367	1	0.01	0.002
SWITCHING ERROR	35,450	241	2	0.04	0.000
OPERATIONAL	**1,071,708**	**12,378**	**164**	**1.24**	**0.014**
TREE - TRIMMABLE	966,969	6,868	151	1.12	0.008
TREES	**966,969**	**6,868**	**151**	**1.12**	**0.008**
UTAH CONTROLLABLE	**36,485,948**	**216,318**	**7,217**	**42.26**	**0.251**

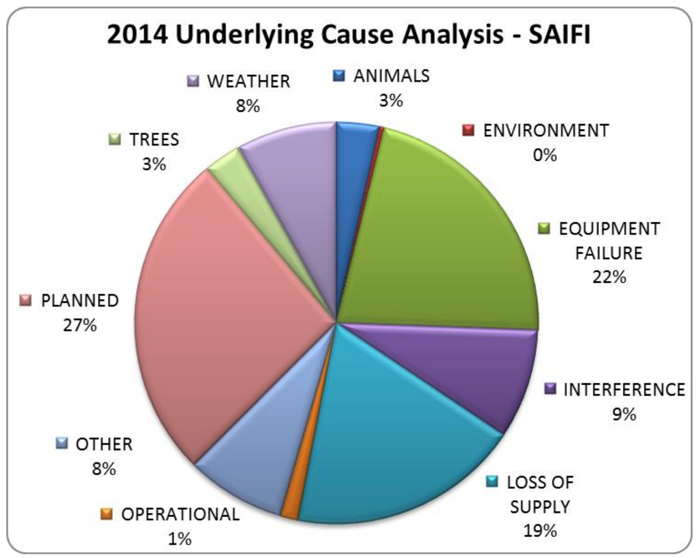
2014 UTAH CAUSE ANALYSIS - UNDERLYING

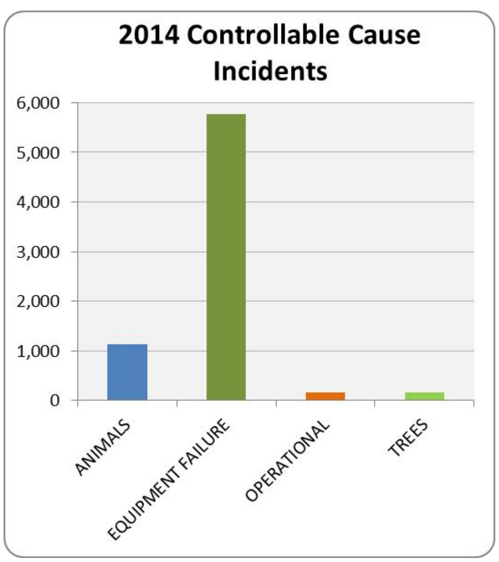
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	1,611,926	22,037	582	1.87	0.026
BIRD MORTALITY (NON-PROTECTED SPECIES)	1,005,665	7,949	320	1.16	0.009
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	548,159	4,292	60	0.63	0.005
BIRD NEST (BMTS)	24,641	243	20	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	299,153	3,176	145	0.35	0.004
ANIMALS	**3,489,545**	**37,697**	**1,127**	**4.04**	**0.044**
CONDENSATION / MOISTURE	240,994	806	1	0.28	0.001
CONTAMINATION	14,456	99	3	0.02	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	333,979	3,339	30	0.39	0.004
FLOODING	76,361	164	4	0.09	0.000
ENVIRONMENT	**665,789**	**4,408**	**38**	**0.77**	**0.005**
B/O EQUIPMENT	3,760,746	25,695	734	4.36	0.030
DETERIORATION OR ROTTING	25,798,274	124,010	4,833	29.88	0.144
NEARBY FAULT	217,005	3,112	15	0.25	0.004
OVERLOAD	1,342,125	9,634	128	1.55	0.011
POLE FIRE	12,453,743	77,069	345	14.42	0.089
STRUCTURES, INSULATORS, CONDUCTOR	55,980	27	61	0.06	0.000
RELAYS, BREAKERS, SWITCHES	601	9	19	0.00	0.000
EQUIPMENT FAILURE	**43,628,473**	**239,556**	**6,135**	**50.53**	**0.277**
DIG-IN (NON-PACIFICORP PERSONNEL)	1,854,396	19,147	326	2.15	0.022
OTHER INTERFERING OBJECT	772,962	7,478	82	0.90	0.009
OTHER UTILITY/CONTRACTOR	532,031	5,413	76	0.62	0.006
VANDALISM OR THEFT	92,021	196	20	0.11	0.000
VEHICLE ACCIDENT	9,363,464	65,152	409	10.84	0.075
INTERFERENCE	**12,614,875**	**97,386**	**913**	**14.61**	**0.113**
FAILURE ON OTHER LINE OR STATION	15	1	4	0.00	0.000
LOSS OF FEED FROM SUPPLIER	29,433	25	4	0.03	0.000
LOSS OF SUBSTATION	4,998,472	38,320	67	5.79	0.044
LOSS OF TRANSMISSION LINE	19,961,981	167,156	393	23.12	0.194
SYSTEM PROTECTION	849	3	12	0.00	0.000
LOSS OF SUPPLY	**24,990,750**	**205,505**	**480**	**28.94**	**0.238**
FAULTY INSTALL	26,835	293	44	0.03	0.000
IMPROPER PROTECTIVE COORDINATION	541,078	2,056	20	0.63	0.002
INCORRECT RECORDS	57,383	1,584	55	0.07	0.002
INTERNAL CONTRACTOR	297,513	2,401	7	0.34	0.003
INTERNAL TREE CONTRACTOR	7,072	62	6	0.01	0.000
PACIFICORP EMPLOYEE - FIELD	97,718	4,374	29	0.11	0.005
PACIFICORP EMPLOYEE - SUB	8,658	1,367	1	0.01	0.002
SWITCHING ERROR	35,450	241	2	0.04	0.000
TESTING/STARTUP ERROR	40	1	1	0.00	0.000
UNSAFE SITUATION	122,187	3,325	2	0.14	0.004
OPERATIONAL	**1,193,935**	**15,704**	**167**	**1.38**	**0.018**
OTHER, KNOWN CAUSE	267,023	3,150	77	0.31	0.004
UNKNOWN	8,224,628	84,970	1,276	9.53	0.098
OTHER	**8,491,651**	**88,120**	**1,353**	**9.83**	**0.102**
CONSTRUCTION	642,913	8,931	452	0.74	0.010
CONSTRUCTION - Scheduled Switching	-	0	169	0.00	0.000
CUSTOMER NOTICE GIVEN	15,296,270	86,623	3,219	17.72	0.100
CUSTOMER REQUESTED	234,231	1,815	874	0.27	0.002
EMERGENCY DAMAGE REPAIR	13,913,769	171,876	1,465	16.11	0.199
ENERGY EMERGENCY INTERRUPTION	1,311	5	1	0.00	0.000
INTENTIONAL TO CLEAR TROUBLE	800,520	11,146	49	0.93	0.013
MAINTENANCE	24,829	7	214	0.03	0.000
TRANSMISSION REQUESTED	1,537,240	10,773	15	1.78	0.012
PLANNED	**32,451,083**	**291,176**	**6,458**	**37.58**	**0.337**
TREE - NON-PREVENTABLE	3,921,427	26,020	434	4.54	0.030
TREE - TRIMMABLE	966,969	6,868	151	1.12	0.008
TREES	**4,888,396**	**32,888**	**585**	**5.66**	**0.038**
FREEZING FOG & FROST	82	1	1	0.00	0.000
ICE	7,304	6	3	0.01	0.000
LIGHTNING	6,085,066	48,331	642	7.05	0.056
SNOW, SLEET AND BLIZZARD	1,207,099	10,250	61	1.40	0.012
WIND	6,043,999	30,656	402	7.00	0.036
Weahter	**13,343,549**	**89,244**	**1,109**	**15.45**	**0.103**
Utah Including Prearranged	**145,758,046**	**1,101,684**	**18,365**	**168.81**	**1.276**
Utah Excluding Prearranged	**130,227,545**	**1,013,246**	**14,103**	**150.83**	**1.174**

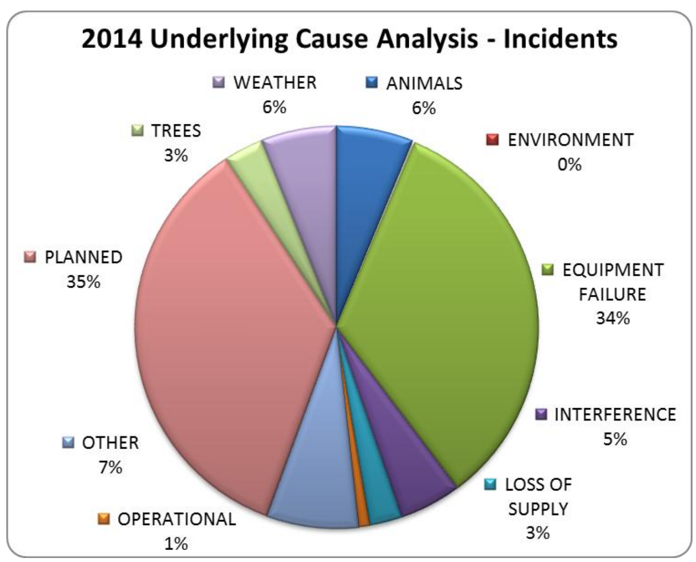

2014 Controllable Cause SAIDI
40
35
30
25
20
15
10
5
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

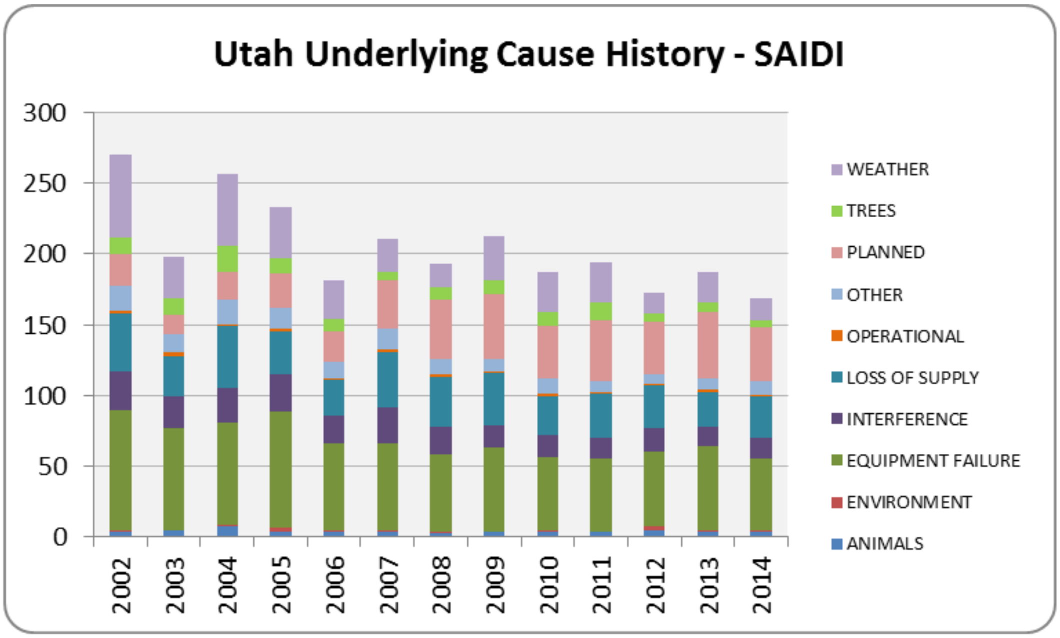

2014 Underlying Cause Analysis - SAIDI
WEATHER 9%
ANIMALS 2%
ENVIRONMENT 1%
TREES 3%
EQUIPMENT FAILURE 30%
PLANNED 22%
OTHER 6%
INTERFERENCE 9%
LOSS OF SUPPLY 17%
OPERATIONAL 1%

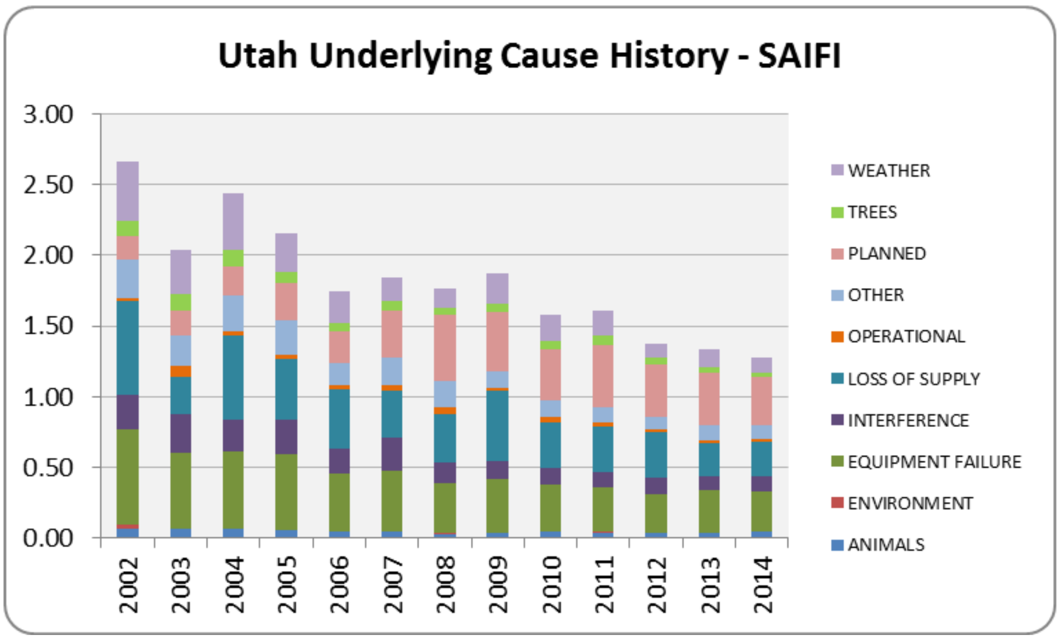

2014 Controllable Cause SAIFI
0.200
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


2014 Underlying Cause Analysis - SAIFI
WEATHER 8%
ANIMALS 3%
TREES 3%
ENVIRONMENT 0%
EQUIPMENT FAILURE 22%
PLANNED 27%
INTERFERENCE 9%
OTHER 8%
LOSS OF SUPPLY 19%
OPERATIONAL 1%


2014 Controllable Cause Incidents
6,000
5,000
4,000
3,000
2,000
1,000
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


2014 Underlying Cause Analysis - Incidents
WEATHER 6%
ANIMALS 6%
TREES 3%
ENVIRONMENT 0%
PLANNED 35%
EQUIPMENT FAILURE 34%
INTERFERENCE 5%
OTHER 7%
LOSS OF SUPPLY 3%
OPERATIONAL 1%


Utah Underlying Cause History - SAIDI
300
250
200
150
100
50
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS


Utah Underlying Cause History - SAIFI
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

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.

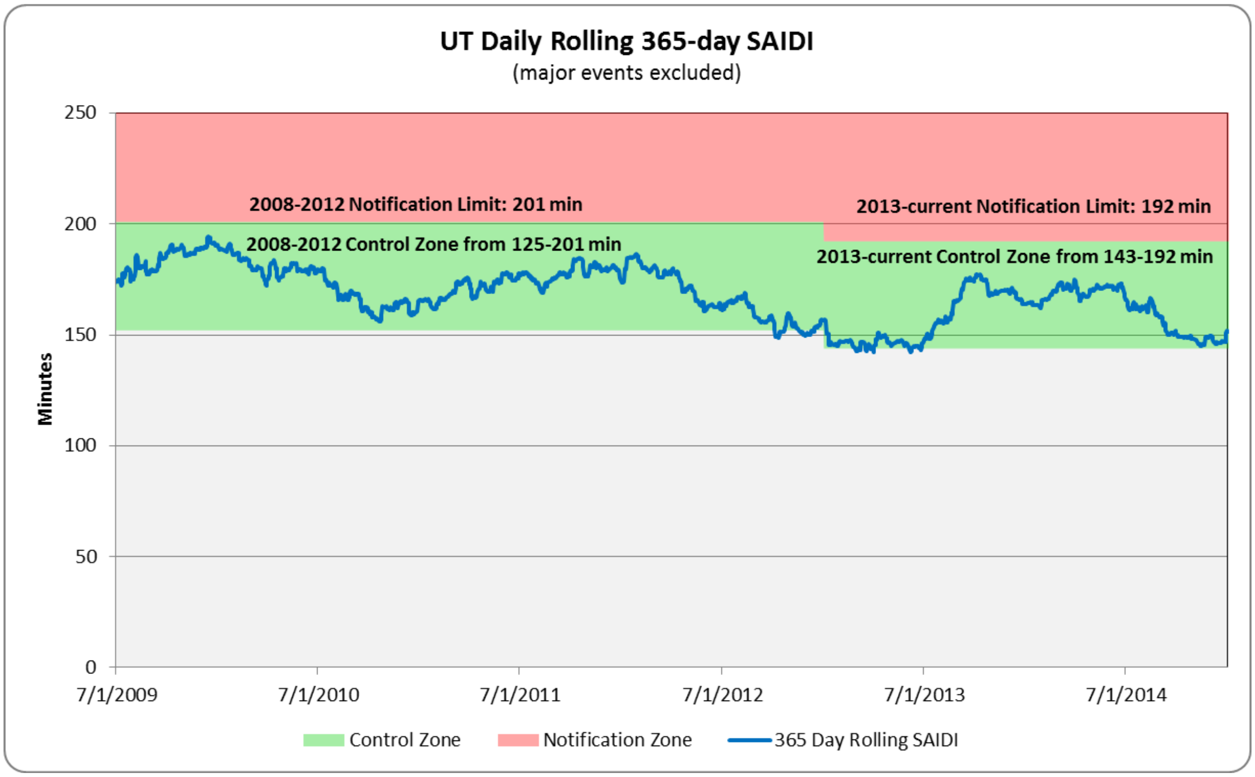
2.6 Baseline Performance

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, 2014 yields the values shown below.

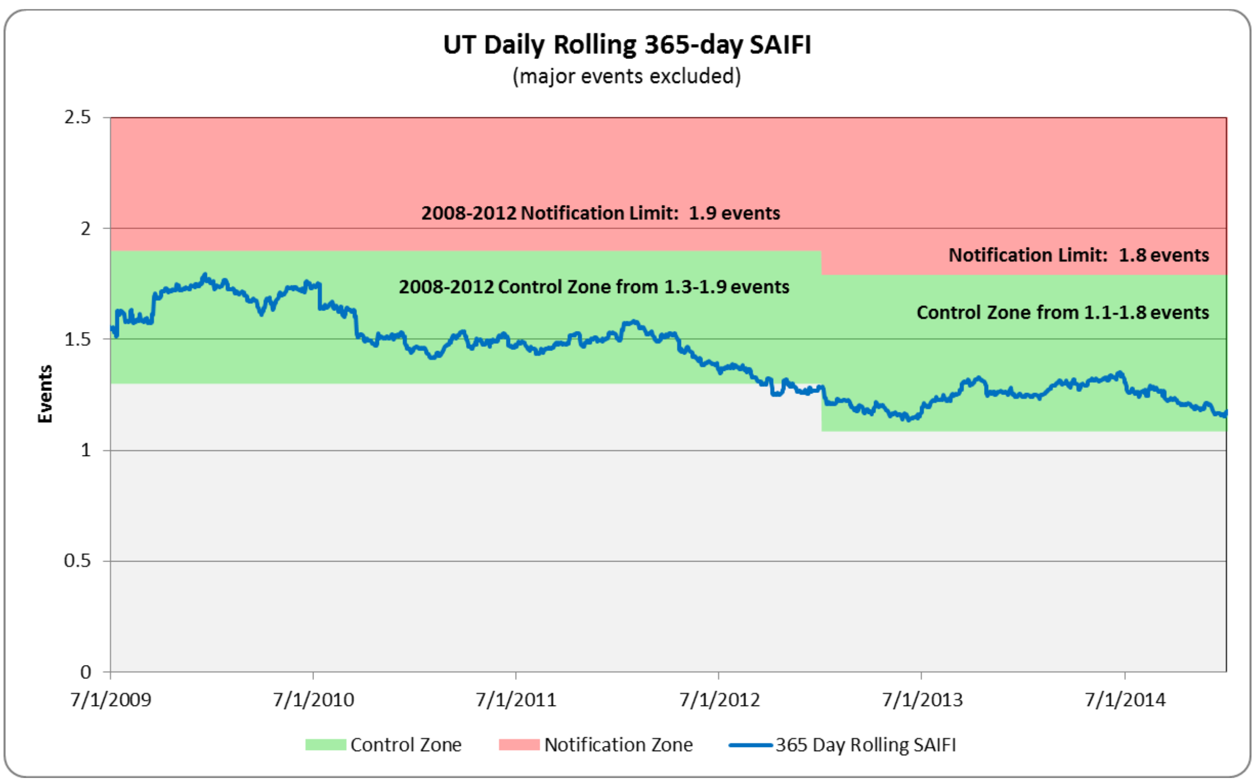
The Company refreshed the dataset and calculated using the last six years of daily reliability data, which was selected to align with major event calculations, but required the addition of the prior 365 days in order to construct the daily rolling 365-days curves used for these calculations. The 365-day 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, 2014 result in an average of 168 minutes and 1.44 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.

Baseline	As Filed (history through December 31, 2012)			Current Period (2014-December)		
	365-Day Average	Lower Value Control Zone	Upper Value Control Zone (Notification Limit)	365-Day Average	Lower Value Control Zone	Upper Value Control Zone (Notification Limit)
SAIDI	176 minutes	152 minutes	201 minutes	168 minutes	144 minutes	192 minutes
SAIFI	1.59 events	1.3 events	1.9 events	1.44 events	1.1 events	1.8 events

Baseline Summary SAIDI



Baseline Summary SAIFI



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

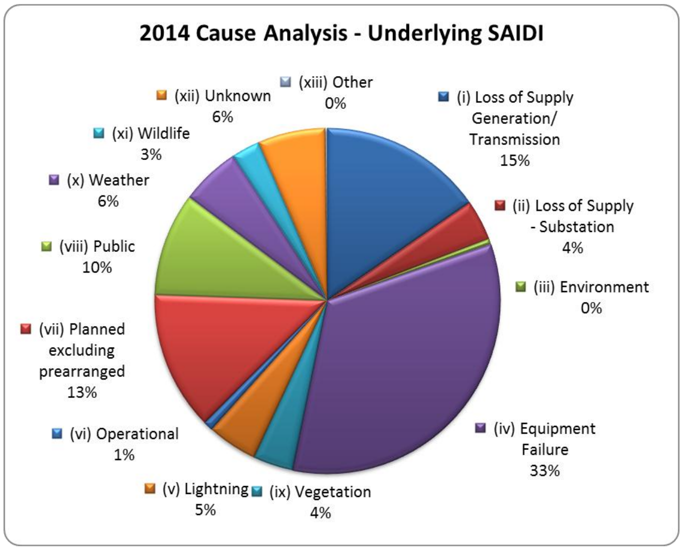
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Rule R 746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least 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.

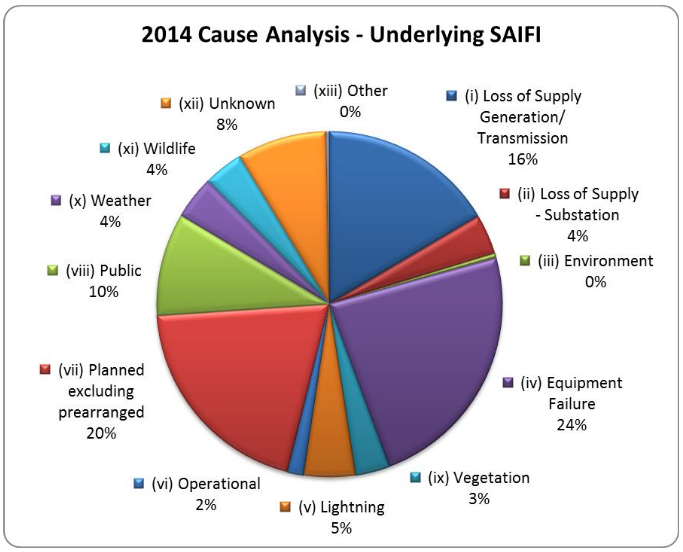
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$ are required.

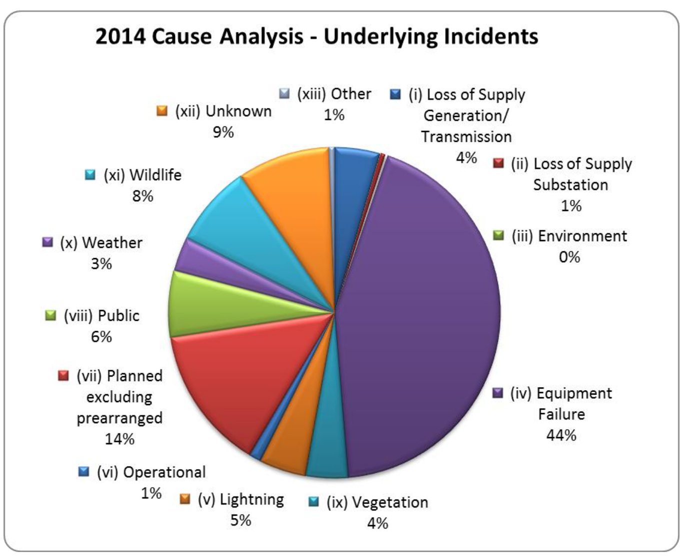
Major Events and Prearranged Excluded*	2010				2011				2012				2013				2014			
STATE	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFIe**
Utah	166	1.5	113	1.33	174	1.5	116	1.10	157	1.3	122	0.72	164	1.2	132	0.81	152	1.2	129	1.21
OP AREA																				
AMERICAN FORK	148	1.2	124		132	1.3	106		101	0.8	135		126	1.3	99		113	1.0	109	
CEDAR CITY	296	2.5	118		218	1.7	131		279	1.8	154		225	1.8	127		170	1.1	151	
CEDAR CITY (MILFORD)	389	2.1	183		980	8.1	121		363	2.8	129		707	3.3	213		891	3.3	271	
JORDAN VALLEY	112	1.0	116		113	0.9	121		106	0.8	129		106	0.7	145		103	0.7	141	
LAYTON	151	1.1	142		155	1.3	124		105	0.8	131		105	1.0	109		108	0.8	127	
MOAB	286	2.6	111		151	1.8	86		375	3.1	122		284	1.9	147		412	2.3	181	
OGDEN	171	1.8	96		204	1.8	116		153	1.3	117		168	1.4	122		218	1.9	113	
PARK CITY	251	2.2	116		186	1.6	116		184	1.8	100		232	1.5	155		147	1.1	140	
PRICE	505	3.4	150		421	2.5	166		133	1.4	97		514	1.8	293		394	2.2	180	
RICHFIELD	255	2.9	87		369	3.2	114		200	2.0	100		469	3.4	138		181	1.7	104	
RICHFIELD (DELTA)	189	2.5	76		316	3.6	89		329	2.9	113		316	3.7	85		202	1.9	108	
SLC METRO	144	1.3	107		178	1.5	117		129	1.2	112		170	1.2	139		145	1.1	129	
SMITHFIELD	229	1.7	135		174	1.6	106		267	2.6	102		81	0.7	117		114	0.9	126	
TOOELE	178	1.3	134		329	3.0	110		595	3.7	163		137	1.3	103		239	2.1	115	
TREMONTON	346	3.4	102		255	2.2	115		447	3.0	147		335	3.3	102		216	2.0	111	
VERNAL	105	0.9	115		117	2.2	54		236	2.9	82		160	2.1	75		119	1.2	101	

* except MAIFIe

Utah Cause Category	2010		2011		2012		2013		2014	
	SAIDI	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Environment	1	0.0	0	0.0	4	0.0	0	0.0	1	0.0
Equipment Failure	53	0.3	52	0.3	53	0.3	60	0.3	51	0.3
Lightning	7	0.1	9	0.1	4	0.0	9	0.1	7	0.1
Loss of Supply - Generation/Transmission	21	0.3	26	0.3	25	0.3	19	0.2	23	0.2
Loss of Supply - Substation	7	0.1	6	0.1	5	0.1	6	0.0	6	0.0
Operational	1	0.0	1	0.0	0	0.0	1	0.0	1	0.0
Other	0	0.0	1	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	17	0.3	23	0.3	22	0.3	24	0.3	20	0.2
Public	15	0.1	15	0.1	16	0.1	14	0.1	15	0.1
Unknown	10	0.1	7	0.1	7	0.1	8	0.1	10	0.1
Vegetation	10	0.1	13	0.1	5	0.1	7	0.0	6	0.0
Weather	21	0.1	19	0.1	11	0.1	12	0.1	8	0.0
Wildlife	4	0.0	4	0.0	4	0.0	4	0.0	4	0.0
UTAH Underlying	**166**	**1.5**	**174**	**1.5**	**157**	**1.3**	**164**	**1.2**	**151**	**1.2**


2014 Cause Analysis - Underlying SAIDI
(xiii) Other 0%
(i) Loss of Supply Generation/ Transmission 15%
(ii) Loss of Supply - Substation 4%
(iii) Environment 0%
(iv) Equipment Failure 33%
(ix) Vegetation 4%
(v) Lightning 5%
(vi) Operational 1%
(vii) Planned excluding prearranged 13%
(viii) Public 10%
(x) Weather 6%
(xi) Wildlife 3%
(xii) Unknown 6%


2014 Cause Analysis - Underlying SAIFI
(xiii) Other 0%
(i) Loss of Supply Generation/ Transmission 16%
(ii) Loss of Supply - Substation 4%
(iii) Environment 0%
(iv) Equipment Failure 24%
(ix) Vegetation 3%
(v) Lightning 5%
(vi) Operational 2%
(vii) Planned excluding prearranged 20%
(viii) Public 10%
(x) Weather 4%
(xi) Wildlife 4%
(xii) Unknown 8%


2014 Cause Analysis - Underlying Incidents
(xiii) Other 1%
(i) Loss of Supply Generation/ Transmission 4%
(ii) Loss of Supply Substation 1%
(iii) Environment 0%
(iv) Equipment Failure 44%
(ix) Vegetation 4%
(v) Lightning 5%
(vi) Operational 1%
(vii) Planned excluding prearranged 14%
(viii) Public 6%
(x) Weather 3%
(xi) Wildlife 8%
(xii) Unknown 9%

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), 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 Selections for CY2015 (Program Year 16)

In prior Service Quality Reports the Company has advocated certain circuits be designated as Worst Performers. Prior comments received identified that the Company should list explicitly the 10 circuits experiencing the highest (or poorest) CPI score, with an explanation designating their treatment as a Worst Performer. Finally, the rationale for the five circuits selected is also required. The table below is responsive to this modification to the report.

Circuit Name	2014 CPI99	2013 CPI99	2012 CPI99	Stakeholder Comments
LITTLE MOUNTAIN #18	1,785	2,510	2,416	Circuit no longer exists
JORDAN #16	1,025	19	40	Customer count shifts from year to year impacts circuit SAIDI and SAIFI. CML and Sustained incidents evaluated by FE show good performance
RESEARCH #13	872	193	243	Recent performance shows significant improvement
STANSBURY #11	783	58	43	One large unavoidable outage (animal guarded substation)
RED MOUNTAIN #33 APEX MINE	768	922	1,626	Circuit has an improving trend, expect continued improvement
CLEAR LAKE #11	742	693	1,073	Not WPC; on watch-list for RWP. Lightning issues? High cost per avoided CML
FOUNTAIN GREEN #12	687	785	744	Improving trend, three year score is impacted by a range fire in 2012. Monitor UG failure trend
RED MOUNTAIN #32 SHIVWITS	572	410	366	Likelihood of two year project delivery is low due to land right issues
BIG MOUNTAIN #11	545	650	996	Improving trend, three year score is impacted by a weather event in 2012. Review substation improvements with sub ops.
PONDEROSA #11	493	329	288	Localized issue at FP241002 and FP253401 will be addressed through reliability work plan process
TOQUERVILLE #31	475	361	398	The sustained incidents and the CML for 2014 were over double the three year average 2011-2013. CPI99 score increasing against the average.
RATTLESNAKE #22	456	329	371	Over last four years this circuit averages 21 sustained incidents and has had over 1 million CML the last three years. The CPI99 score is increasing against the average.

BRIGHTON #12	270	174	579	The sustained incidents and the CML for 2014 were over double the three year average 2011-2013.
NIBLEY #21	179	192	205	This circuit averages 45 sustained incidents per year over 2011-2014
DECKER LAKE #12	167	120	88	This was a 2010 WPC and it has not maintained improvement from its initial selection score. It is increasing in CPI99 score against the average and increasing in CML against the average.

2.8.2 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. Goal Met is reported and then that program year removed from future Service Quality Reports.

WORST PERFORMING CIRCUITS	STATUS	BASELINE[6]	Performance 12/31/2014
Program Year 15: (CY2014)			
Skull Valley 11	IN PROGRESS	468	440
Fort Douglas 13	IN PROGRESS	417	140
Parowan Valley 25	IN PROGRESS	408	355
Brighton 21	IN PROGRESS	364	188
Bush 12	IN PROGRESS	281	281
TARGET SCORE = **248**		**310**	**281**
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	81
Eden 11	COMPLETE	116	234
Bush 11	COMPLETE	228	309
Pioneer 12	COMPLETE	177	145
Grantsville 12	COMPLETE	250	218
TARGET SCORE = 108		**135**	**197**
Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	198
East Bench 12	COMPLETE	112	66
Clinton 11	COMPLETE	133	35
Redwood 16	COMPLETE	145	55
Orangeville 11	COMPLETE	114	19

[6] 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 on each of the circuits. The application of CPI99 proved to demonstrate more consistently how performance comparisons could be made.

TARGET SCORE = **114**	**Target Met**	**142**	**75**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	46
Huntington City 12	COMPLETE	285	109
Magna 15	COMPLETE	140	92
Gunnison 12	COMPLETE	110	104
Capitol 11	COMPLETE	129	50
TARGET SCORE = **134**	**Target Met**	**167**	**80**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	167
North Bench 13	COMPLETE	95	54
Newgate 14	COMPLETE	164	59
Newton 12	COMPLETE	105	83
St Johns 11	COMPLETE	547	361
TARGET SCORE = **162**	**Target Met**	**203**	**145**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	54
Mathis 12	COMPLETE	132	79
Parrish 11	COMPLETE	137	43
Valley Center 11	COMPLETE	169	50
Hammer 15	COMPLETE	95	50
TARGET SCORE = **104**	**Target Met**	**129**	**55**

Note: Goals were met for Program Years 1 through 12 and filed in prior reporting periods; however, data for Program Years 10-12 are retained in this report in order to show circuit selections of the past 6 program years for discussion purposes.

2.9 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
CUMULATIVE January – December 2014 = 81%					
January	February	March	April	May	June
85%	81%	87%	79%	75%	87%
July	August	September	October	November	December
76%	84%	79%	73%	85%	72%

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.

2014 CAIDI (Average Outage Duration)	
Underlying Performance	133 minutes
Total Performance	145 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[7] complaints within 30 days	100%	100%

[7] 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.

During 2014, there were two dates identified as a wide-scale outage day; call statistics are shown in the table below. The outage event on January 3rd was a substation bus lockout at Mcclelland substation in Utah, which affected the 46 kV system, resulting in approximately 8,320 customers out of service for approximately 20 minutes. The outage events that resulted in the wide-scale outage on August 12 were due to a loss of transmission cause by summer storm activity (including lightning).

Date	Interval start/finish (Mountain Time)		Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
1/3/2014	13:30	13:44	548	0	13	193	83
	13:45	13:59	546	21	25	247	113
	14:00	14:14	608	39	29	246	169
	14:15	14:29	1586	401	55	591	92
	14:30	14:44	1439	716	5	642	147
	14:45	14:59	537	0	8	614	27
	15:00	15:14	571	8	14	194	67
8/12/2014	15:30	15:44	354	1	47	488	43
	15:45	15:59	650	46	150	346	54
	16:00	16:14	2024	160	2	90	15
	16:15	16:29	402	0	9	123	44
	16:30	16:44	398	0	3	135	32

Twenty First Century, an external Interative Voice Response (IVR) 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 2014

Utah

	Description	2014 Events	2014 Failures	2014 % Success	2014 Paid	2013 Events	2013 Failures	2013 % Success	2013 Paid
CG1	Restoring Supply	1,017,071	0	100%	$0	1,058,805	1	100%	$50
CG2	Appointments	7,115	26	99.6%	$1,300	6,567	9	99.9%	$450
CG3	Switching on Power	8,134	2	99.9%	$100	10,958	5	99.95%	$250
CG4	Estimates	1,263	5	100%	$250	1,340	4	99.7%	$200
CG5	Respond to Billing Inquiries	1,808	3	100%	$150	1,612	1	99.9%	$50
CG6	Respond to Meter Problems	978	0	100%	$0	926	1	100%	$50
CG7	Notification of Planned Interruptions	86,658	79	99.91%	$3,950	70,152	58	99.9%	$2,900
		1,123,027	**115**	**99.9%**	**$5,750**	**1,150,360**	**79**	**99.9%**	**$3,950**

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[8], 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.[9]
- Pole testing includes a sound and bore to identify decay pockets that would compromise the wood pole's structural integrity.

Substations and Major Equipment

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

Corrective Maintenance

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

Transmission and Distribution Lines

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

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[8] 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.

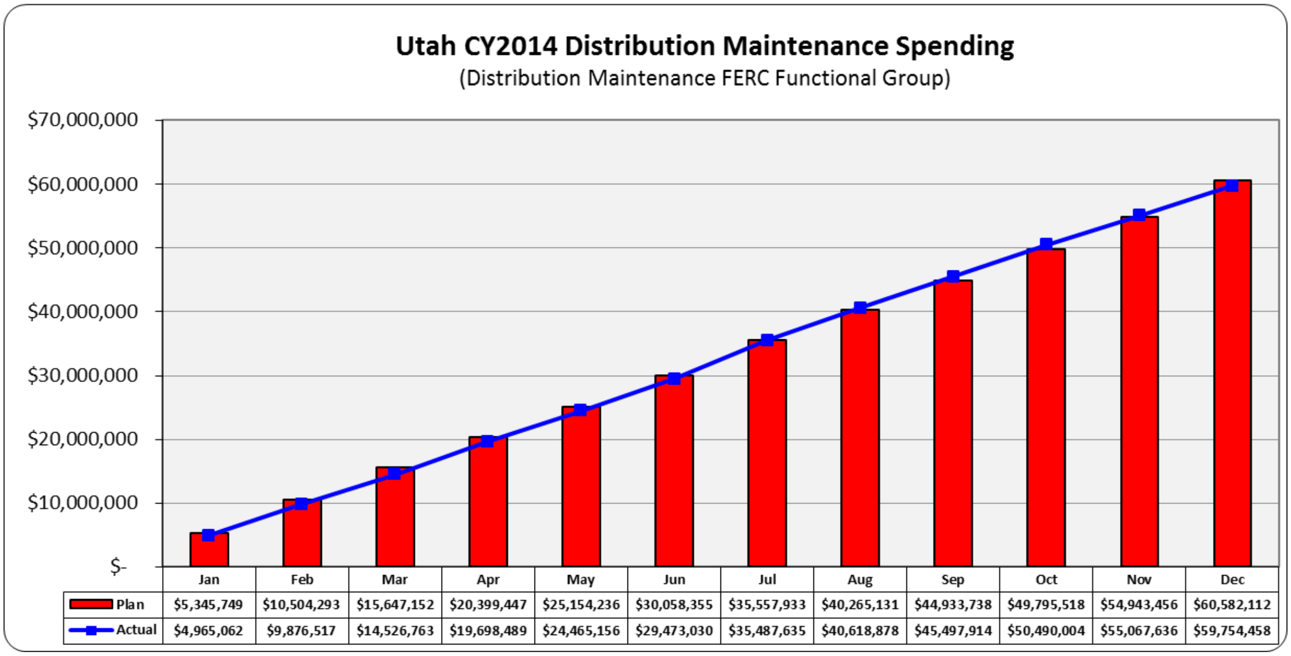
Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. Priority G: Conditions that conform to the regulations requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered"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

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

Substations and Major Equipment

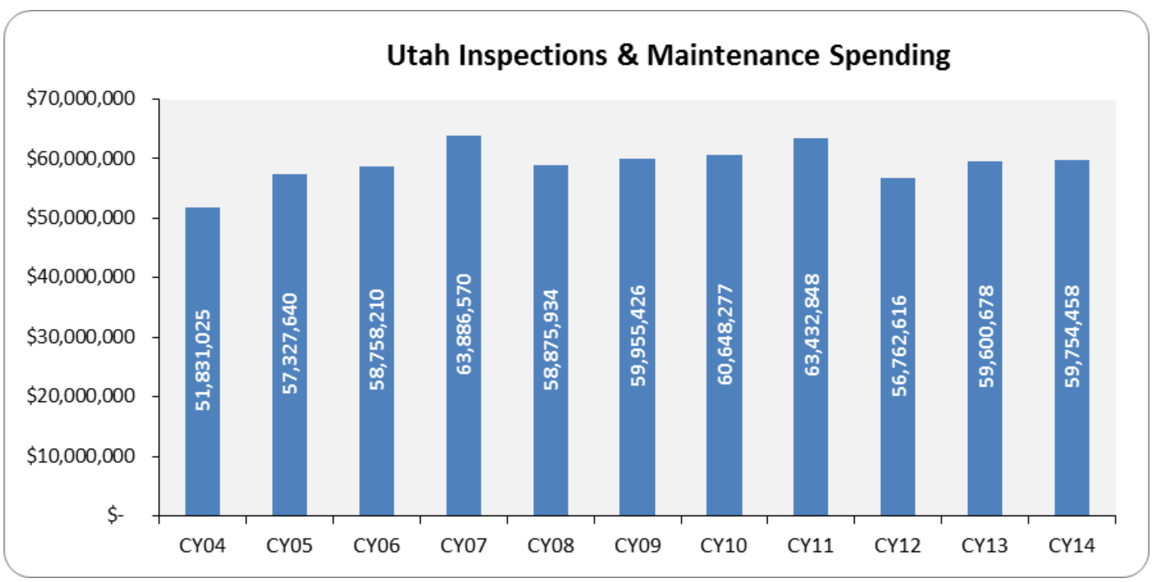
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending [10]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,345,749	$10,504,293	$15,647,152	$20,399,447	$25,154,236	$30,058,355	$35,557,933	$40,265,131	$44,933,738	$49,795,518	$54,943,456	$60,582,112
Actual	$4,965,062	$9,876,517	$14,526,763	$19,698,489	$24,465,156	$29,473,030	$35,487,635	$40,618,878	$45,497,914	$50,490,004	$55,067,636	$59,754,458

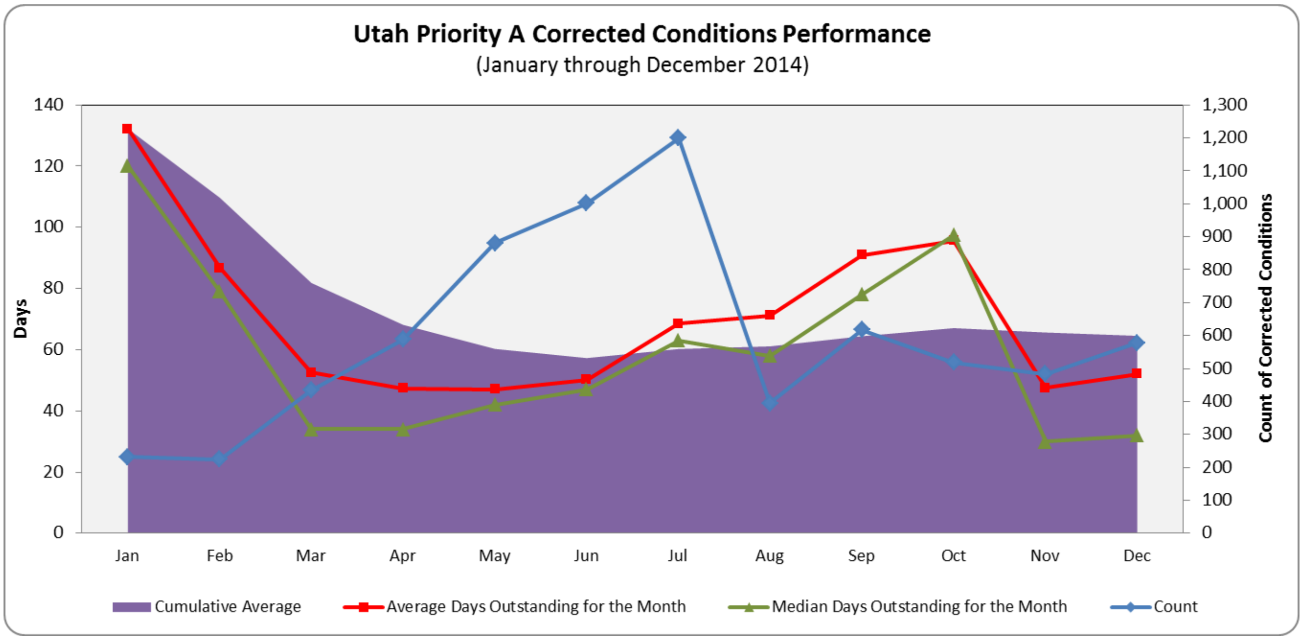
3.2.1 Maintenance Historical Spending



10 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. An individual month may exceed the target as happened in January, however, the cumulative average remains well below the target.



Oldest Outstanding Priority A Conditions In Utah

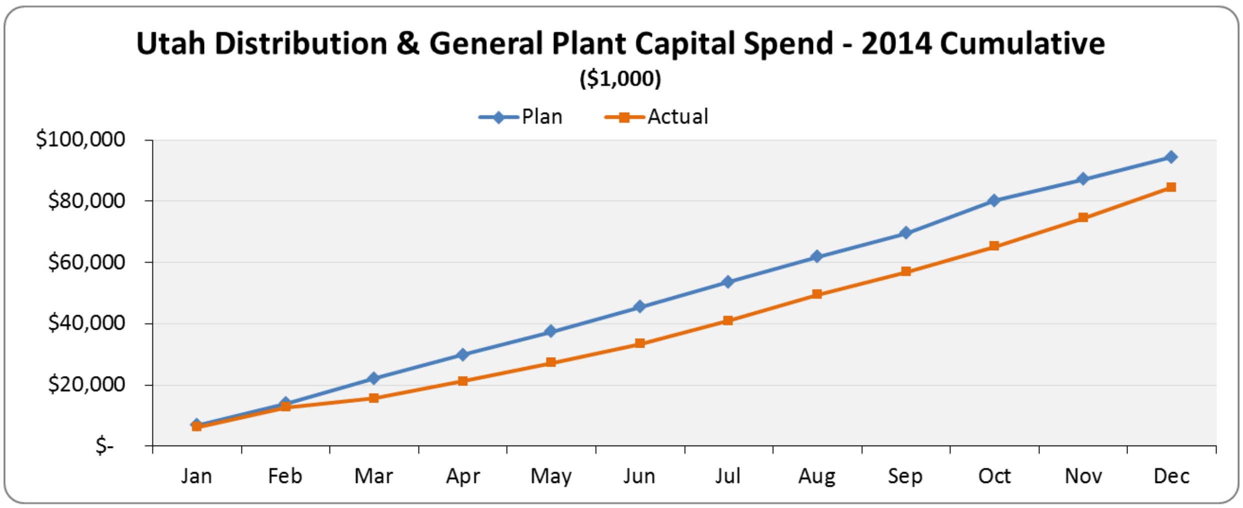
District	Mapstring	Pole	Condition	Inspection Remarks	Inspection Date	Completion Date	Days to Correct	Circuit	Explanation
Ogden	11103002	131000	BOPOLE	DECAY REJECT RESTORE_SR 1.59_SHELL ROT	4/16/2014	1/21/2015	280	MGN11	The local district managers initially planned to use internal resources to complete the work, but the workload increased to a point that a contract resource was required to complete.
Ogden	11205002	20212	BORECL	LID HINGE IS RUSTED AND FALLING APART	3/27/2014	1/23/2015	302	MID14	The local management determined the condition was not a safety hazard and elected to correct the condition in conjunction with a scheduled UDOT road widening project.
Ogden	11205001	224702	POLESTUB	POWER SUPPLY TO VACATE WHEN PULLED COMCAST TO NOTIFY	3/5/2014	1/21/2015	322	UIN12	RMP needed to wait for Comcast to remove their equipment before RMP could remove the pole. The polestub was removed on 5/30/14, however the FPI condition was not cleared until the local manager fielded the pole and verified it was removed on 1/21/15.
Metro	11301001	351244	BOXFRMR	ACTIVELY LEAKING OIL;OR BROKEN LATCH/HINGES	4/14/2014	1/28/2015	289	MEA15	As the conditions were being readied for correction it was determined that work should be expanded to address adjacent lower priority conditions and replace more equipment. Designs and subsequent outage coordination pushed the project's completion date.
Metro	11301001	351402	BOXFRMR	ACTIVELY LEAKING OIL;OR BROKEN LATCH/HINGES	4/14/2014	1/28/2015	289	MEA15	

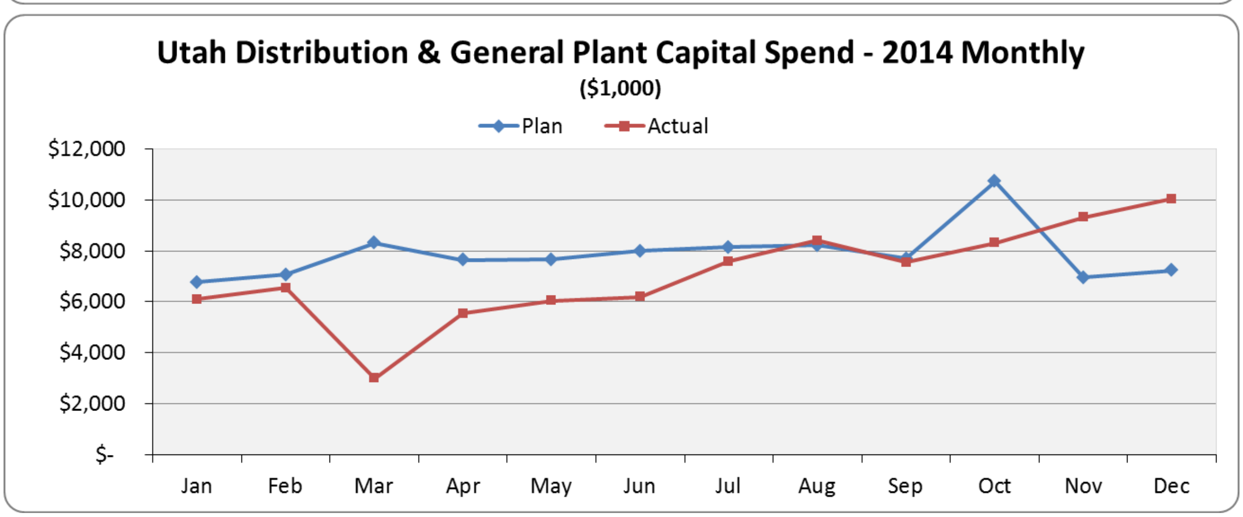
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January –December 2014

Investment	Actuals ($M)	Plan ($M)	Significant Variances
1. Mandated	$6.7	$9.4	Mandated environmental/avian protection over plan, (+$1.1M); mandated road relocations and national/regional regulatory (WECC, FERC, etc.) under plan, (-$3.8M). *(Note: Plan included $2.9M for UDOT MVC Wasatch Restoration Center Relocation, Oct-2014).*
2. New Connect	$34.6	$43.1	Residential, commercial and street light new connects under plan, (-$8.2M). *(Note: Actuals include $2.7M transfer from distribution to transmission for prior year City Creek project costs, Mar-2014).*
3. System Reinforcement	$6.3	$8.5	Subtransmission reinforcement over plan, (+$0.5M); feeder and substation reinforcement under plan, (-$2.6M).
4. Replacement	$32.5	$29.9	Replacements for underground cable, vaults/equipment and vehicles (transport) over plan, (+$4.8M); replacements for substation transformers and overhead distribution lines/other under plan, (-$2.3M).
5. Upgrade & Modernize	$4.4	$3.5	Feeder improvement and functional reliability upgrades over plan (+$1.7M); economically justified upgrades under plan (-$1.1M).
Total	**$84.6**	**$94.4**	

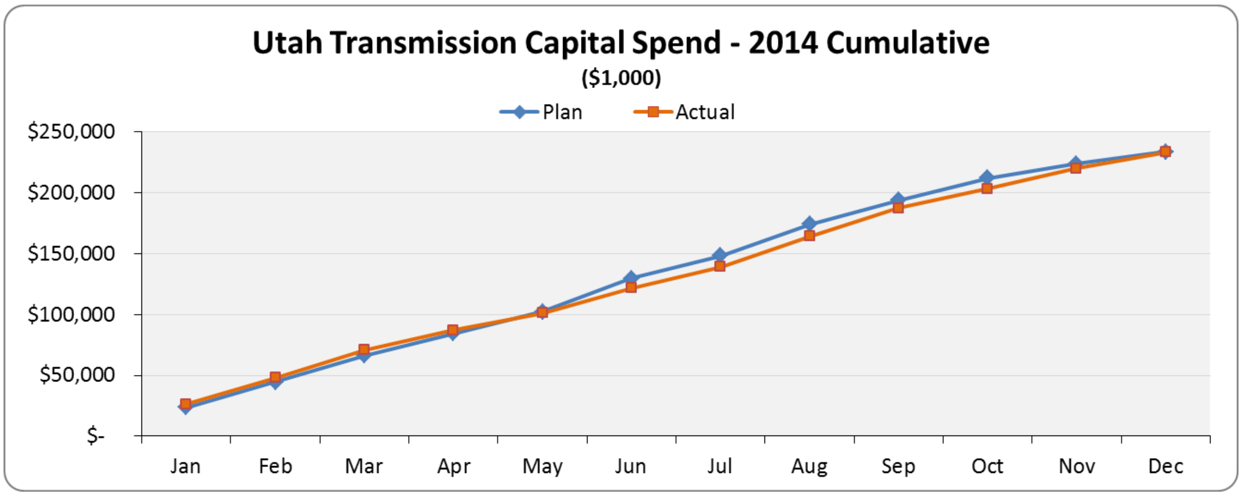


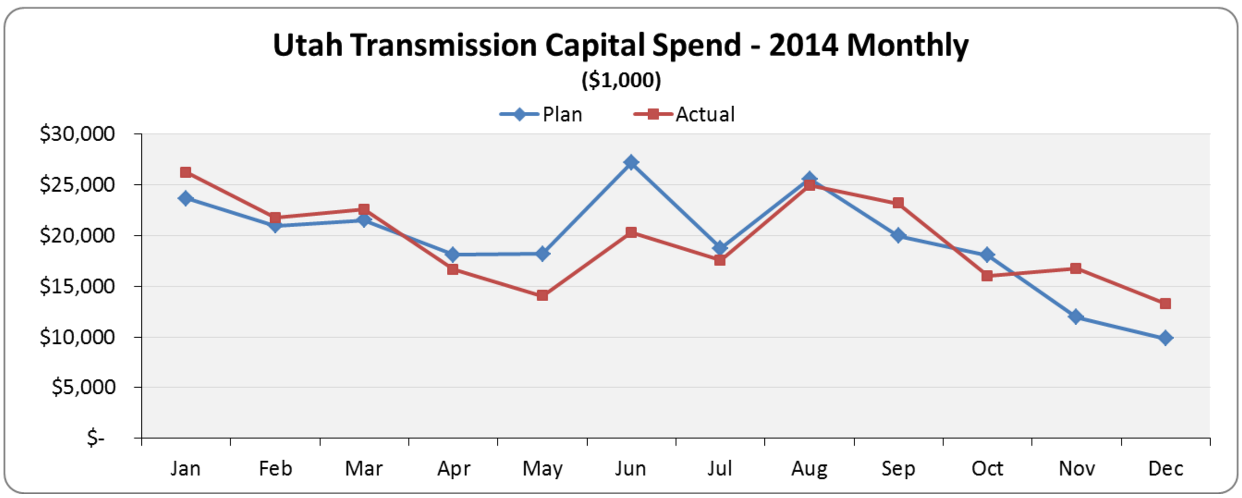


4.2 Capital Spending – Transmission

January –December 2014

Investment	Actuals ($M)	Plan ($M)	Significant Variances
1. Mandated	$27.8	$23.6	Mandated NERC reliability, national/regional regulatory (WECC, FERC, etc.), and right-of-way renewals over plan, (+$6.1M); mandated road relocations under plan, (-$1.5M).
2. New Connect	$2.9	$0.3	Commercial new connect over plan, (+$2.7M). *(Note: Actuals include $2.7M transfer from distribution to transmission for prior year City Creek project costs, Mar-2014).*
3. Local Transmission System Reinforcements	$8.8	$6.7	Local subtransmission reinforcement over plan, (+$1.7M).
4. Main Grid Reinforcements / Interconnections	$34.0	$46.1	Carbon Plant Replacement (-$6.6M), Highland Sub-Lehi Rebld for Network Cust (-$4.2M) and Mona Sub Series Reactor (-$1.1M) under plan.
5. Energy Gateway Transmission	$147.8	$143.6	Sigurd Red Butte Crystal Line (+$3.6M) and Populus-Terminal Line (+$1.3M) over plan; Mona-Oquirrh Line (-$0.8M) under plan. *(Note: Populus-Terminal Line project crosses state line--acctg procedures assign all plan $ to ID; capital spending report includes $1.3M in UT expenditures.)*
6. Replacement	$11.5	$13.5	Replacements for storm & casualty, substation bushings/glass/other, and overhead transmission poles over plan, (+$2.3M); replacements for substation transformers under plan, (-$4.8M).
7. Upgrade & Modernize	$0.4	$0.0	
Total	**$233.2**	**$233.7**	





4.3 New Connects

	2013	2014																	
	Jan - Dec 2013	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jan - Jun 2013	Jul	Aug	Sep	Q3 Total	Oct	Nov	Dec	Q4 Total	YEAR TO DATE
Residential																			
UT South	741	55	34	49	138	48	40	70	158	296	66	69	68	203	54	59	50	163	662
UT North/Metro	4,382	436	285	240	961	352	440	490	1,282	2,243	309	383	457	1,149	378	356	347	1,081	4,473
UT Central	5,634	539	355	454	1,348	433	455	473	1,361	2,709	527	575	701	1,803	930	743	707	2,380	6,892
Total Residential	**10,757**	**1,030**	**674**	**743**	**2,447**	**833**	**935**	**1,033**	**2,801**	**5,248**	**902**	**1,027**	**1,226**	**3,155**	**1,362**	**1,158**	**1,104**	**3,624**	**12,027**
Commercial																			
UT South	204	12	13	16	41	16	30	13	59	100	10	14	20	44	23	14	20	57	201
UT North/Metro	626	44	45	37	126	46	47	49	142	268	60	60	56	176	66	59	100	225	669
UT Central	653	53	35	55	143	51	57	51	159	302	67	75	73	215	110	103	172	385	902
Total Commercial	**1,483**	**109**	**93**	**108**	**310**	**113**	**134**	**113**	**360**	**670**	**137**	**149**	**149**	**435**	**199**	**176**	**292**	**667**	**1,772**
Industrial																			
UT South	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	1	3	3
UT North/Metro	6	-	-	-	-	1	-	-	1	1	-	-	-	-	-	1	28	29	30
UT Central	5	1	3	1	5	1	2	-	3	8	-	-	-	-	-	1	3	4	12
Total Industrial	**18**	**1**	**3**	**1**	**5**	**2**	**2**	**-**	**4**	**9**	**-**	**-**	**-**	**-**	**-**	**4**	**32**	**36**	**45**
Irrigation																			
UT South	74	2	1	2	5	12	7	4	23	28	5	7	3	15	-	-	2	2	45
UT North/Metro	5	-	-	1	1	-	-	-	-	1	1	1	-	2	-	1	1	2	5
UT Central	18	1	-	3	4	4	-	-	4	8	-	2	2	4	1	1	-	2	14
Total Irrigation	**97**	**3**	**1**	**6**	**10**	**16**	**7**	**4**	**27**	**37**	**6**	**10**	**5**	**21**	**1**	**2**	**3**	**6**	**64**
TOTAL New Connects																			
UT South	1,026	69	48	67	184	76	77	87	240	424	81	90	91	262	77	75	73	225	911
UT North/Metro	5,019	480	330	278	1,088	399	487	539	1,425	2,513	370	444	513	1,327	444	417	476	1,337	5,177
UT Central	6,310	594	393	513	1,500	489	514	524	1,527	3,027	594	652	776	2,022	1,041	848	882	2,771	7,820
TOTAL New Connects	**12,355**	**1,143**	**771**	**858**	**2,772**	**964**	**1,078**	**1,150**	**3,192**	**5,964**	**1,045**	**1,186**	**1,380**	**3,611**	**1,562**	**1,340**	**1,431**	**4,333**	**13,908**

Utah South region includes Moab, Price, Cedar City and Richfield

Utah North/Metro region includes SLC Metro, Ogden and Layton

Utah Central region includes American Fork, Vernal, Tooele, Jordan Valley and Park City

Region areas are subject to change for operational purposes and may differ from historical reporting

New Connects report reflects the volume of all new connections in the system in the reporting period, which may include temporary connections that are subsequently removed in future periods; therefore, it is not necessarily an auditable count of new permanent connections for the reporting period.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH
Tree Program Reporting
January 1, 2014 through December 31, 2014
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2014-12/31/2014 Miles Planned	1/1/2014-12/31/2014 Actual Miles	01/01/2014-12/31/2014 Ahead/ Behind	1/1/2014-12/31/2014 % 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	10,871	3,623	3,993	370	110.2%	3,624	3,993	369	110.2%
AMERICAN FORK	806	269	174	-95	64.7%	269	174	-95	64.8%
CEDAR CITY	1,326	442	708	266	160.2%	442	708	266	160.2%
JORDAN VALLEY	774	258	333	75	129.1%	258	333	75	129.1%
LAYTON	281	94	27	-67	28.7%	94	27	-67	28.8%
MOAB	955	318	172	-146	54.1%	318	172	-146	54.0%
OGDEN	879	293	279	-14	95.2%	293	279	-14	95.2%
PARK CITY	529	176	218	42	123.9%	176	218	42	123.6%
PRICE	590	197	321	124	162.9%	197	321	124	163.2%
RICHFIELD	1,346	449	247	-202	55.0%	449	247	-202	55.1%
SL METRO	1,180	393	514	121	130.8%	393	514	121	130.7%
SMITHFIELD	757	252	311	59	123.4%	252	311	59	123.2%
TOOELE	481	160	92	-68	57.5%	160	92	-68	57.4%
TREMONTON	728	243	519	276	213.6%	243	519	276	213.9%
VERNAL	239	79	78	-1	98.7%	80	78	-2	97.9%

Distribution

Distribution cycle $/tree:	$89.58
Distribution cycle $/mile:	$2,847
Distribution cycle removal %	20.89%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,379	601	875	274	6,653	1.043

Transmission $/mile:	$3,878

Current distribution cycle begin 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, 2014 through December 31, 2014
Column c: Actual overhead distribution pole miles worked during the period January 1 2014 through December 31, 2014
Column d: Miles ahead or behind for the period January 1, 2014 through December 31, 2014 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2014 through December 31, 2014 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2014 through December 31, 2016
Column g: Actual overhead distribution pole miles worked during the period January 1 2014 through December 31, 2016
Column h: Miles ahead or behind for the period January 1, 2014 through December 31, 2016 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2014 through December 31, 2016 ((column g÷f)×100). Max = 100%

5.2 Budget

UTAH

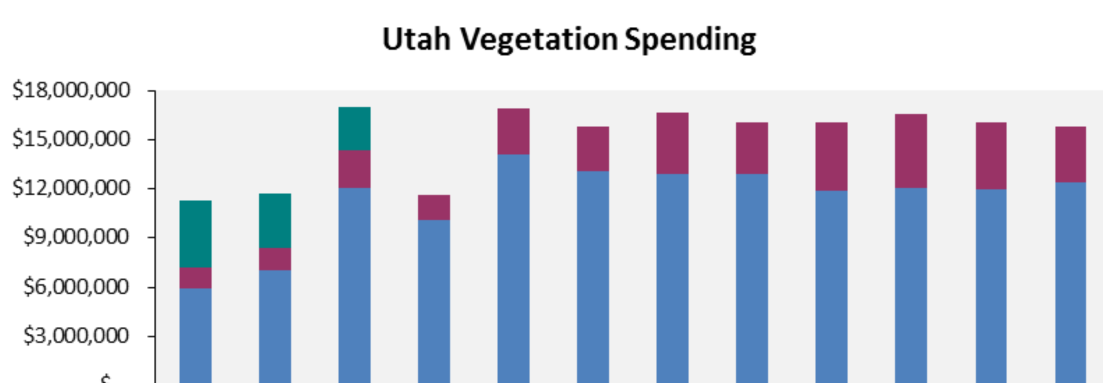
Tree Program Reporting

	CY2015	CY2016	CY2017
Distribution			
Tree Budget	$11,910,000	$11,910,000	$11,910,000
Transmission			
Tree Budget	$3,882,031	$3,882,031	$3,882,031
Total Tree Budget	**$15,792,031**	**$15,792,031**	**$15,792,031**

Calendar year 2014	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$1,054,710	$1,028,962	$25,748	$301,982	$329,778	-$27,796
Feb	$849,236	$890,921	-$41,685	$196,325	$285,951	-$89,626
Mar	$1,243,363	$982,947	$260,416	$304,173	$315,170	-$10,997
Apr	$1,176,415	$1,028,962	$147,453	$275,078	$329,778	-$54,700
May	$925,468	$982,948	-$57,480	$235,710	$315,169	-$79,459
Jun	$1,014,589	$982,947	$31,642	$294,004	$315,170	-$21,166
Jul	$943,311	$982,948	-$39,637	$324,178	$315,169	$9,009
Aug	$945,539	$982,948	-$37,409	$353,152	$315,169	$37,983
Sep	$1,039,350	$982,947	$56,403	$264,069	$315,170	-$51,101
Oct	$1,241,561	$1,074,975	$166,586	$224,635	$344,387	-$119,752
Nov	$903,556	$844,908	$58,648	$272,778	$271,341	$1,437
Dec	$1,065,952	$1,028,961	$36,991	$314,575	$329,779	-$15,204
Total	**$12,403,052**	**$11,795,374**	**$607,678**	**$3,360,658**	**$3,782,031**	**-$421,373**

Average # Tree Crews on Property (YTD) **64**

5.2.1 Vegetation Historical Spending



	FY04	FY05	FY06	Apr-Dec'06	CY07	CY08	CY09	CY10	CY11	CY12	CY13	CY14
Miscellaneous	4,127,062	3,306,952	2,666,318									
Transmission	1,235,702	1,351,143	2,273,513	1,489,985	2,809,622	2,777,814	3,716,266	3,180,955	4,245,089	4,483,668	4,070,233	3,360,658
Distribution	5,934,507	7,070,339	12,072,30	10,107,31	14,097,44	13,053,51	12,934,36	12,866,26	11,837,42	12,037,62	11,991,60	12,403,05

Miscellaneous = storm and casualty, line extension work, special request projects, administrative.

6 Appendix

6.1 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[11] 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).

[11] 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.