ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

October 30, 2025

***VIA ELECTRONIC FILING***

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

Attention: Gary Widerburg
Commission Administration

RE: **Docket No. 25-035-29**
Rocky Mountain Power 2025 Mid-Year Service Quality Report

In compliance with the Commission's June 11, 2009, order in Docket No. 08-035-55 and December 20, 2016, order in Docket Nos. 13-035-01 and 15-035-72, and pursuant to the requirements of Rule R746-313, PacifiCorp d.b.a. Rocky Mountain Power ("RMP" or "Company") submits the Service Quality Review Report for the period January through June, 2025.

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

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
max.backlund@pacificorp.com

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

Informal inquiries may be made to Max Backlund at max.backlund@pacificorp.com.

Sincerely,

Jana Saba

Jana Saba
Director, Regulation and Regulatory Operations

**CERTIFICATE OF SERVICE**

Docket No. 25-035-29

I hereby certify that on October 30, 2025, a true and correct copy of the foregoing was served by electronic mail to the following:

**Utah Office of Consumer Services**

| | |
|---|---|
| Michele Beck | mbeck@utah.gov |
| | ocs@utah.gov |

**Division of Public Utilities**

dpudatarequest@utah.gov

**Assistant Attorney General**

| | |
|---|---|
| Patricia Schmid | pschmid@agutah.gov |
| Robert Moore | rmoore@agutah.gov |
| Patrick Grecu | pgrecu@agutah.gov |

**Rocky Mountain Power**

| | |
|---|---|
| Data Request Response Center | datarequest@pacificorp.com |
| Jana Saba | jana.saba@pacificorp.com<br>utahdockets@pacificorp.com |
| Max Backlund | max.backlund@pacificorp.com |

Rick Loy
Coordinator, Regulatory Operations

# Utah

# Service Quality Review

2025 Mid-Year Report

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

# Table of Contents

# Background

In the early 2000s, Rocky Mountain Power developed its Customer Service Standards and Service Quality Measures by benchmarking against industry reliability and customer service standards. Where no industry standards existed, Rocky Mountain Power created its own metrics, targets and reporting methods.

In Docket No. 20-035-22, the Division of Public Utilities (DPU) reviewed Rocky Mountain Power's 2019 service quality and recommended the Public Service Commission of Utah (Commission) establish a work group to review RMP's reliability baseline standards related to SAIDI and SAIFI. The Commission accepted this recommendation and directed RMP and DPU to convene a work group, open to interested parties, to examine and make recommendations on RMP's reliability baseline standards. The work group met and discussed new baseline performance standards, which are reflected in the following report.

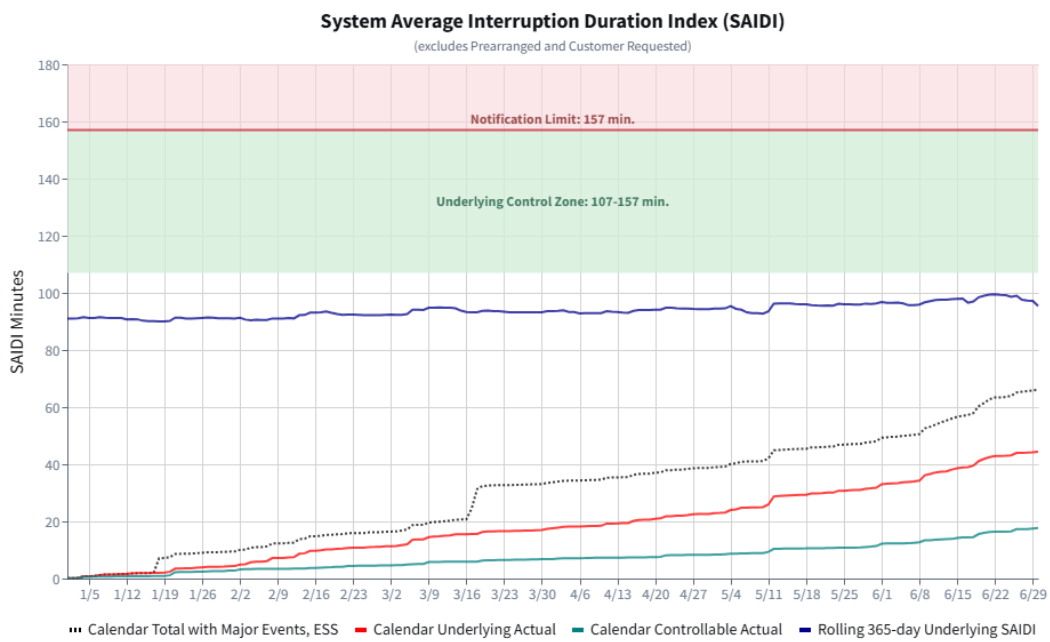
# 1 Reliability Performance

The underlying performance control zone limits are set from 107-157 minutes for SAIDI and 0.9-1.2 events for SAIFI. The notification limits are set at 157 minutes for SAIDI and 1.2 events for SAIFI indicating performance that exceeds the expected range of performance. Sections 1.1 and 1.2 overview annual results related to control zones and notification limits. Section 1.3 covers major and significant events for customers. Outage response performance is in section 1.4, CAIDI performance in section 1.5, and wildfire mitigation impact on reliability in section 1.6.

## 1.1 System Average Interruption Duration Index (SAIDI)

| SAIDI | Reporting Period |
|---|---|
| **Total[1]** | **68.2** |
| **Major Events** | 16.1 |
| **Enhanced Safety Settings (ESS)[2]** | 5.6 |
| **Emergency De-energization[3]** | 0.0 |
| **Public Safety Power Shutoff (PSPS)[4]** | 2.1 |
| **Underlying** | **44.4** |

| SAIDI | Reporting Period |
|---|---|
| **Underlying** | **44.4** |
| **Controllable[5] Distribution** | 17.7 |
| **Non-controllable Distribution** | 26.7 |

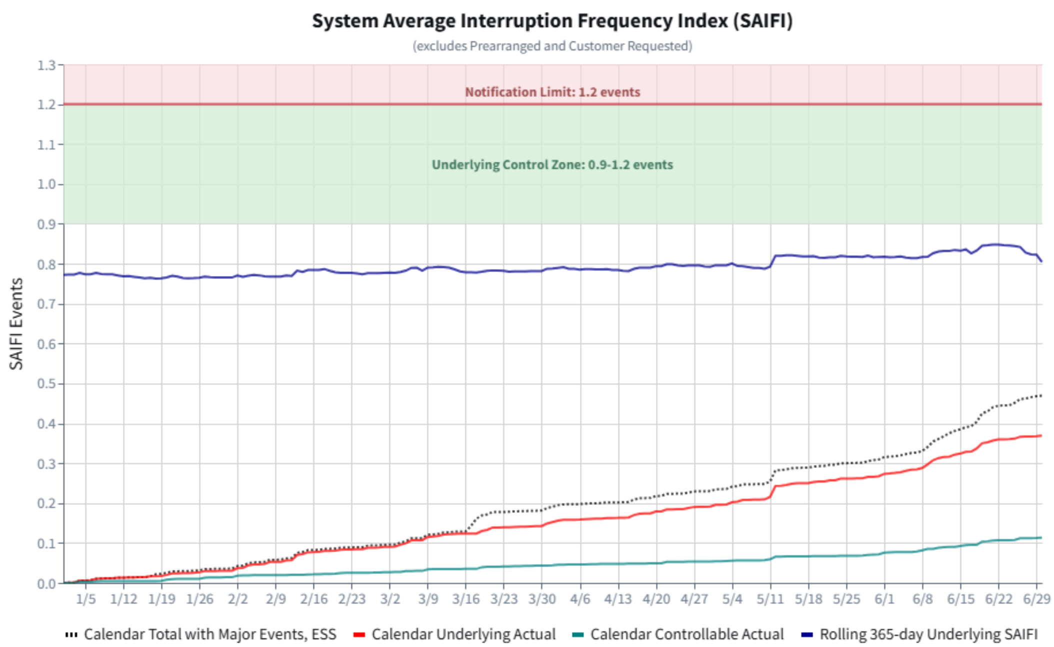



[1] Total SAIDI = Underlying + Enhanced Safety Settings (ESS) + Emergency De-energization + Major Events + Public Safety Power Shutoff (PSPS)
[2] Enhanced Safety Settings (ESS) are more sensitive settings implemented to reduce the risk of wildfires during fire season as described in Section 1.6.
[3] Wildfire emergency de-energization was implemented at the beginning of 2024. Additional details of this mitigation effort are described in Section 1.6.
[4] Public Safety Power Shutoff (PSPS) is employed to prevent wildfires or other hazards during extreme weather conditions.
[5] Controllable categories include Animals, Bird Mortality (non-protected and protected species), Bird Nest, Bird Suspected-No Mortality, Bad Order Equipment, Deterioration or Rotting, Faulty Install, Overload, and Trees – Trimmable.

## 1.2 System Average Interruption Frequency Index (SAIFI)

| SAIFI | Reporting Period |
|---|---|
| **Total** | **0.473** |
| **Major Events** | 0.039 |
| **Enhanced Safety Settings (ESS)** | 0.062 |
| **Emergency De-energization** | 0.000 |
| **Public Safety Power Shutoff (PSPS)** | 0.003 |
| **Underlying** | **0.369** |

| SAIFI | Reporting Period |
|---|---|
| **Underlying** | **0.369** |
| **Controllable Distribution** | 0.114 |
| **Non-controllable Distribution** | 0.255 |



## 1.3 Major and Significant Event Days

In the current reporting period, the Company experienced two statewide major events,[6] zero regional major events, and four significant events.[7] Rocky Mountain Power includes regional major events into its analysis to address statistical outliers that may not appear at the state level. Regional major events do not necessarily escalate to state-level major events. When this occurs, the Company will submit a major event filing for the region if the event surpasses the regional threshold.

**State Major Events**

| Major Events | | | | |
|---|---|---|---|---|
| **Date** | **Cause** | **Status** | **Docket** | **SAIDI** |
| **January 18, 2025[8]** | Interference – Vehicle Accident | **Approved** | 25-035-11 | 5.11 |
| **March 17-18, 2025** | Weather | **Approved** | 25-035-28 | 11.00 |
| **Total** | | | | **16.11** |

January 18, 2025
On January 18, 2025, a vehicle accident in Park City, Utah, caused a utility pole to fall, bringing down additional poles and obstructing the roadway with power lines. Crews isolated the affected section, re-energized most customers and replaced damaged poles with support from surrounding areas. Outage durations were prolonged due to a tie that was removed related to a Fire High Consequence Area project, impacting restoration efforts at the Silver Creek substation. The major event affected 5,554 customers.

March 17-18, 2025
During the afternoon of March 17 through the morning of March 19, Utah experienced two large-impacting outage events that exceeded the major event threshold at the state level. A cold front moved across Northern Utah in the afternoon of March 17 and continued into March 18, 2025. The cold front brought winds and heavy wet snow impacting the Salt Lake, Utah and Tooele Valleys. The event impacted 23,388 customers with outage durations ranging from 12 minutes to 14 hours 59 minutes.

In the evening of March 18, a pole on the 345kV Pinto to Four Corners transmission line failed causing widespread outages to customers in Southeastern Utah. The event impacted 11,706 customers including bulk power to Monticello City and Blanding City municipal utilities, the Navajo Nation, and one major customer. Outage duration for the event ranged from 8 hours 34 minutes to 8 hours 52 minutes.

The major event impact from these two events totaled 35,367 customers across the state.

[6] A Major Event (ME) is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2022) based on the 2.5 beta methodology. The values used for the reporting period are shown below:

| Effective Date | Customer Count | ME Threshold SAIDI | ME Customer Minutes Lost |
|---|---|---|---|
| 1/1-12/31/2025 | 1,054,136 | 3.83 | 4,036,570 |

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

[8] SAIDI modified slightly from 5.21 to 5.11 and SAIFI from 0.003 to 0.005 due to data cleanup after the event.

### Regional Major Events

Beginning in 2020, Rocky Mountain Power began categorizing regions where outages in a diverse operating area can be identified as statistical outliers, which would otherwise be hidden by the statistical weighting of some districts. This is in accordance with IEEE Guide 1366-2022 which notes, "[the purpose of major event classification] is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events."[9] Starting in 2024, the Company began excluding regional major events from underlying metrics in accordance with the Commission Order issued December 12, 2023, under Docket 23-035-21.

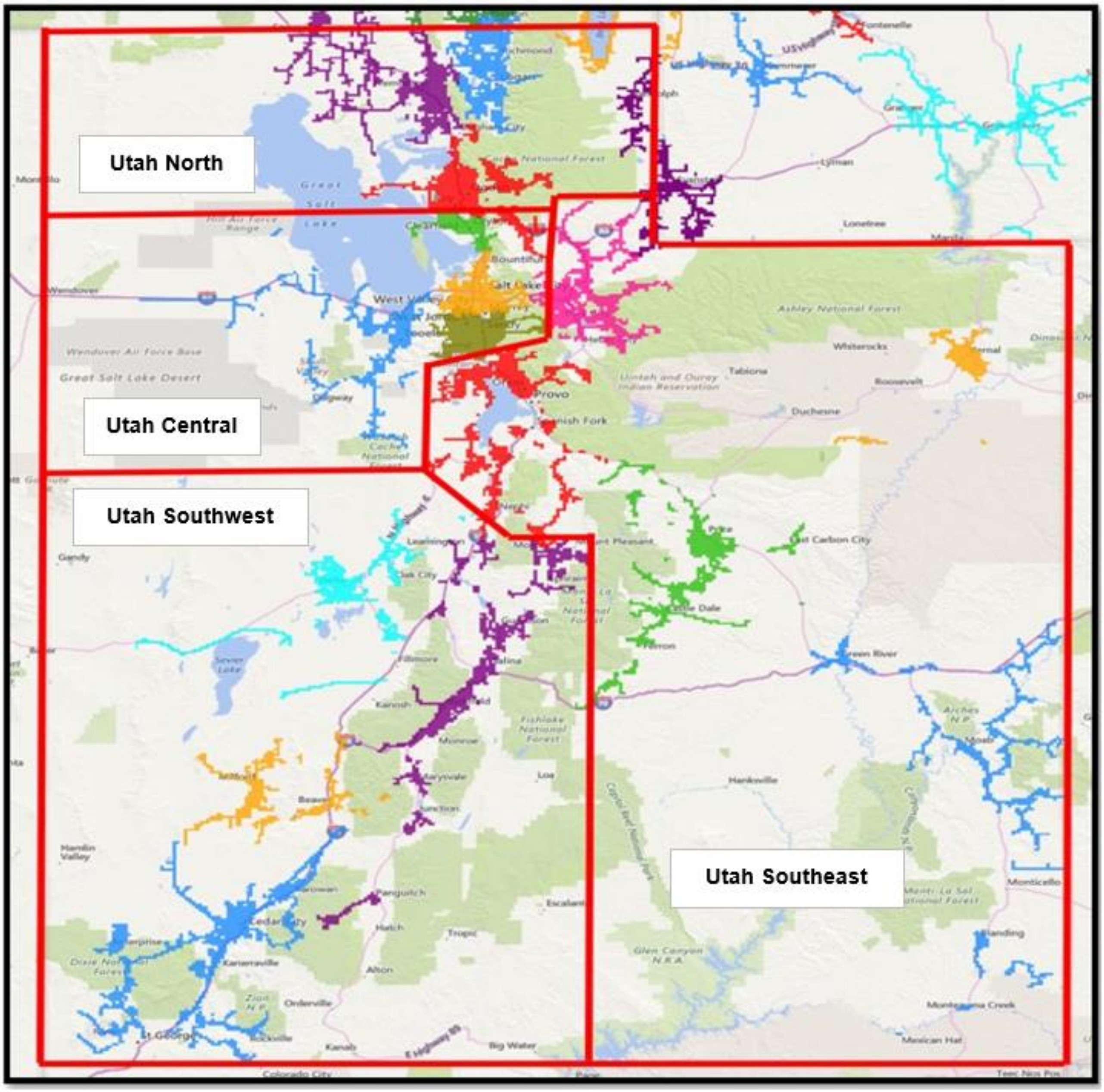
No regional major events were recorded during the reporting period.

### Major Event Thresholds

To improve identification of major events and to accurately represent the reliability performance at regional and State level, the company has subdivided the State into five major event reporting areas to ensure that major events are more equally represented in rural versus urban population areas by eliminating statistical anomalies that may occur in local areas. Statistically, events that exceed the threshold for major event day (TMED) are a result of stresses beyond what is normally expected. By capturing these events at a regional level, it would remove the statistical anomalies from these regions and provide a more consistent representation of the electric reliability at the State and local level. The proposed reliability reporting areas, and their respective TMED values for 2025, are shown in the table below.

| Reliability Reporting Area | Total Customer Count | Threshold for Major Day Event (TMED) | Customer Minutes Lost (CML) |
|---|---|---|---|
| Utah North | 166,944 | 16.93 | 2,825,733 |
| Utah Central | 605,903 | 4.78 | 2,895,325 |
| Utah Southeast | 215,270 | 12.33 | 2,654,489 |
| Utah Southwest | 66,019 | 16.36 | 1,079,963 |
| **State of Utah** | **1,054,136** | **3.83** | **4,036,570** |

[9] Institute of Electrical and Electronics Engineers. *IEEE Guide for Electric Power Distribution Reliability Indices.* IEEE Std 1366-2022 (New York: IEEE, 2022), 20.


Utah North
Utah Central
Utah Southwest
Utah Southeast

**Significant Events**

Significant event days add substantially to year-on-year cumulative performance results; fewer significant event days generally result in better reliability for the reporting period while more significant event days generally mean poorer reliability results. During the period, four significant event days were recorded, which account for 7.34 SAIDI minutes, or about 16.5% of the reporting period's underlying 44.4 SAIDI minutes.

| Significant Event Days | | | | | | |
|---|---|---|---|---|---|---|
| **Dates** | **Cause: General Description** | **Operating District** | **Underlying SAIDI** | **Underlying SAIFI** | **% of Total Underlying SAIDI (44.4)** | **% of Total Underlying SAIFI (0.369)** |
| March 6, 2025 | Loss of Transmission Line | Garden City | 1.57 | 0.007 | 3.5% | 2.0% |
| May 12, 2025 | Loss of Transmission Line | SLC Metro | 2.74 | 0.026 | 6.2% | 7.1% |
| June 9, 2025 | Loss of Substation | SLC Metro | 1.89 | 0.009 | 4.3% | 2.4% |
| June 19, 2025 | Deterioration or Rotting | Jordan Valley | 1.14 | 0.010 | 2.5% | 2.7% |
| | | **TOTAL** | **7.34** | **0.052** | **16.5%** | **14.2%** |

## 1.4 Restore Service to 80% of Customers within 3 Hours

The table below shows the average time, during the reporting period, for outage restoration. Through the first half of the year, January and April stand out as particularly difficult months. January outages were primarily driven by third-party dig-in incidents, underground cable failures and vehicle accidents. In April, underground cable failure and vehicle accidents contributed to longer outage durations.

| RESTORATIONS WITHIN 3 HOURS | | | | | |
|---|---|---|---|---|---|
| **Reporting Period Cumulative = 82%** | | | | | |
| January | February | March | April | May | June |
| 72% | 81% | 83% | 79% | 87% | 82% |

## 1.5 CAIDI Performance

| CAIDI (Average Outage Duration) | |
|---|---|
| Underlying Performance | 120 minutes |
| Total Performance | 144 minutes |

## 1.6 Wildfire Situational Awareness and Operational Practice Impact

As part of the Company's Wildfire Mitigation efforts, approved by the commission in 2020 (Docket No. 20-035-28), operational practices have been implemented to mitigate wildfire risk.

To reduce wildfire risk, the Company has implemented fast-trip protection settings, referred to as Enhanced Safety Settings (ESS)[10]. While ESS improves wildfire mitigation, these settings may affect customer reliability. Outages on circuits with ESS-enabled protection are tracked separately from underlying SAIDI values.

Beginning in 2024, Rocky Mountain Power also implemented wildfire emergency de-energizations when active fires advance towards company assets. These actions are used to ensure the safety of the public, emergency personnel, and Company employees and to mitigate the risk of additional ignitions. Power restoration efforts begin once field assessments or emergency responders confirm that conditions are safe to re-energize. Through June 2025, there were no emergency de-energization events recorded in Utah.

A Public Safety Power Shutoff (PSPS) is a precautionary measure used to mitigate wildfire risk by temporarily de-energizing lines during periods of extreme fire danger. Because these conditions may not be visible to the public, the Company relies on a combination of field observations, weather forecasts, and specific thresholds, such as high winds, low humidity, and critically dry vegetation, to determine when a PSPS event is necessary.

| | SAIDI | SAIFI | CAIDI |
|---|---|---|---|
| **Enhanced Safety Settings (ESS)** | 5.6 | 0.062 | 90 |
| **Emergency De-energization** | 0.0 | 0.000 | N/A |
| **Public Safety Power Shutoff (PSPS)** | 2.1 | 0.003 | 662 |

**Public Safety Power Shutoff Events**

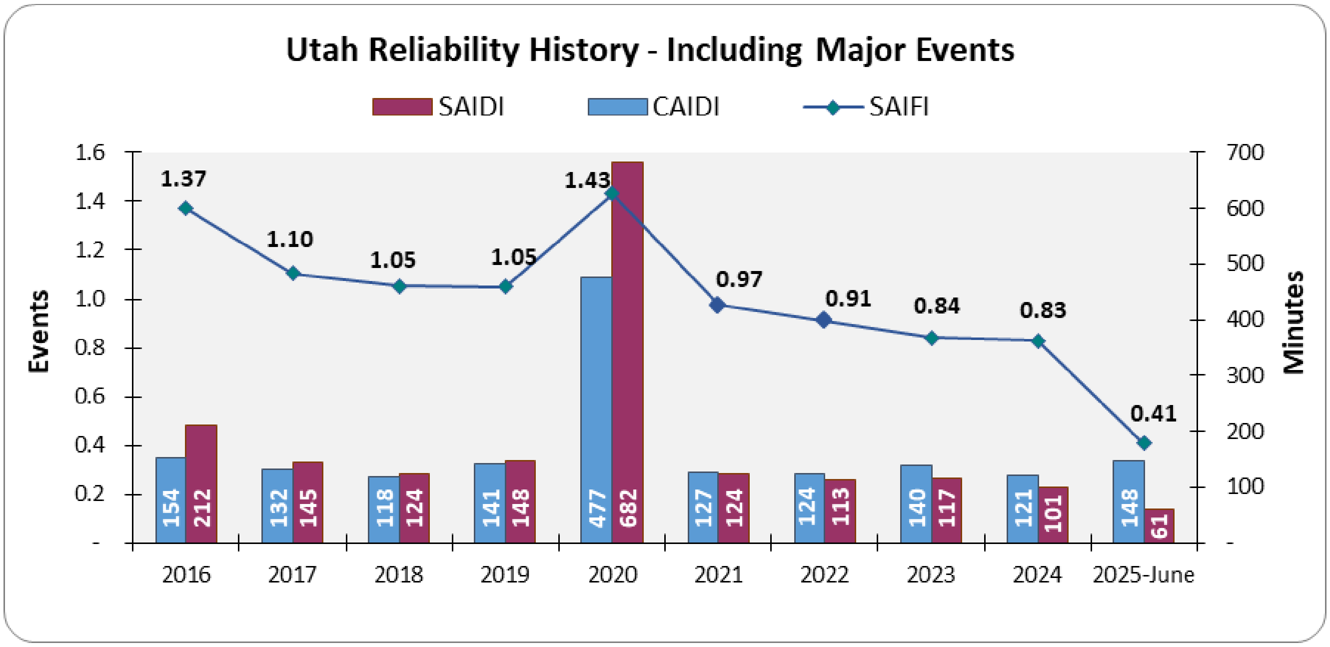
June 21, 2025
On June 16, 2025, company meteorologists forecasted extreme fire weather conditions for June 21, 2025, in parts of southwestern Utah, prompting preparations for a Public Safety Power Shutoff. Hot, dry weather and high winds up to 74 miles per hour were expected, and 6,342 customers were identified as potentially impacted. The department operations center and emergency coordination center were activated, and communications began 72 hours in advance. A community resource center was set up, and all vulnerable customers were contacted. On June 21, 2025, at 5:47 a.m., a total of 3,374 customers were de-energized across 19 circuits, with full power restoration completed that night. No safety incidents occurred.

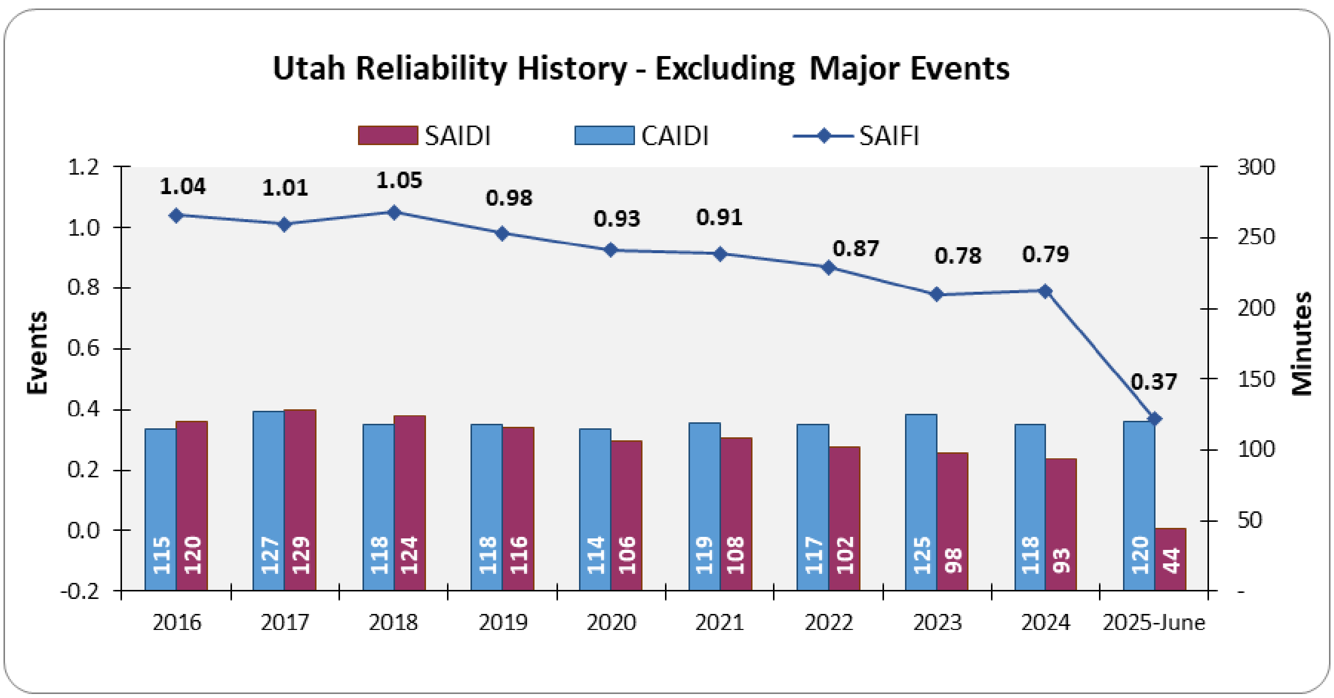
[10] Starting in 2024, Elevated Fire Risk (EFR) was renamed to Enhanced Safety Settings (ESS).

# 2 Reliability History

Section 2.1 shows the historical reliability performance, while sections 2.2 and 2.3 illustrate 365-day rolling trends, and updated baselines are detailed in section 2.3.

## 2.1 Utah Reliability Historical Performance[11]




[11] The large increase of SAIDI, SAIFI, and CAIDI in 2020 is due to the Labor Day catastrophic event that was caused by downslope winds along the Wasatch Front. For more information on this major event see Docket No. 21-035-15.

## 2.2 Controllable, Non-Controllable and Underlying Performance Review

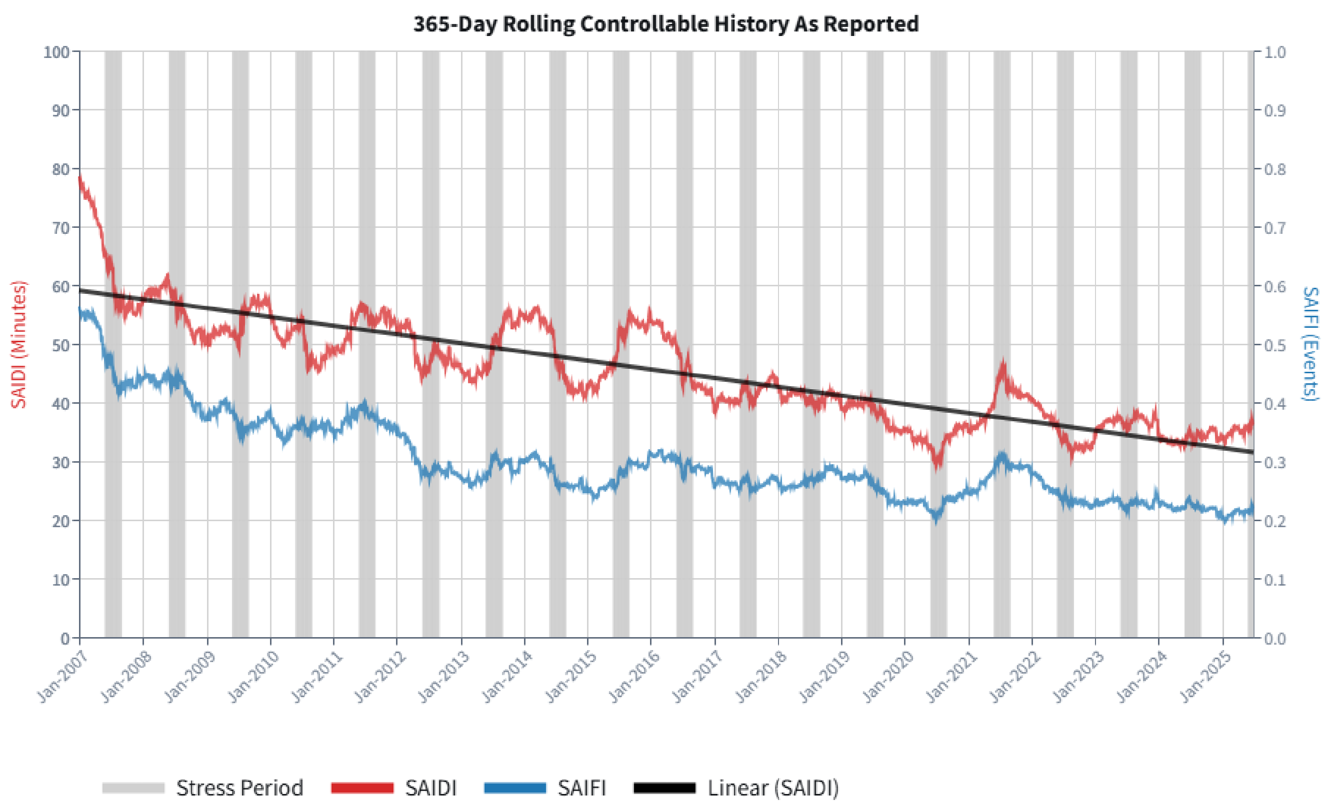
In 2008, the Company introduced a refined categorization of outage causes. This categorization, known as Controllable Distribution Outages, recognizes that certain types of outages can be effectively prevented. For instance:

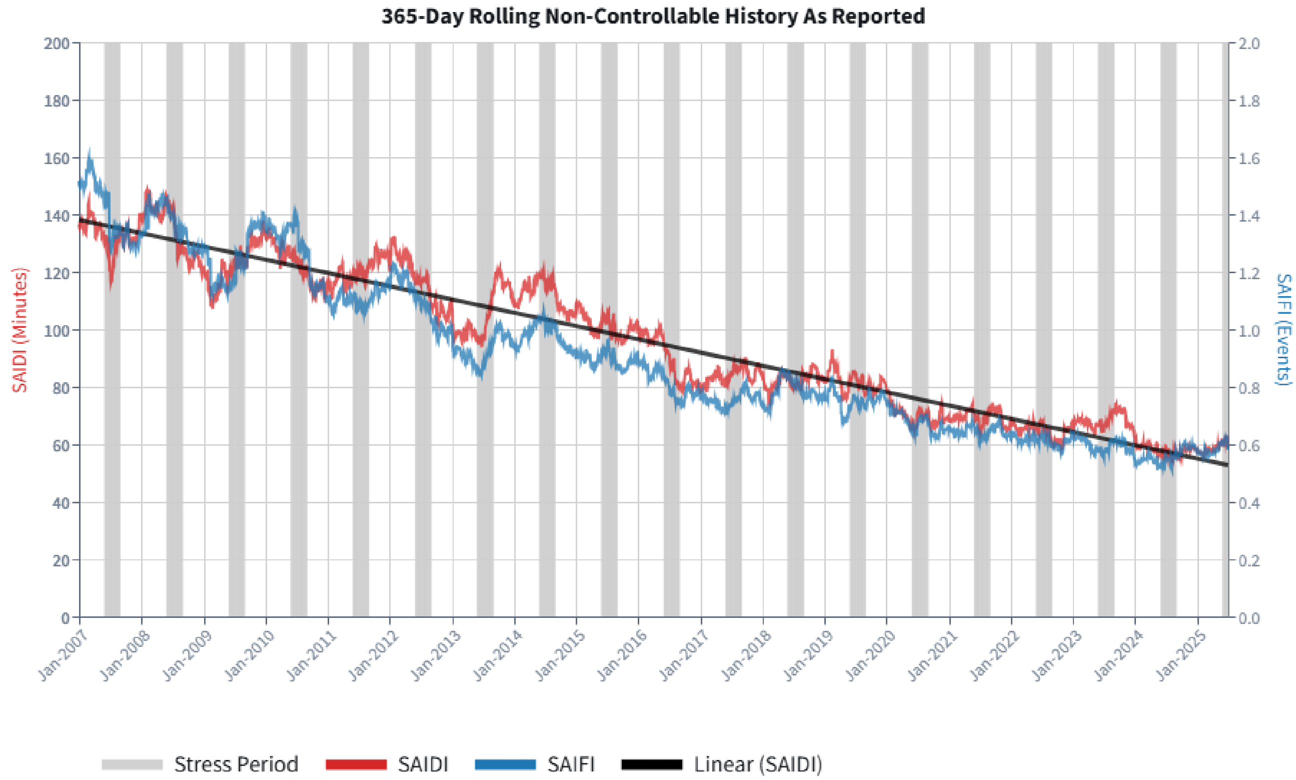
- Animal-caused or equipment failure interruptions have a less random nature than lightning-caused interruptions.
- Engineers can develop plans to mitigate against controllable distribution outages and provide better future reliability at the lowest possible cost.

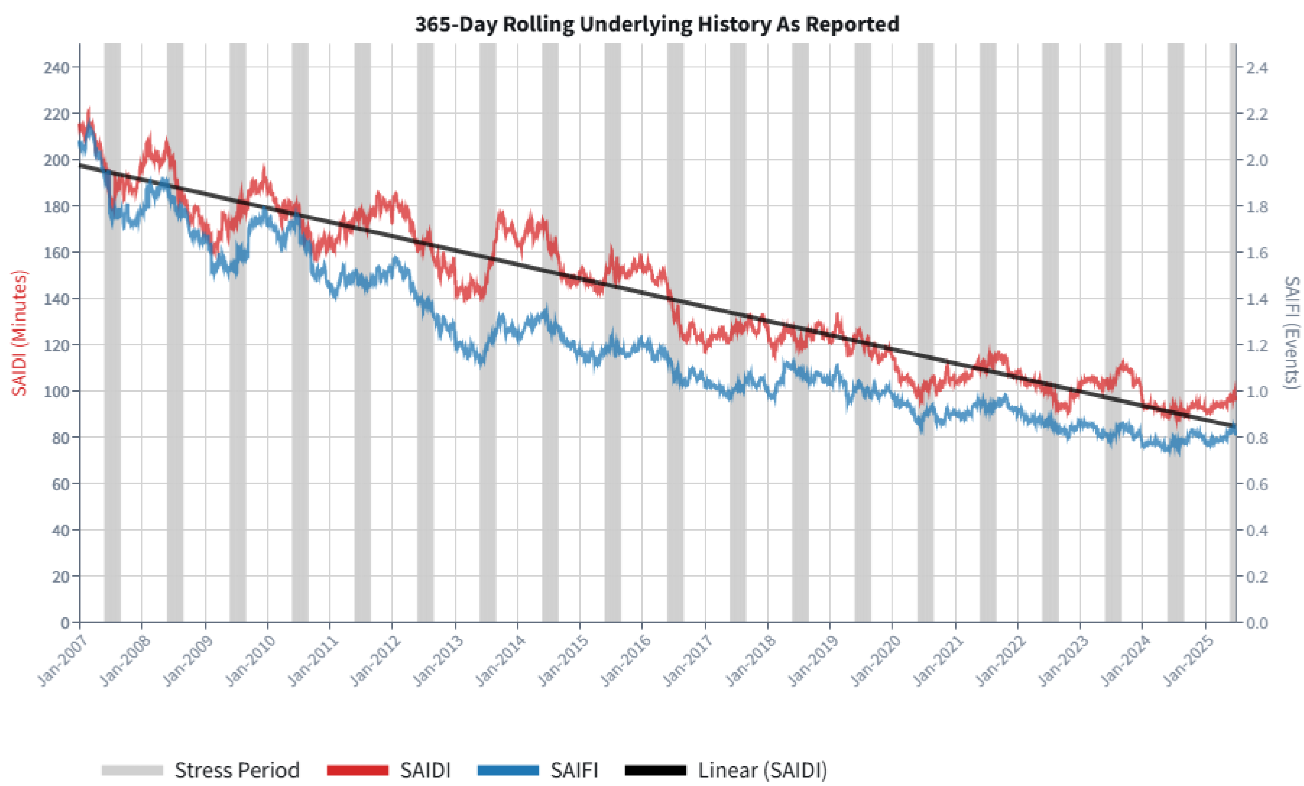
Despite this focus on controllable outages, the Company remains committed to addressing non-controllable outages. Efforts include:

- Enhancing resilience to extreme weather through programs like the visual assurance program.
- Understanding the impact of supply disruptions on customers and delivering appropriate improvements.
- Utilizing web-based notifications to react promptly to declining reliability trends, regardless of the outage cause.

This approach ensures overall reliability and continuous improvement.



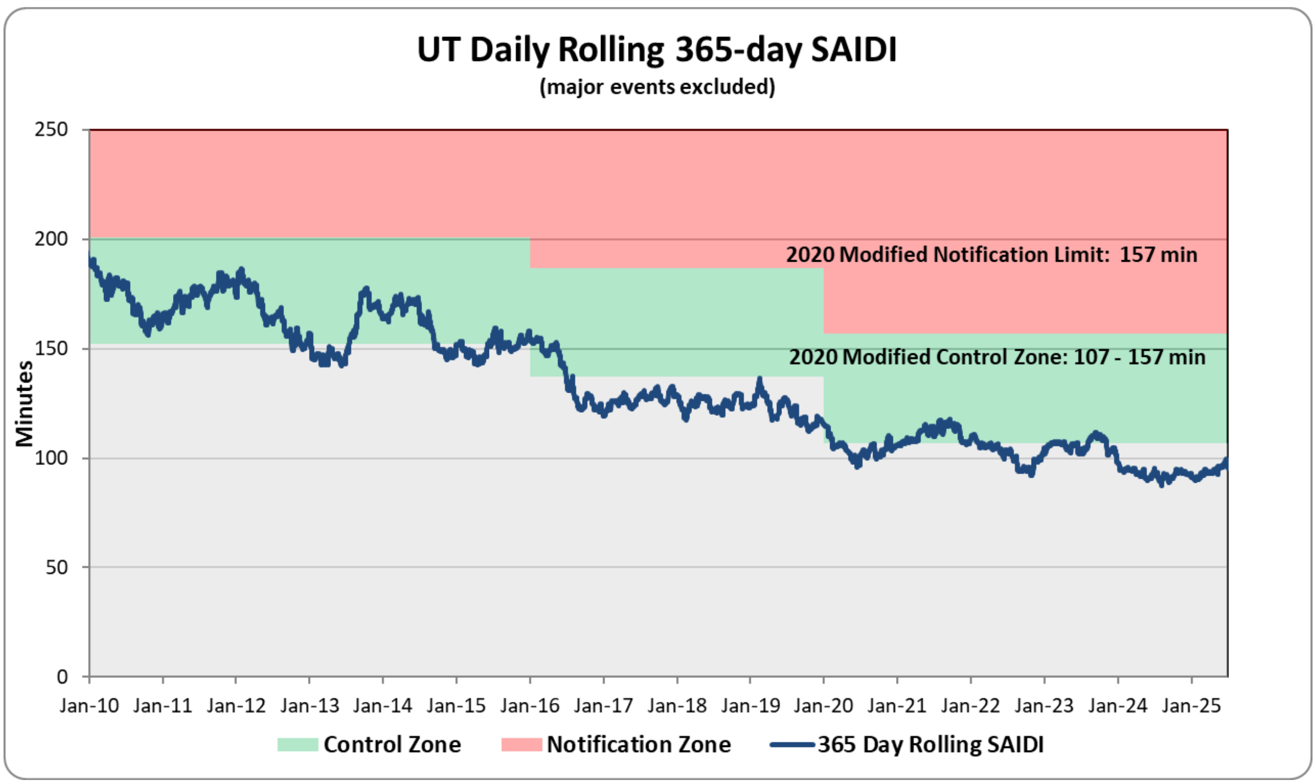

365-Day Rolling Non-Controllable History As Reported
SAIDI (Minutes)
SAIFI (Events)
0
20
40
60
80
100
120
140
160
180
200
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Jan-2019
Jan-2020
Jan-2021
Jan-2022
Jan-2023
Jan-2024
Jan-2025
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

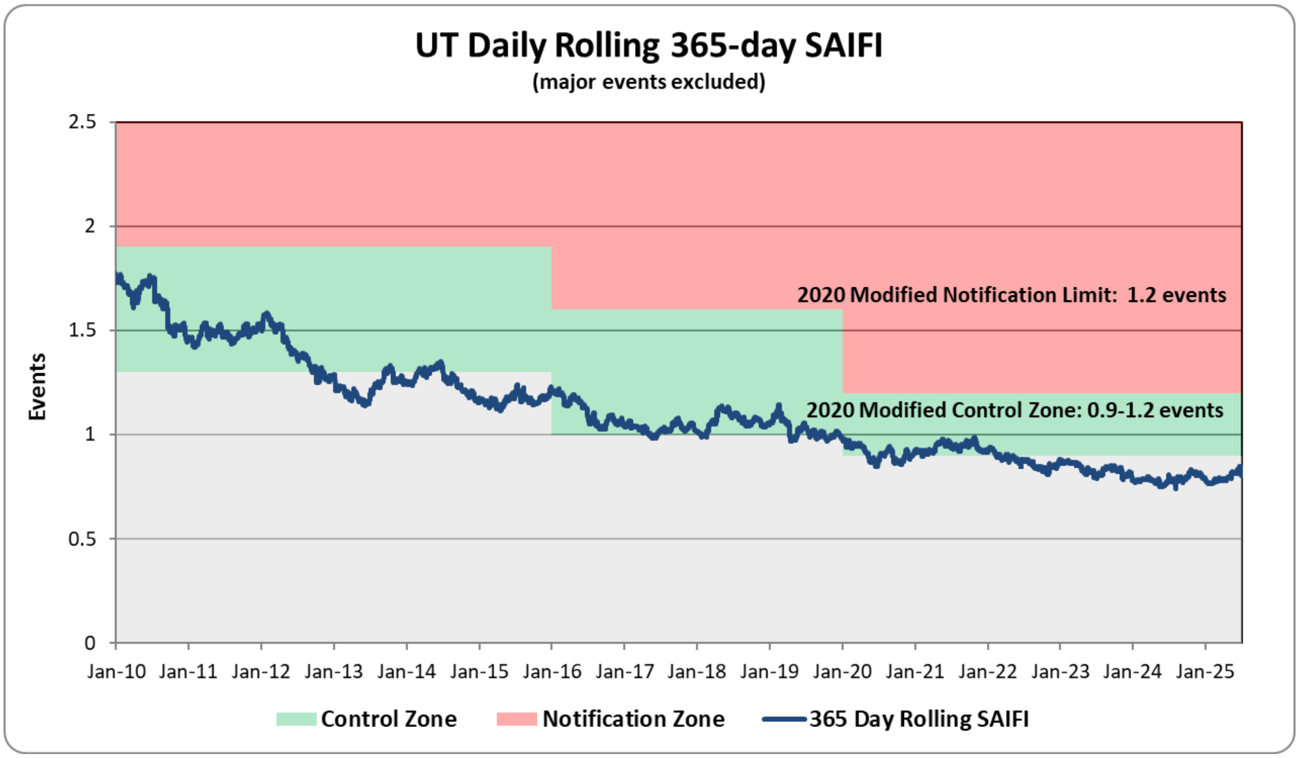

365-Day Rolling Underlying History As Reported
SAIDI (Minutes)
SAIFI (Events)
0
20
40
60
80
100
120
140
160
180
200
220
240
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Jan-2019
Jan-2020
Jan-2021
Jan-2022
Jan-2023
Jan-2024
Jan-2025
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

## 2.3 Baseline Performance

In compliance with Utah Reliability Reporting Rules, the Company developed performance baselines that subsequently filed for approval (based on 2008-2012 history). The baseline values were calculated using the 12-month moving average data for SAIDI and SAIFI over a 5-year period as the mean, plus or minus approximately two standard deviations. These baselines were approved, but stakeholders advocated that periodically refreshing baseline levels would be beneficial. As a result, on December 20, 2016, the Public Service Commission of Utah approved modified electric service reliability performance baseline notification levels (Docket No. 13-035-01 and 15-035-72). On June 23, 2020, the Commission directed the Company to work with parties to review the baselines. The original and modified baselines are shown below.

| | SAIDI (Minutes) | | SAIFI (Events) | |
|---|---|---|---|---|
| | Lower Value Control Zone | Upper Value Control Zone | Lower Value Control Zone | Upper Value Control Zone |
| **Prior Baseline** | 151 | 201 | 1.3 | 1.9 |
| **2016 Modified Baseline** | 137 | 187 | 1.0 | 1.6 |
| **2020 Modified Baseline** | 107 | 157 | 0.9 | 1.2 |




UT Daily Rolling 365-day SAIFI
(major events excluded)
Events
2.5
2
1.5
1
0.5
0
2020 Modified Notification Limit: 1.2 events
2020 Modified Control Zone: 0.9-1.2 events
Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19 Jan-20 Jan-21 Jan-22 Jan-23 Jan-24 Jan-25
Control Zone
Notification Zone
365 Day Rolling SAIFI

## 2.4 Reliability Reporting Post-Rule R.746-313 Modifications

In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Administrative Code R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Specific elements may be at least partially redundant or segmented differently than has been provided in the past.

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 $MAIFI_E$[12] are required.

| Major Events, ESS, and Prearranged Excluded* | 2021 | | | | 2022 | | | | 2023 | | | | 2024 | | | | 2025-June | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STATE | SAIDI | SAIFI | CAIDI | MAIFIe | SAIDI | SAIFI | CAIDI | MAIFIe | SAIDI | SAIFI | CAIDI | MAIFIe | SAIDI | SAIFI | CAIDI | MAIFIe | SAIDI | SAIFI | CAIDI | MAIFIe |
| Utah | 108 | 0.9 | 119 | 1.89 | 102 | 0.9 | 118 | 0.42 | 98 | 0.8 | 125 | 0.41 | 93 | 0.8 | 118 | 0.70 | 44 | 0.4 | 120 | 0.27 |
| OP AREA | | | | | | | | | | | | | | | | | | | | |
| AMERICAN FORK | 56 | 0.4 | 144 | | 75 | 0.6 | 124 | | 117 | 1.1 | 104 | | 52 | 0.6 | 84 | | 26 | 0.2 | 118 | |
| CEDAR CITY | 144 | 1.3 | 111 | | 107 | 1.0 | 108 | | 95 | 0.9 | 109 | | 82 | 0.8 | 105 | | 41 | 0.3 | 157 | |
| CEDAR CITY (MILFORD) | 270 | 2.0 | 133 | | 173 | 0.9 | 194 | | 302 | 1.9 | 159 | | 519 | 2.1 | 246 | | 48 | 0.3 | 161 | |
| EVANSTON | 26 | 0.2 | 112 | | 21 | 0.2 | 128 | | 52 | 0.2 | 308 | | 42 | 0.5 | 82 | | 2 | 0 | 233 | |
| JORDAN VALLEY | 109 | 1.0 | 114 | | 72 | 0.7 | 102 | | 54 | 0.5 | 114 | | 69 | 0.6 | 123 | | 39 | 0.3 | 122 | |
| LAYTON | 119 | 1.2 | 96 | | 69 | 0.6 | 112 | | 66 | 0.6 | 103 | | 71 | 0.7 | 109 | | 30 | 0.3 | 116 | |
| MOAB | 146 | 1.2 | 126 | | 125 | 1.2 | 103 | | 231 | 1.8 | 130 | | 197 | 1.2 | 158 | | 17 | 0.3 | 64 | |
| MONTPELIER | 78 | 1.1 | 73 | | 216 | 0.9 | 235 | | 15 | 0.1 | 99 | | 232 | 3.2 | 73 | | 60 | 0.3 | 214 | |
| OGDEN | 126 | 1.0 | 127 | | 119 | 0.8 | 141 | | 136 | 0.8 | 179 | | 145 | 0.9 | 157 | | 66 | 0.4 | 162 | |
| PARK CITY | 121 | 0.7 | 166 | | 171 | 0.9 | 186 | | 219 | 1.3 | 169 | | 137 | 0.8 | 170 | | 44 | 0.4 | 101 | |
| PRICE | 64 | 1.0 | 63 | | 143 | 1.5 | 94 | | 76 | 0.7 | 105 | | 158 | 1.3 | 124 | | 82 | 0.4 | 202 | |
| RICHFIELD | 213 | 1.2 | 175 | | 220 | 1.7 | 133 | | 50 | 0.4 | 123 | | 73 | 0.9 | 79 | | 29 | 0.4 | 68 | |
| RICHFIELD (DELTA) | 340 | 2.7 | 128 | | 138 | 2.0 | 70 | | 89 | 0.7 | 125 | | 112 | 0.8 | 134 | | 37 | 0.1 | 442 | |
| SLC METRO | 226 | 1.9 | 120 | | 103 | 1.0 | 108 | | 89 | 0.7 | 123 | | 104 | 0.9 | 118 | | 57 | 0.5 | 106 | |
| SMITHFIELD | 80 | 0.9 | 86 | | 94 | 0.8 | 116 | | 174 | 1.7 | 101 | | 104 | 1.1 | 94 | | 7 | 0.1 | 52 | |
| TOOELE | 155 | 1.4 | 112 | | 184 | 1.8 | 103 | | 96 | 0.8 | 116 | | 94 | 1.2 | 78 | | 45 | 0.4 | 108 | |
| TREMONTON | 92 | 0.8 | 117 | | 213 | 1.9 | 115 | | 240 | 1.5 | 158 | | 152 | 2.0 | 75 | | 102 | 0.7 | 143 | |
| VERNAL | 64 | 0.4 | 165 | | 86 | 0.7 | 127 | | 49 | 0.3 | 182 | | 35 | 0.3 | 105 | | 17 | 0.4 | 45 | |

* except MAIFIe

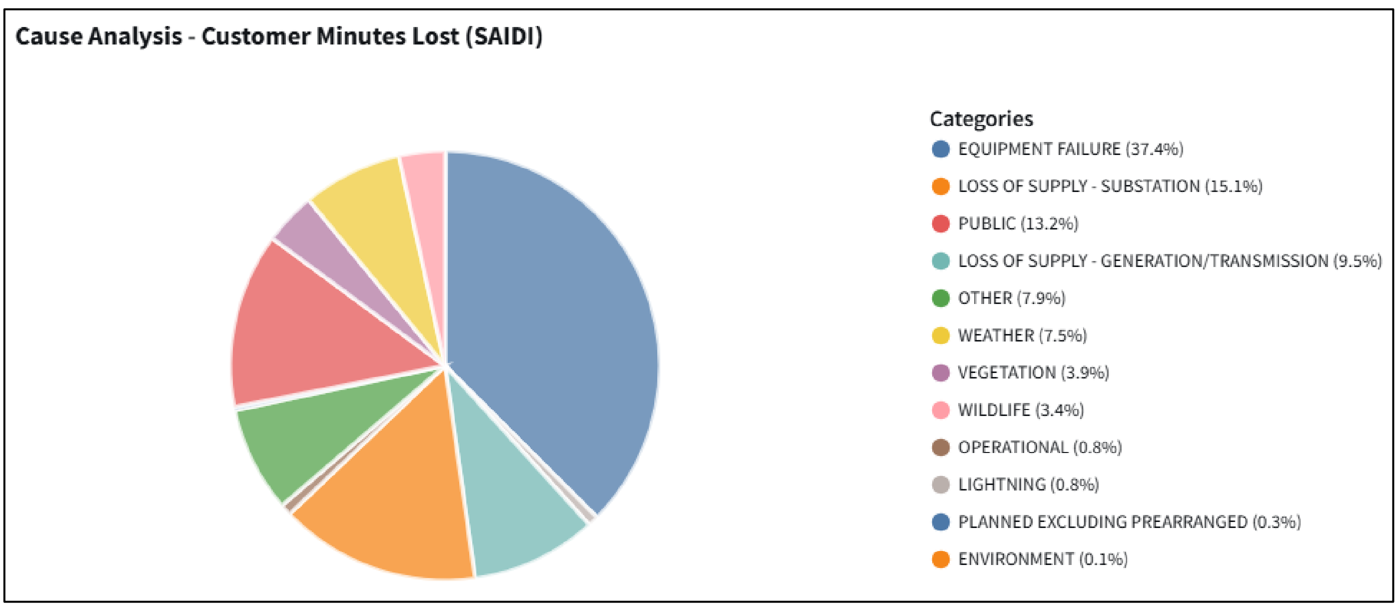
[12] Reported $MAIFI_E$ is calculated using only momentary distribution outage records from the system of record.

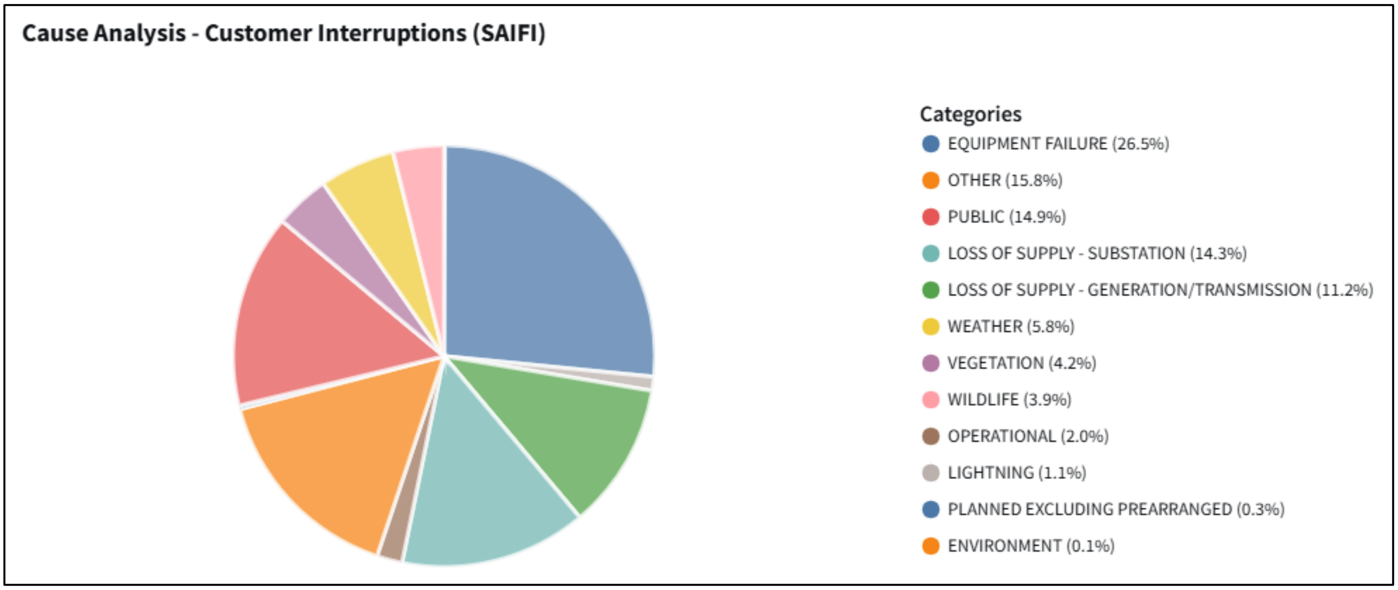
# 2.5 Cause Analyses – Underlying and ESS

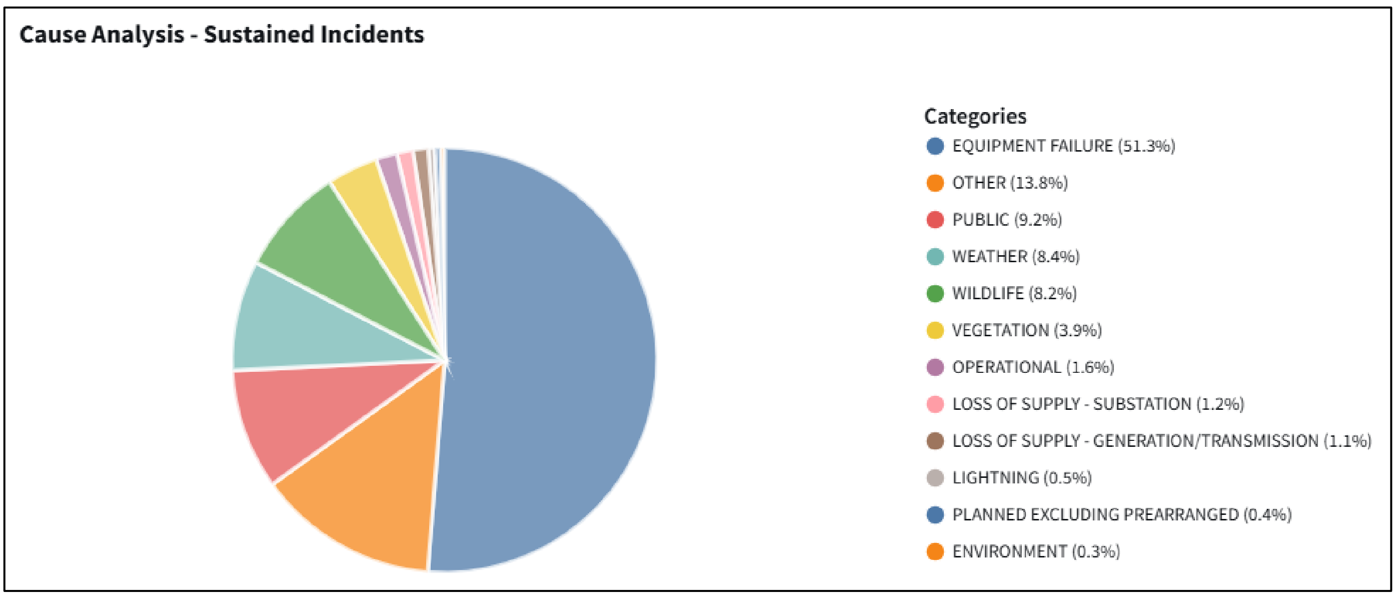
Section 2.5.1 provides an analysis of outage causes for Underlying outages, while Section 2.5.2 shows the outages related to Enhanced Safety Settings (ESS).

## 2.5.1 Underlying Cause Analyses Charts

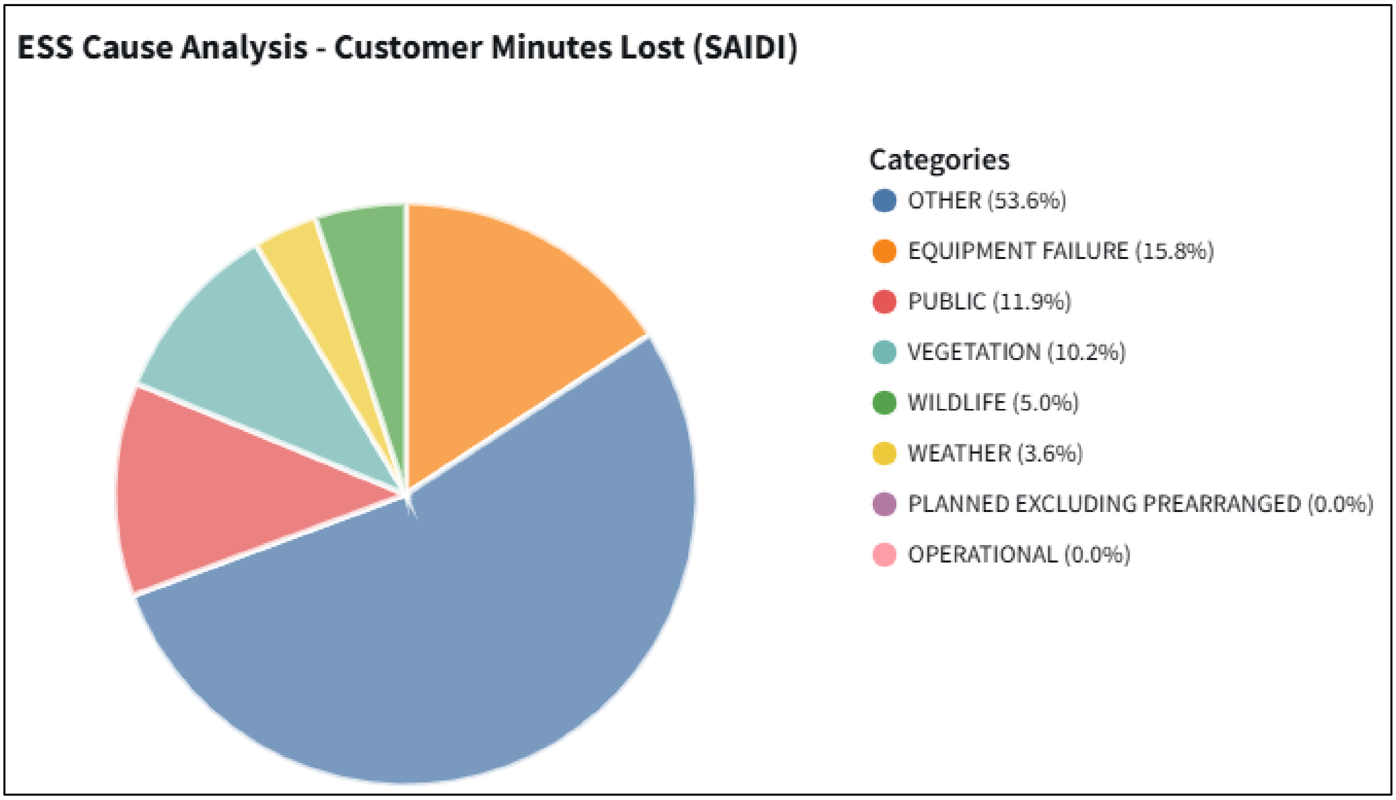
| Utah Cause Category | 2021 | | 2022 | | 2023 | | 2024 | | 2025-June | |
|---|---|---|---|---|---|---|---|---|---|---|
| | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI |
| Environment | 1 | 0.00 | 0 | 0.00 | 1 | 0.00 | 1 | 0.00 | 0 | 0.00 |
| Equipment Failure | 42 | 0.40 | 38 | 0.24 | 36 | 0.21 | 35 | 0.19 | 17 | 0.10 |
| Lightning | 3 | 0.00 | 2 | 0.02 | 3 | 0.03 | 2 | 0.02 | 0 | 0.00 |
| Loss of Supply - Generation/Transmission | 9 | 0.10 | 10 | 0.12 | 15 | 0.17 | 8 | 0.12 | 4 | 0.04 |
| Loss of Supply - Substation | 10 | 0.10 | 15 | 0.15 | 6 | 0.05 | 11 | 0.13 | 7 | 0.05 |
| Operational | 1 | 0.00 | 0 | 0.00 | 1 | 0.02 | 0 | 0.01 | 0 | 0.01 |
| Other | 2 | 0.00 | 2 | 0.02 | 1 | 0.02 | 9 | 0.11 | 4 | 0.06 |
| Planned (excl. Prearranged) | 3 | 0.00 | 2 | 0.02 | 0 | 0.01 | 0 | 0.01 | 0 | 0.00 |
| Public | 13 | 0.10 | 11 | 0.10 | 15 | 0.11 | 13 | 0.10 | 6 | 0.06 |
| Unknown | 5 | 0.10 | 5 | 0.06 | 4 | 0.05 | 0 | 0.00 | 0 | 0.00 |
| Vegetation | 6 | 0.00 | 6 | 0.04 | 5 | 0.04 | 4 | 0.02 | 2 | 0.02 |
| Weather | 10 | 0.10 | 11 | 0.07 | 8 | 0.06 | 8 | 0.05 | 3 | 0.02 |
| Wildlife | 3 | 0.00 | 2 | 0.02 | 2 | 0.03 | 3 | 0.03 | 2 | 0.01 |
| UTAH Underlying | 108 | 0.90 | 102 | 0.87 | 98 | 0.78 | 93 | 0.79 | 44 | 0.37 |



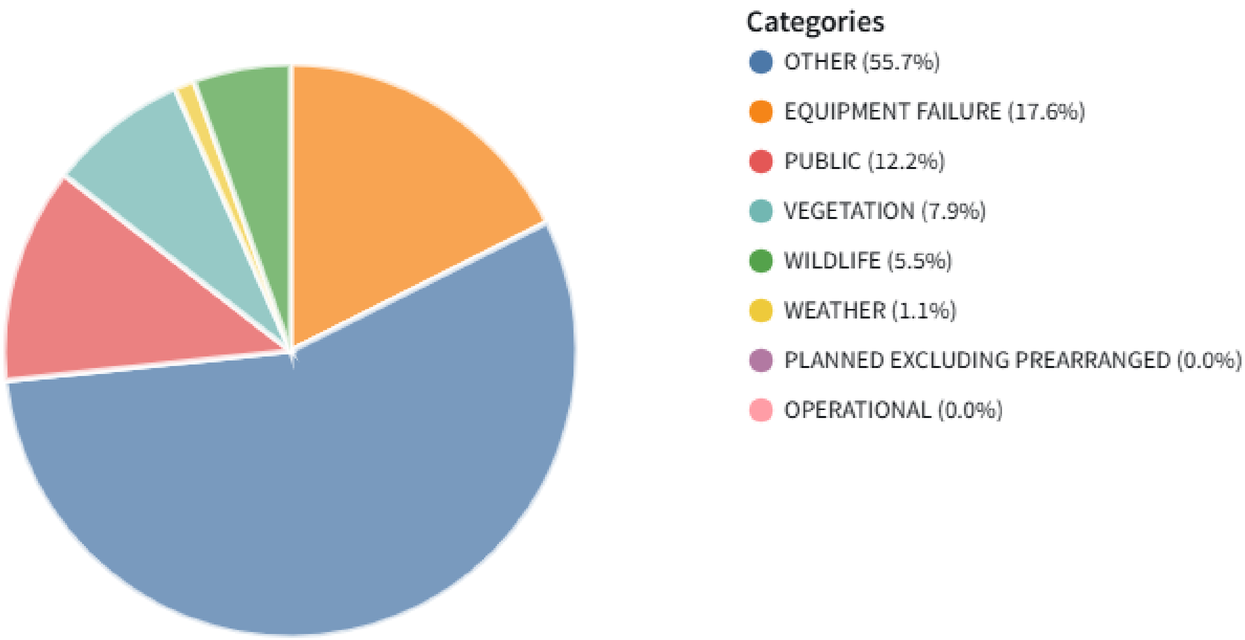

Cause Analysis - Customer Interruptions (SAIFI)
Categories
EQUIPMENT FAILURE (26.5%)
OTHER (15.8%)
PUBLIC (14.9%)
LOSS OF SUPPLY - SUBSTATION (14.3%)
LOSS OF SUPPLY - GENERATION/TRANSMISSION (11.2%)
WEATHER (5.8%)
VEGETATION (4.2%)
WILDLIFE (3.9%)
OPERATIONAL (2.0%)
LIGHTNING (1.1%)
PLANNED EXCLUDING PREARRANGED (0.3%)
ENVIRONMENT (0.1%)


Cause Analysis - Sustained Incidents
Categories
EQUIPMENT FAILURE (51.3%)
OTHER (13.8%)
PUBLIC (9.2%)
WEATHER (8.4%)
WILDLIFE (8.2%)
VEGETATION (3.9%)
OPERATIONAL (1.6%)
LOSS OF SUPPLY - SUBSTATION (1.2%)
LOSS OF SUPPLY - GENERATION/TRANSMISSION (1.1%)
LIGHTNING (0.5%)
PLANNED EXCLUDING PREARRANGED (0.4%)
ENVIRONMENT (0.3%)

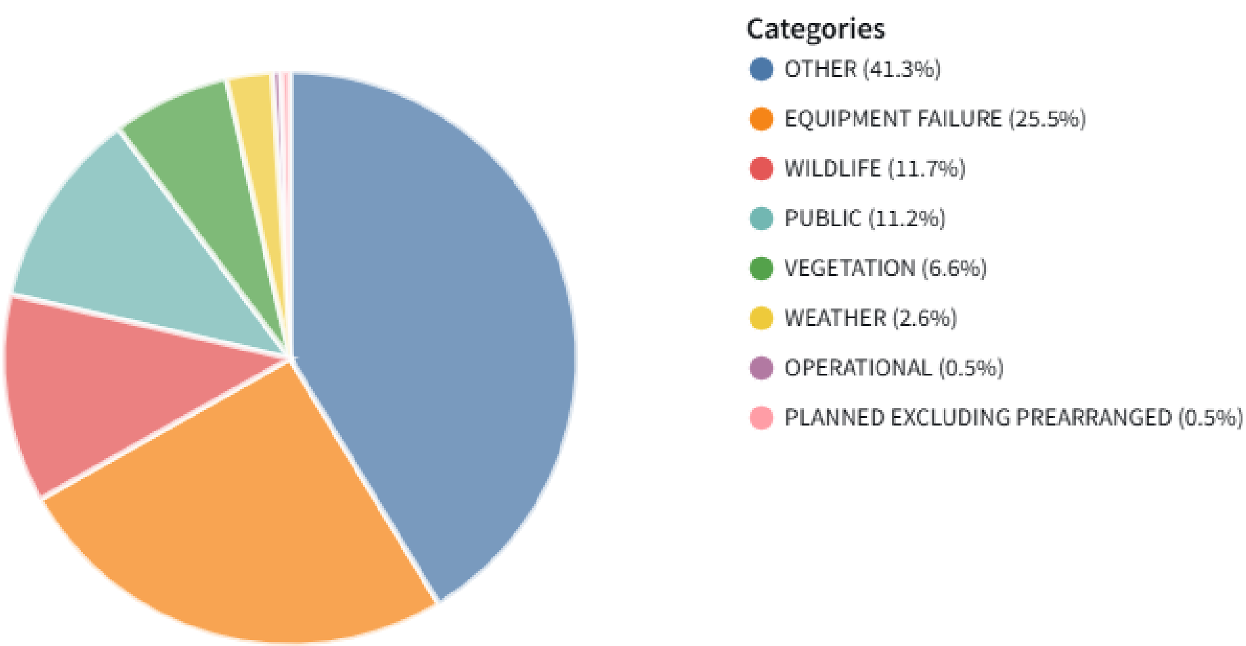
## 2.5.2 Enhanced Safety Settings (ESS) Cause Analyses Charts



## ESS Cause Analysis - Customer Interruptions (SAIFI)




## ESS Cause Analysis - Sustained Incidents



# 3 Improve Reliability Performance in Areas of Concern

Rocky Mountain Power is committed to delivering safe and reliable power. For years, the Company has developed, monitored, and tracked reliability metrics in accordance with industry standards and regulatory requirements. Over time, improvements have been made to minimize the impact of power interruptions by reducing outage duration and frequency. To continue keeping its commitment to deliver safe and reliable power, Rocky Mountain Power develops a reliability plan annually to identify new projects and programs to continually improve system performance and resilience.

Rocky Mountain Power’s reliability plan is a key program that is used to improve system reliability. The development of individual reliability work plans is a strategic approach based upon current trends in performance through multiple metrics. Care is taken to ensure that project selection does not limit funding in areas of low customer density over more densely populated areas.

Rocky Mountain Power implemented annual safety inspections starting in 2025, along with increased frequency for detailed overhead and underground inspections from 20-year to 10-year cycles starting in 2024. Increasing the frequency of these inspections is anticipated to reduce equipment failure outages.

An area of concern that has been identified is circuits that serve many customers. As a result, Rocky Mountain Power implemented a mainline sectionalizing guideline to reduce the number of customers exposed per feeder. The guide outlines recommendations for a maximum of 2,250 customers per feeder, which are to be further subdivided into protection zones of no more than 750 customers. The system is reviewed annually to determine which circuits should be prioritized based on greatest amount of risk to reliability and projects are implemented based on available funding.

# 4 Customer Response

## 4.1 Telephone Service and Response to Commission Complaints

| COMMITMENT | GOAL | PERFORMANCE |
|---|---|---|
| PS5-Answer calls within 30 seconds | 80% | 74% |
| PS6a) Respond to commission complaints within 3 days | 95% | 97% |
| PS6b) Respond to commission complaints regarding service disconnects within 4 hours | 95% | 100% |
| PS6c) Address commission[13] complaints within 30 days | 100% | 99% |

Rocky Mountain Power remains committed to delivering exceptional customer experience, though PS5 service level performance fell short of established goals in 2025. The Company achieved a mid-year service level of 74%, reflecting the impacts of higher call volumes, which have increased by approximately 20,000 calls year-to-date compared to the previous year, over the same period.

Despite these challenges, the Company maintained a strong focus on customer experience and operational performance. The continued use of the customer callback program, implemented at the end of 2024, has provided customers with the option to receive a return call rather than waiting on hold during peak periods.

Rocky Mountain Power has developed a comprehensive training and staffing plan to enhance workforce readiness and strengthen service level performance moving forward. These efforts are expected to provide necessary support to move the Company closer to achieving its service level goals while maintaining its commitment to timely, high-quality customer service.

## 4.2 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, 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 mid-year 2025, there were four days identified as wide-scale outage days. Event details and call statistics are shown in the bullets and table below.

- On February 3, 2025, Southern Oregon and the Portland metro experienced a winter storm event causing widespread distribution outages across Klamath Falls, Lakeview, Grants Pass, Medford, Yreka, and Portland. The event affected approximately 12,039 customers.
- On April 1, 2025, Central Oregon experienced a transmission outage due to a loss of supply during Portland General Electric maintenance at Round Butte substation that triggered a breaker alarm failure,

[13] 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).

cutting source to multiple substations in the Madras, Culver, Crooked River, and Warm Springs area. The event affected 11,103 customers and service was restored in about 57 minutes.

- On June 9, 2025, Portland, Oregon experienced a transmission event when circuit breakers 2P57 and 2P103 at St. Johns and Knott substations locked open, resulting in loss of transmission to several feeders. The event affected up to 41,748 customers, with full restoration by 11:37.
- On June 24, 2025, Portland, Oregon experienced a circuit outage at Columbia substation on circuit 5P478 when the SCADA-controlled breaker stood open before reclosing. The event affected 888 customers.

| Date | Interval Start/Finish (MT Time) | | Network Total Calls | Calls Received but Not Delivered | # of Calls Abandoned from Agent Queue | Max Delay Time Seconds | ASA Seconds |
|---|---|---|---|---|---|---|---|
| 2/3/2025 | 15:30 | 15:45 | 501 | 0 | 90 | 2374 | 106 |
| | 15:45 | 16:00 | 428 | 0 | 80 | 2561 | 74 |
| | 16:00 | 16:15 | 492 | 0 | 159 | 2652 | 97 |
| | 16:15 | 16:30 | 606 | 0 | 127 | 2200 | 120 |
| | 16:30 | 16:45 | 529 | 0 | 60 | 1572 | 117 |
| | 16:45 | 17:00 | 424 | 0 | 60 | 1829 | 84 |
| 4/1/2025 | 11:30 | 11:45 | 389 | 0 | 21 | 651 | 52 |
| | 11:45 | 12:00 | 395 | 0 | 33 | 844 | 26 |
| | 12:00 | 12:15 | 713 | 189 | 104 | 788 | 21 |
| | 12:15 | 12:30 | 992 | 276 | 32 | 628 | 18 |
| | 12:30 | 12:45 | 479 | 1 | 27 | 719 | 11 |
| | 12:45 | 13:00 | 394 | 0 | 26 | 481 | 15 |
| | 13:00 | 13:15 | 383 | 0 | 41 | 560 | 10 |
| 6/9/2025 | 11:30 | 11:45 | 356 | 0 | 32 | 647 | 17 |
| | 11:45 | 12:00 | 328 | 0 | 20 | 948 | 21 |
| | 12:00 | 12:15 | 332 | 0 | 24 | 1032 | 16 |
| | 12:15 | 12:30 | 1,931 | 1,255 | 208 | 814 | 288 |
| | 12:30 | 12:45 | 1,095 | 496 | 153 | 464 | 176 |
| | 12:45 | 13:00 | 375 | 0 | 29 | 1011 | 33 |
| | 13:00 | 13:15 | 306 | 0 | 41 | 1296 | 27 |
| | 13:15 | 13:30 | 336 | 0 | 38 | 1034 | 21 |
| 6/24/2025 | 16:30 | 16:45 | 991 | 192 | 38 | 420 | 22 |
| | 16:45 | 17:00 | 434 | 0 | 22 | 1075 | 20 |
| | 17:00 | 17:15 | 328 | 0 | 20 | 1511 | 18 |
| | 17:15 | 17:30 | 263 | 0 | 27 | 1396 | 8 |

## 4.3 Utah State Customer Guarantee Summary Status[14]

customer*guarantees* January to June 2025

**Utah**

| | Description | 2025 Events | 2025 Failures | 2025 % Success | 2025 Paid | 2024 Events | 2024 Failures | 2024 % Success | 2024 Paid |
|---|---|---|---|---|---|---|---|---|---|
| CG1 | Restoring Supply | 521,208 | 18 | 100.00% | $900 | 559,261 | 0 | 100.00% | $0 |
| CG2 | Appointments | 4,149 | 5 | 99.88% | $250 | 3,768 | 2 | 99.95% | $100 |
| CG3 | Switching on Power | 9,407 | 1 | 99.99% | $50 | 6,977 | 0 | 100.00% | $0 |
| CG4 | Estimates | 703 | 1 | 99.86% | $50 | 687 | 0 | 100.00% | $0 |
| CG5 | Respond to Billing Inquiries | 791 | 4 | 99.49% | $200 | 763 | 2 | 99.74% | $100 |
| CG6 | Respond to Meter Problems | 339 | 0 | 100.00% | $0 | 285 | 0 | 100.00% | $0 |
| CG7 | Notification of Planned Interruptions | 114,205 | 26 | 99.98% | $1,300 | 107,877 | 10 | 99.99% | $500 |
| | | **650,802** | **55** | **99.99%** | **$2,750** | **679,618** | **14** | **99.99%** | **$700** |

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.

[14] Customer satisfaction guarantees were issued in docket number 05-035-54 Merger Commitment U9 and Commission Order on Service Quality Reporting issued February 27, 2014.

# 5 Maintenance Compliance to Annual Plan

## 5.1 T&D Preventive and Corrective Maintenance Programs

**Preventive Maintenance**

The primary focus of the preventive maintenance (PM) plan is to inspect facilities, identify abnormal conditions[15], and take necessary corrective actions. As the Company reviews its policies, factoring in both costs and benefits, modifications will be made where appropriate. Local triggers that result in more frequent or more burdensome inspection and maintenance practices have refined some of these PM activities. As the Company continues its assessment, additional policy changes will continue to refine the maintenance plan.

***Transmission and Distribution Lines***

- Visual assurance inspections are conducted to identify damage or defects that may endanger public safety or compromise the integrity of the electrical system.
- Detailed inspections involve an in-depth visual examination of each structure and the spans between them, as well as pad-mounted distribution equipment.[16]
- Pole testing involves sounding and boring to reveal decay pockets that may compromise the structural integrity of wood poles.

***Substations and Major Equipment***

- Rocky Mountain Power conducts inspections and maintenance of substations and their equipment to verify proper operation. Any abnormal conditions are identified and prioritized for corrective maintenance.
- The Company follows a condition-based maintenance program for substation equipment, including load tap changers, regulators, and transmission circuit breakers. Routine diagnostic tests help determine if the equipment is in good condition or needs servicing. Protection and communication systems undergo maintenance on a time-based schedule.

**Corrective Maintenance**

The primary objective of the corrective maintenance plan is to address abnormal conditions identified during the preventative maintenance process.

---

[15] 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.

[16] 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.

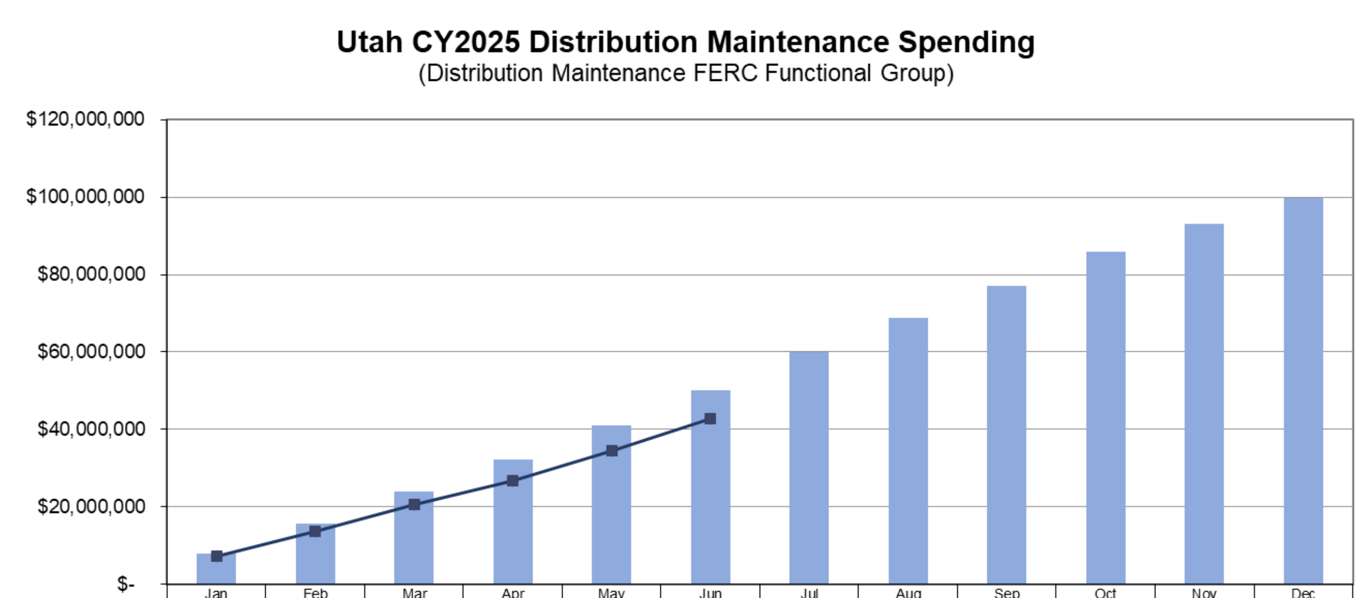
***Transmission and Distribution Lines***

- Abnormal conditions are detected through preventive maintenance inspections.
- Outstanding conditions are recorded in a database and remain logged until they are corrected.

***Substations and Major Equipment***

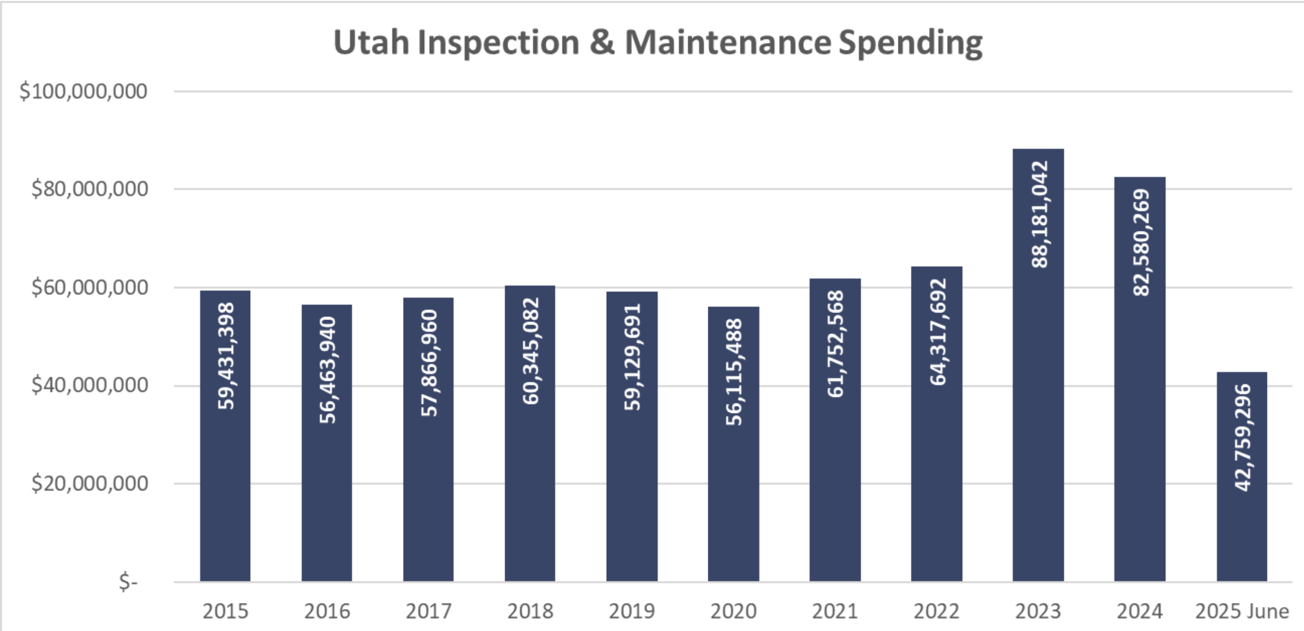
- Correctable conditions, often related to major equipment, are flagged during preventative maintenance activities.
- Corrections typically involve repairing equipment or addressing failed components.

## 5.2 Maintenance Spending



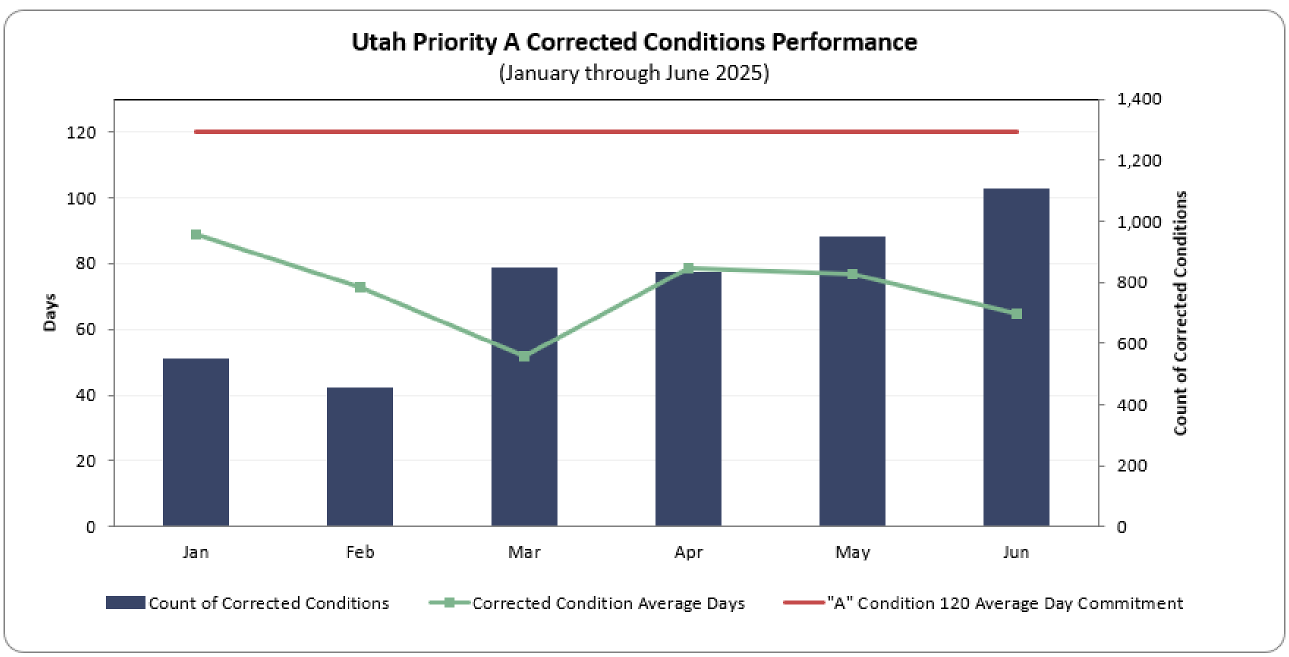

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plan | $7,978,343 | $15,594,008 | $23,906,812 | $32,087,627 | $41,084,324 | $50,156,723 | $59,890,981 | $68,747,293 | $77,201,111 | $86,004,518 | $92,993,284 | $99,843,050 |
| Actual | $7,193,154 | $13,730,850 | $20,603,568 | $26,688,873 | $34,588,915 | $42,759,296 | | | | | | |

### 5.2.1 Maintenance Historical Spending




## 5.3 Distribution Priority "A" Conditions Correction History

Rocky Mountain Power is committed to correcting Priority "A" Conditions with an average age of 120 days or less. The Company believes that it is a useful indicator of its commitment to providing safe and reliable service to its Utah customers.

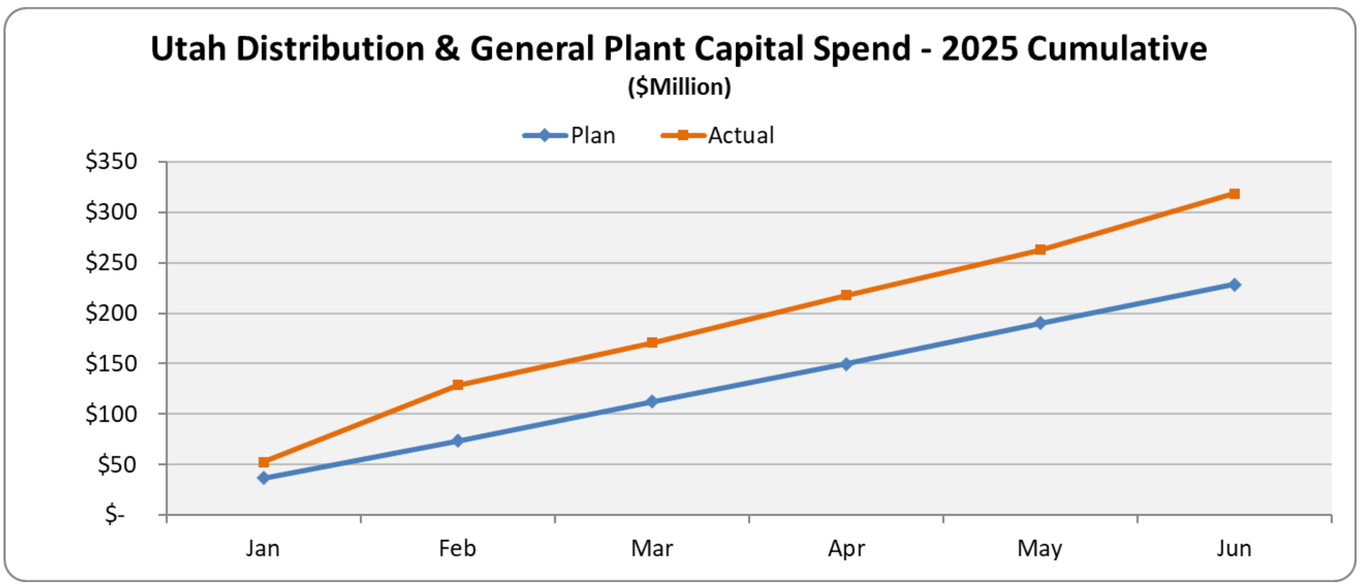


# 6 Capital Investment

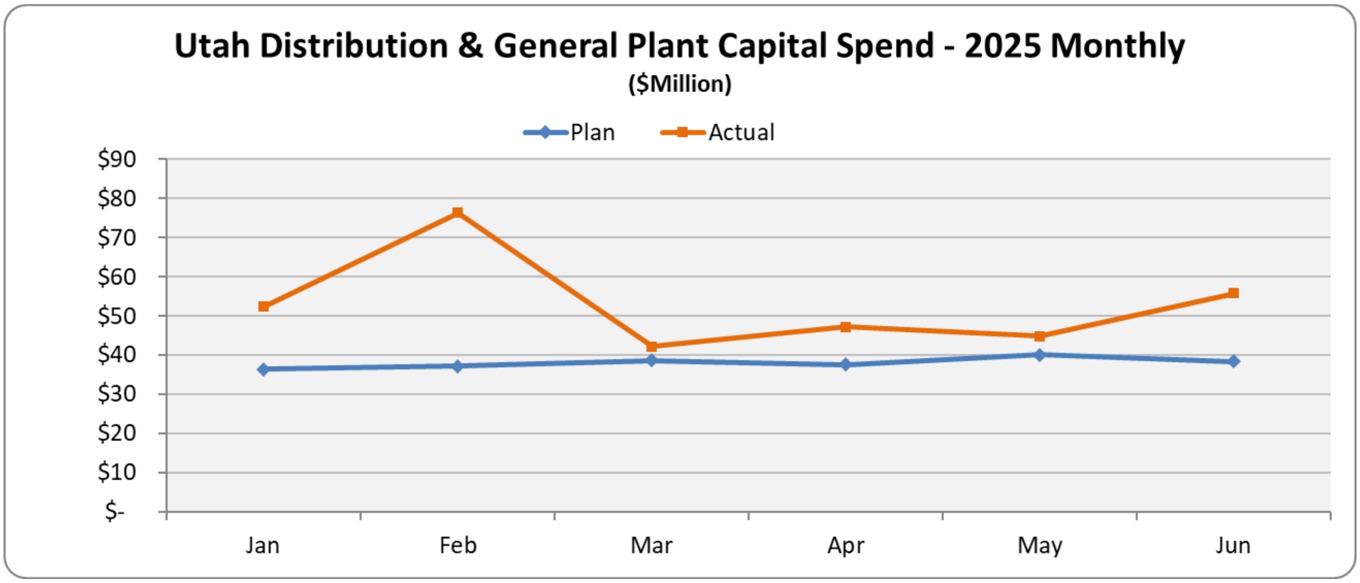
## 6.1 Capital Spending – Distribution and General Plant[17]

### January – June 2025

| Investment | Actual ($m) | Plan ($m) | Significant Variances |
|---|---|---|---|
| 1. Mandated | $102.8 | $38.9 | Mandated distribution wildfire mitigation over plan (+$62.5m) due to wildfire projects acceleration and greater amount of distribution wildfire project work. |
| 2. New Connect | $84.5 | $95.9 | Commercial new revenue connections under plan (–$10.3m). |
| 3. System Reinforcement | $45.0 | $43.8 | No significant variances. |
| 4. Replacement | $54.1 | $46.2 | Overhead pole replacements over plan (+$9.7m) primarily due to increased B-condition project work and increased labor and material prices. |
| 5. Upgrade & Modernize | $32.2 | $3.5 | Terminal T&D Operations Campus over plan (+$26.3m) due to project timing. |
| **Total** | **$318.5** | **$228.3** | |




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

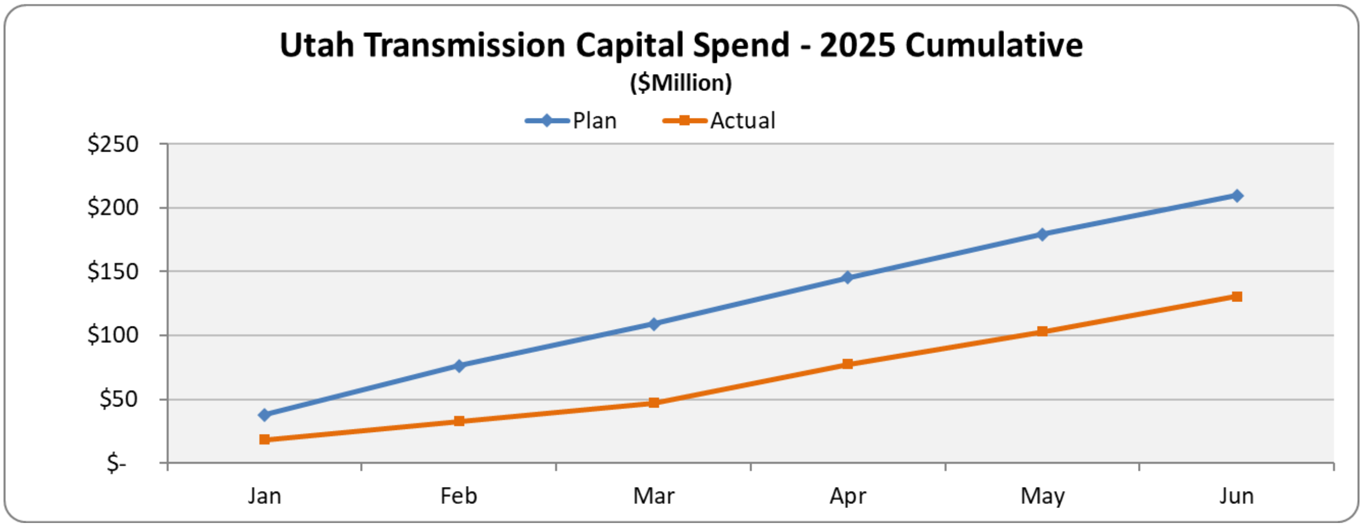


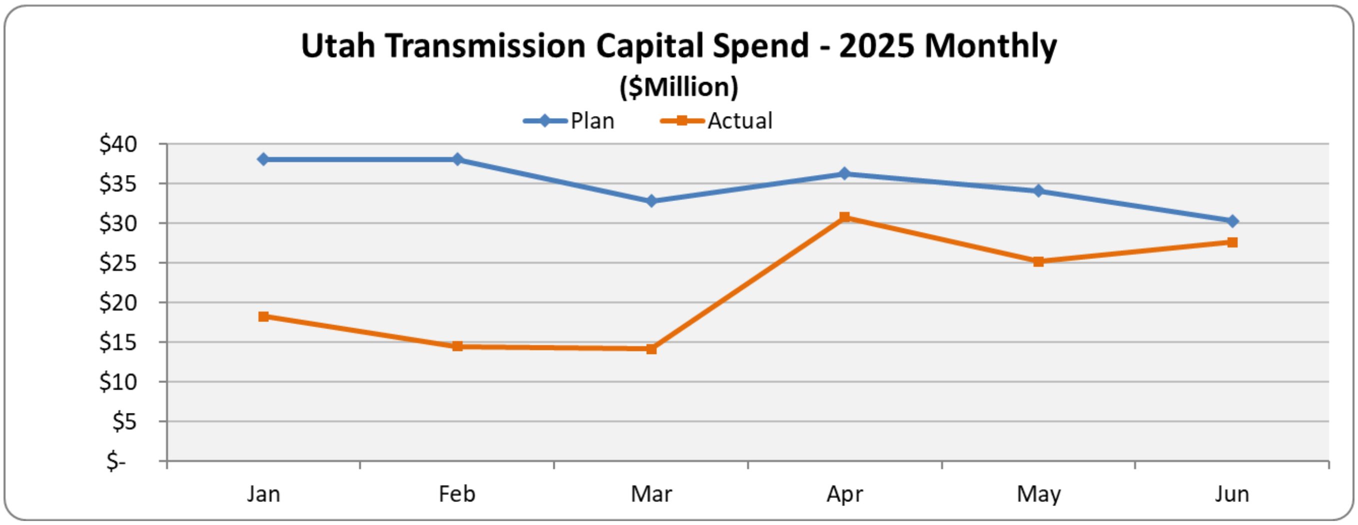

## 6.2 Capital Spending – Transmission/Interconnections[18]

### January – June 2025

| | Investment | Actual ($m) | Plan ($m) | Significant Variances |
|---|---|---|---|---|
| 1. | Mandated | $27.0 | $25.0 | No significant variances. |
| 2. | New Connect | $13.0 | $11.7 | No significant variances. |
| 3. | Local Transmission System Reinforcements | $9.2 | $(1.6) | A plan adjustment (–$5.5m for Jan-Jun 2025) was included to account for unknown project delays expected to occur throughout the year due to companywide reprioritization of capital. |
| 4. | Main Grid Reinforcements / Interconnections[19] | $33.3 | $92.5[20] | St. George Sub 345-138kV transformer Yard under plan (–$7.1m) due to transformer order delay which pushed out progress payments. Spanish Fork-Mercer 345kV Line under plan (–$10.4m) due to delay of easement costs into 2026. Camp Williams 345-138kV transformer-138kV Yard under plan (–$11.7m) due to transformer delivery being accelerated into 2024. Unidentified main grid/generation interconnections under plan (–$26.0m — see explanation below). |
| 5. | Energy Gateway Transmission[19] | $21.0 | $17.3 | Oquirrh Terminal 345kV Line over plan (+$6.4m) due to mitigation resolution costs higher than estimated. Transmission line was placed in service in 2024. |
| 6. | Transmission Expansion[19] | $10.3 | $42.2 | Gateway Central Limber Area under plan (–$15.0m) and Gateway Central Reinforcements Seg B under plan (–$13.5m) due to companywide reprioritization of capital. |
| 7. | Replacement | $15.8 | $18.9 | No significant variances. |
| 8. | Upgrade & Modernize | $0.8 | $3.7 | No significant variances. |
| | **Total** | **$130.4** | **$209.6** | |

[18] Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.
[19] Main Grid Reinforcements/Interconnections, Transmission Expansion and Energy Gateway Transmission values include a small amount of general plant/communications and distribution work.
[20] Unidentified main grid/generation interconnection projects are managed at the program level. Plan funding is 100% allocated to Utah, by necessity, for Plan application purposes only. Actual funding is reallocated to specific projects across PacifiCorp as identified or as customer agreements are signed, not necessarily within the state of Utah.


Utah Transmission Capital Spend - 2025 Cumulative
($Million)
Plan
Actual
$250
$200
$150
$100
$50
$-
Jan
Feb
Mar
Apr
May
Jun


Utah Transmission Capital Spend - 2025 Monthly
($Million)
Plan
Actual
$40
$35
$30
$25
$20
$15
$10
$5
$-
Jan
Feb
Mar
Apr
May
Jun

# 6.3 New Connects[21]

| | 2024 | 2025 | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **YEAR** | Jan | Feb | Mar | Apr | May | Jun | **YEAR** |
| ***Residential*** | | | | | | | | |
| UT South | 2,492 | 176 | 149 | 190 | 268 | 175 | 355 | 1,313 |
| UT North/Metro | 11,235 | 551 | 764 | 473 | 881 | 762 | 614 | 4,045 |
| UT Central | 13,066 | 1,103 | 1,088 | 855 | 996 | 1,076 | 930 | 6,048 |
| **Total Residential** | **26,793** | **1,830** | **2,001** | **1,518** | **2,145** | **2,013** | **1,899** | **11,406** |
| ***Commercial*** | | | | | | | | |
| UT South | 459 | 44 | 45 | 57 | 43 | 32 | 57 | 278 |
| UT North/Metro | 1,567 | 99 | 83 | 104 | 108 | 114 | 135 | 643 |
| UT Central | 2,583 | 243 | 188 | 163 | 197 | 160 | 147 | 1,098 |
| **Total Commercial** | **4,609** | **386** | **316** | **324** | **348** | **306** | **339** | **2,019** |
| ***Industrial*** | | | | | | | | |
| UT South | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| UT North/Metro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| UT Central | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Industrial** | **1** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| ***Irrigation*** | | | | | | | | |
| UT South | 34 | 2 | 2 | 2 | 4 | 5 | 5 | 20 |
| UT North/Metro | 3 | 0 | 1 | 0 | 1 | 0 | 1 | 3 |
| UT Central | 17 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| **Total Irrigation** | **54** | **2** | **3** | **2** | **5** | **5** | **7** | **24** |
| ***TOTAL New Connects*** | | | | | | | | |
| UT South | 2,986 | 222 | 196 | 249 | 315 | 212 | 417 | 1,611 |
| UT North/Metro | 12,805 | 650 | 848 | 577 | 990 | 876 | 750 | 4,691 |
| UT Central | 15,666 | 1,346 | 1,276 | 1,018 | 1,193 | 1,236 | 1,078 | 7,147 |
| **TOTAL New Connects** | **31,457** | **2,218** | **2,320** | **1,844** | **2,498** | **2,324** | **2,245** | **13,449** |

Notes:

- The Utah South region includes the operating areas of Cedar City, Moab, Price and Richfield.
- The Utah North/Metro region includes the operating areas of Layton, Ogden and SLC Metro.
- The Utah Central region includes the operating areas of American Fork, Jordan Valley, Park City, Tooele and Vernal.
- Regional areas are subject to change for operational purposes and may differ from historical reporting.

[21] In 2021, after adopting a new data processing tool, several process improvements were made. Temporary connections, which were previously excluded, are now included, allowing for earlier reporting of actual installation dates. There is no double counting of new connections, as the temporary connection is replaced when a permanent one is established, while retaining the original installation date.

In 2015, the Company's regulation department mandated that all temporary connections be coded as commercial to apply commercial billing rates to contractors using electricity until a homeowner takes occupancy. Given that residential customers vastly outnumber commercial ones, this skewed the reported volumes, leading to the exclusion of temporary connections.

Now, temporary connections are included without distorting commercial volume reporting. Commercially classed temporary connections are reclassified as residential when associated with residential dwelling codes. This new process is based on actual installation data rather than customer contract data and is expected to eliminate distortions in historical volume records caused by customer changes.

# 7 Vegetation Management

## 7.1 Production

**UTAH**

**Tree Program Reporting**

**January 1, 2025 through June 30, 2025**
**Distribution**

| | Total | Calendar Year Reporting | | | | Cycle Reporting | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 3 Year Program/Total Line Miles | 1/1/2025-6/30/2025 Miles Planned | 1/1/2025-6/30/2025 Actual Miles Completed | 1/1/2025-6/30/2025 Ahead/Behind | 1/1/2025-6/30/2025 % Ahead/Behind | 1/1/2023-12/31/2025 Miles Planned | 1/1/2023-12/31/2025 Actual Miles | 01/01/2023-12/31/2025 Ahead/Behind | 1/1/2023-12/31/2025 % Ahead/Behind |
| | *column a* | *column b* | *column c* | *column d* | *column e* | *column f* | *column g* | *column h* | *column i* |
| **UTAH** | 11,069 | 1,890 | 1,362 | (528) | 72.1% | 11,069 | 8,475 | (2,594) | 76.6% |
| AMERICAN FORK | 946 | 235 | 133 | (102) | 56.7% | 946 | 554 | (392) | 58.6% |
| CEDAR CITY | 1,460 | 279 | 241 | (38) | 86.3% | 1,460 | 911 | (549) | 62.4% |
| JORDAN VALLEY | 795 | 12 | 37 | 25 | 313.4% | 795 | 565 | (230) | 71.1% |
| LAKETOWN | 186 | 0 | 0 | 0 | N/A | 186 | 186 | 0 | 100.0% |
| LAYTON | 311 | 0 | 0 | 0 | N/A | 311 | 311 | 0 | 100.0% |
| MOAB | 580 | 60 | 120 | 60 | 200.0% | 580 | 580 | 0 | 100.0% |
| OGDEN | 970 | 358 | 130 | (228) | 36.3% | 970 | 739 | (231) | 76.2% |
| PARK CITY | 538 | 80 | 0 | (80) | 0.0% | 538 | 538 | 0 | 100.0% |
| PRICE | 598 | 51 | 5 | (46) | 10.3% | 598 | 472 | (126) | 78.9% |
| RICHFIELD | 1,275 | 216 | 227 | 11 | 104.8% | 1,275 | 1,026 | (249) | 80.5% |
| SL METRO | 1,297 | 169 | 131 | (38) | 77.5% | 1,297 | 1,061 | (236) | 81.8% |
| SMITHFIELD | 599 | 113 | 89 | (25) | 78.2% | 599 | 401 | (198) | 66.9% |
| TOOELE | 507 | 127 | 78 | (49) | 61.3% | 507 | 331 | (176) | 65.3% |
| TREMONTON | 747 | 178 | 149 | (29) | 83.9% | 747 | 539 | (208) | 72.2% |
| VERNAL | 260 | 11 | 22 | 11 | 198.1% | 260 | 261 | 1 | 100.4% |

| | |
|---|---|
| Distribution cycle $/tree: | $184.34 |
| Distribution cycle $/mile: | $4,019 |
| Distribution cycle removal % | 9.89% |

**Transmission**

| Total Line Miles | Line Miles Scheduled | Line Miles Worked | Miles Ahead(behind) Schedule | % of miles completed |
|---|---|---|---|---|
| 6,612 | 436 | 83 | (352) | 19% |

Current distribution cycle began January 1, 2023 and extends until December 31, 2025.

**Notes:**

Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2024 through June 30, 2024
Column c: Actual overhead distribution pole miles worked during the period January 1, 2024 through June 30, 2024
Column d: Miles ahead or behind for the period January 1, 2024 through June 30, 2024 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2024 through June 30, 2024 ((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

Column f: Total overhead distribution pole miles planned for the period January 1, 2023 through December 31, 2025
Column g: Actual overhead distribution pole miles worked during the period January 1 2023 through December 31, 2025
Column h: Miles ahead or behind for the period January 1, 2023 through December 31, 2025 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2023 through December 31, 2025 ((column g÷f)×100). Max = 100%

# 7.2 Budget

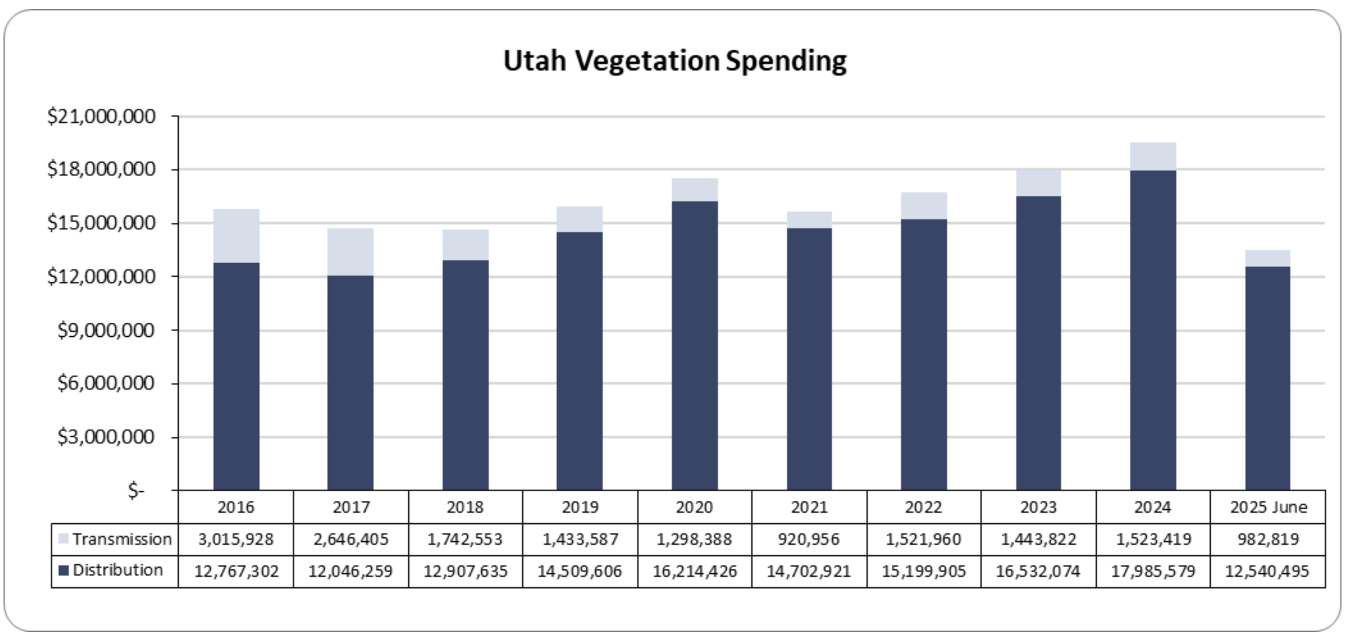
**UTAH**
**Tree Program Reporting**
**January 1, 2025 through June 30, 2025**

| | CY2023 | CY2024 | CY2025 | CY2026 (EST) |
|---|---|---|---|---|
| Distribution Tree Budget | $15,340,207 | $17,452,680 | $17,452,680 | $20,265,019 |
| Transmission Tree Budget | $1,643,600 | $1,854,753 | $1,854,753 | $2,253,056 |
| Total Tree Budget | $16,983,807 | $19,307,433 | $19,307,433 | $22,518,076 |

| | Distribution | | | Transmission | | |
|---|---|---|---|---|---|---|
| Calendar Year 2024 | Actuals | Budget | Variance | Actuals | Budget | Variance |
| Jan | $ 1,998,478 | $ 2,192,961 | -$194,484 | $ 58,906 | $ 162,582 | -$103,676 |
| Feb | $ 1,524,072 | $ 1,908,137 | -$384,066 | $ 168,288 | $ 83,693 | $84,595 |
| Mar | $ 1,895,727 | $ 1,871,610 | $24,117 | $ 128,609 | $ 92,406 | $36,203 |
| Apr | $ 2,307,701 | $ 2,156,026 | $151,674 | $ 200,359 | $ 67,347 | $133,012 |
| May | $ 2,177,406 | $ 2,593,288 | -$415,882 | $ 291,412 | $ 118,869 | $172,543 |
| Jun | $ 2,637,111 | $ 2,392,862 | $244,248 | $ 135,244 | $ 101,824 | $33,420 |
| Total | $ 12,540,495 | $ 13,114,885 | -$574,391 | $ 982,819 | $ 626,721 | $ 356,098 |

| | |
|---|---|
| Average # Tree Crews on Property (YTD) | 60 |

## 7.2.1 Vegetation Historical Spending



# 8 Standard Guarantees/Program Summary

## 8.1 Service Standards Program Summary[22]

### 8.1.1 Rocky Mountain Power Customer Guarantees[23]

| | |
|---|---|
| Customer Guarantee 1:<br>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:<br>Appointments | The Company will keep mutually agreed upon appointments, which will be scheduled within a two-hour time window. |
| Customer Guarantee 3:<br>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:<br>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:<br>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:<br>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:<br>Notification of Planned Interruptions | The Company will provide the customer with at least two days' notice prior to turning off power for planned interruptions consistent will Rule 25 and relevant exemptions. |

[22] In 2012, rules were codified in Utah Administrative Code R746-313. The Company, Commission and other stakeholders worked to develop mechanisms that comply with these rules and supersedes the Company's Service Standards Program.
[23] See Rule 25 for a complete description of terms and conditions for the Customer Guarantee Program.

### 8.1.2 Rocky Mountain Power Performance Standards[24]

| | |
|---|---|
| *Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI) | In 2020 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 107-157 minutes. |
| *Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI) | In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 0.9-1.2 events. |
| Network Performance Standard 3: Improve Under Performing System Segments | The Company will identify underperforming circuit segments and outline improvement actions and their costs and using the Open Reliability Reporting (ORR) process, evidence the outcome of the ORR process for the circuit segments chosen[25]. |
| *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. |

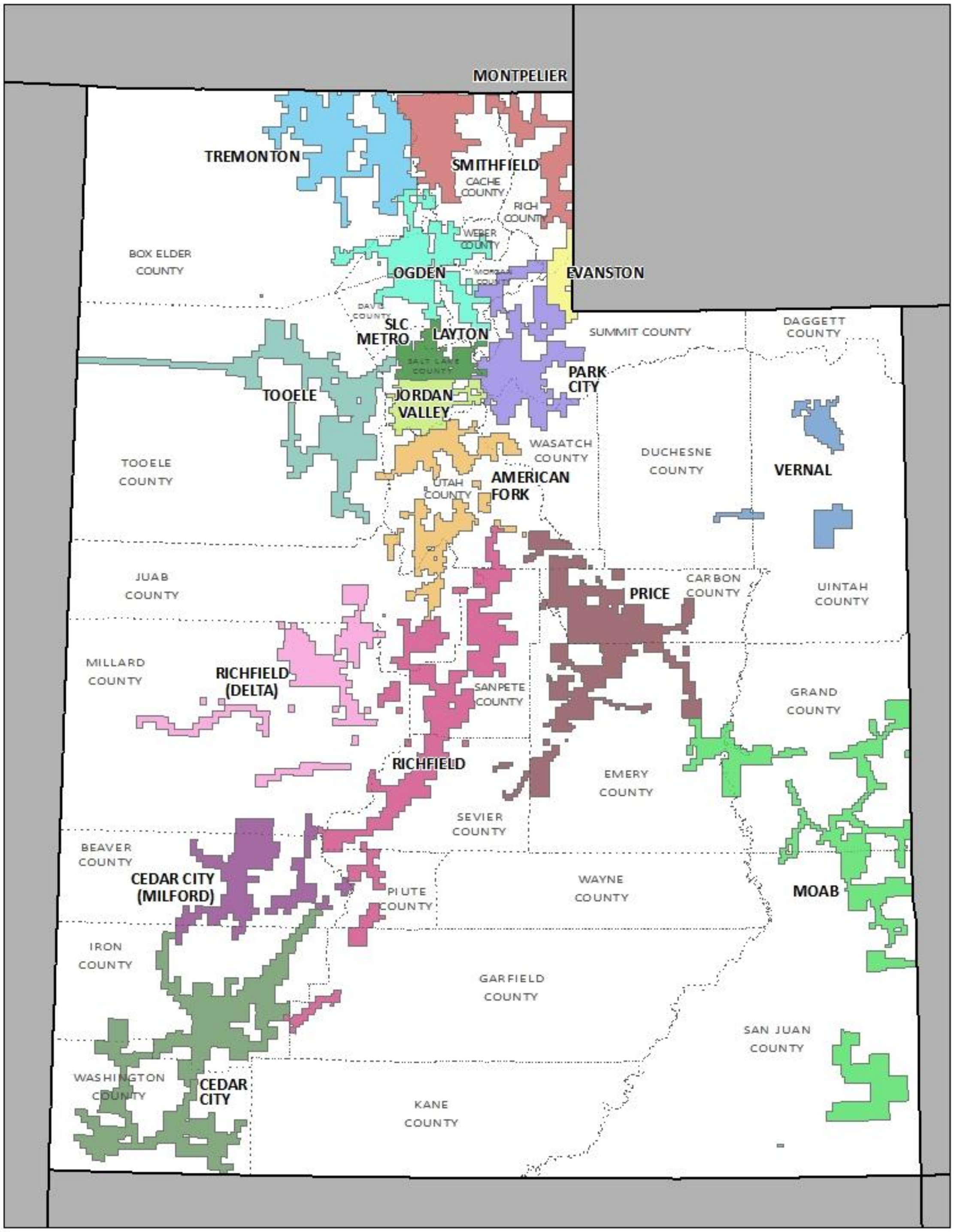
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

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

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

## 8.1.3 Utah Distribution Service Area Map with Operating Areas/Districts

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



## 8.2 Cause Code Analysis

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

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

## 8.3 Reliability Definitions

### Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[26] 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 each 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***

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 timeframe. 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.

[26] IEEE adopted Standard 1366-2003 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.

***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).

***$MAIFI_E$***

$MAIFI_E$ (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 timeframe. It is calculated by counting all momentary operations which occur within a 5-minute time period, as long as the sequence did not result in a device experiencing a sustained interruption. This series of actions typically occurs when the system is trying to re-establish energy flow after a faulted condition and is associated with circuit breakers or other automatic reclosing devices.

***Lockout***

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

***CEMI***

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

***ORR***

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

***CPI99***

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

CPI = Index * ((SAIDI * WF * NF) + (SAIFI * WF * NF) + ($MAIFI_E$ * WF * NF) + (Lockouts * WF * NF))
Index: 10.645
SAIDI: Weighting Factor 0.30, Normalizing Factor 0.029
SAIFI: Weighting Factor 0.30, Normalizing Factor 2.439

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

### *CPI05*

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

## Performance Types

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

### *Major Events*

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

| Effective Date | Customer Count | ME Threshold SAIDI | ME Customer Minutes Lost |
|---|---|---|---|
| 1/1-12/31/2025 | 1,054,136 | 3.83 | 4,036,570 |

### *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, enhanced safety settings (ESS), emergency de-energization, prearranged (which can include short notice emergency prearranged outages), customer requested interruptions and forced outages mandated by public authority typically regarding safety in an emergency.

**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.