UTAH

SERVICE QUALITY

REVIEW

January 1 – June 30, 2007

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 some cases, Rocky Mountain Power has decided to exceed these industry standards. 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.

1 Service Standards Program Summary

Effective April 1, 2005 through March 31, 2008

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.

1.2 Rocky Mountain Power Performance Standards

Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	The Company will improve SAIDI by 6% by March 31, 2008.
Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	The Company will improve SAIFI by 6% by March 31, 2008.
Network Performance Standard 3: Improve Under Performing Circuits	The Company will reduce by 20% the circuit performance indicator (CPI) for a maximum of five under performing 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 on average to 80% of customers within three hours.
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.

1.3 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE P1366-2003[1] Standard for Reliability Indices.

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

Momentary Outage
A momentary outage is defined as an outage of less than 5 minutes in duration. Rocky Mountain Power has historically captured this data using substation breaker fault counts.

Reliability Indices

SAIDI
SAIDI (sustained 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 time-frame. 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 P1366-2003. 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 (sustained 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.

CEMI
CEMI is an acronym for Customers Experiencing Multiple (Sustained and Momentary) 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 (such as SAIDI and SAIFI) to identify underperforming circuits. It excludes Major Event and Loss of Supply or Transmission outages.

CPI05
CPI05 is an acronym for Circuit Performance Indicator, which uses key reliability metrics (such as SAIDI and SAIFI) to identify underperforming circuits. Unlike CPI99 it includes Major Event and Loss of Supply or Transmission outages.

[1] P1366-2003 was adopted by the IEEE on December 23, 2003. 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.

Performance Types & Commitments

Rocky Mountain Power recognizes two categories of performance: underlying performance and major events. Major events represent the atypical, with extraordinary numbers and durations for outages beyond the usual. Ordinary outages are incorporated within underlying performance. These types of events are further defined below.

Major Events

A Major Event is defined as a 24-hour period where SAIDI exceeds a statistically-derived threshold value (Reliability Standard IEEE P1366-2003[2]) based on the 2.5 beta methodology.

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 (with some minor considerations for changes in reporting practices) for establishing and evaluating meaningful performance trends over time.

Post-Merger Commitment Target

Because of the benefits that the Company and its customers and regulators experienced from the Service Standards Program, the Company filed and received approval to continue the program through 3/31/2008. From a reliability perspective, the Company continues to develop stretch goals that will deliver important improvements to its customers.

[2] P1366-2003 was adopted by the IEEE on December 23, 2003. 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

2 POST MERGER PERFORMANCE STANDARDS

2.1 System Average Interruption Duration Index (SAIDI)

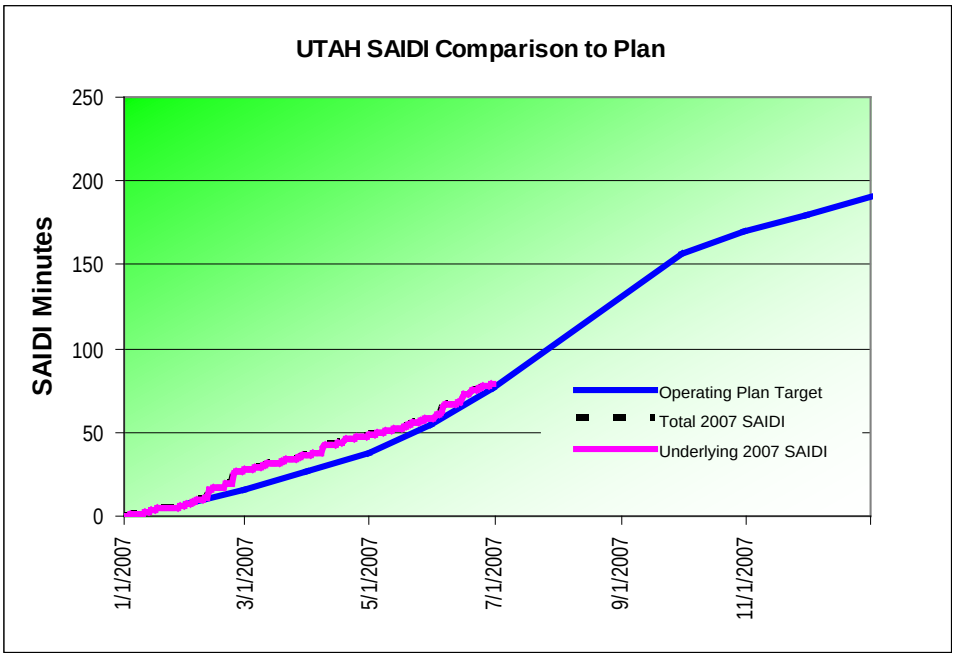
During the reporting period, the Company experienced reliability results essentially at operating plan target for sustained outage duration and sustained outage frequency. During the period, three significant event days[3] were recorded. In total they account for approximately 15 minutes of the half-year's results.

Date	SAIDI (Minutes)	Primary Cause of Event
February 4, 2007	4.8	Weather/contamination-initiated pole fires
February 23, 2007	6.4	Weather/snow, sleet resulting in loss of supply & pole fires
April 8, 2007	4.0	Weather/spring storm, including lightning

Also during this period, no major events were experienced or filed.

At the end of June 30, 2007, the company has met a 12 month calendar result for its modified Performance Standards Program interruption duration (SAIDI) commitment level and its interruption frequency (SAIFI) commitment level. It intends to complete a formal filing notifying the Commission of this accomplishment during the last quarter of 2007.

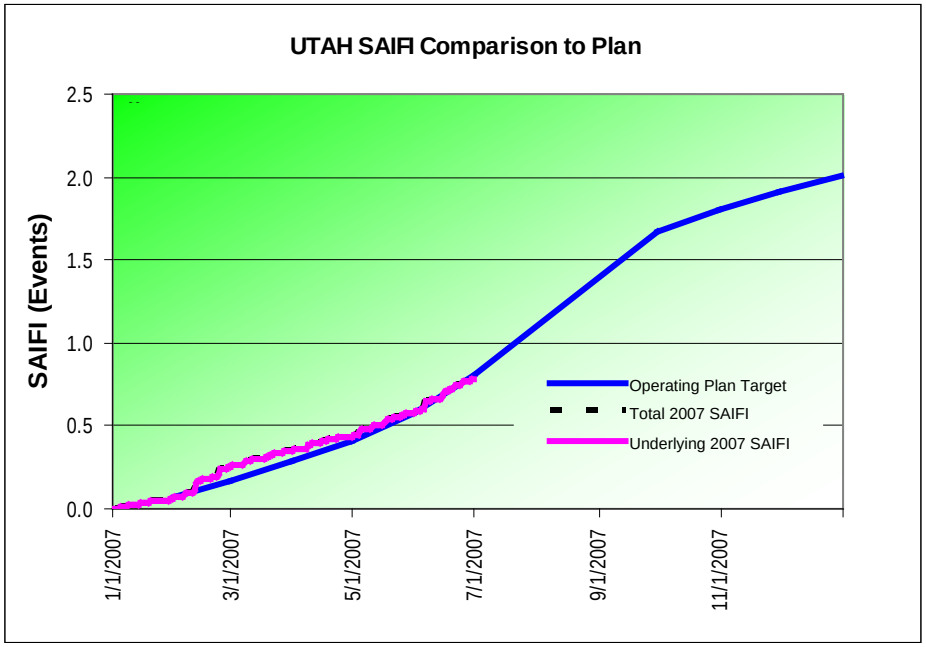
SAIDI	January 1 through June 30, 2007					
	Qtr 1		Qtr 2		Year to Date	
	Actual	Plan	Actual	Plan	Actual	Plan
Utah Total	36	27	43	50	79	77



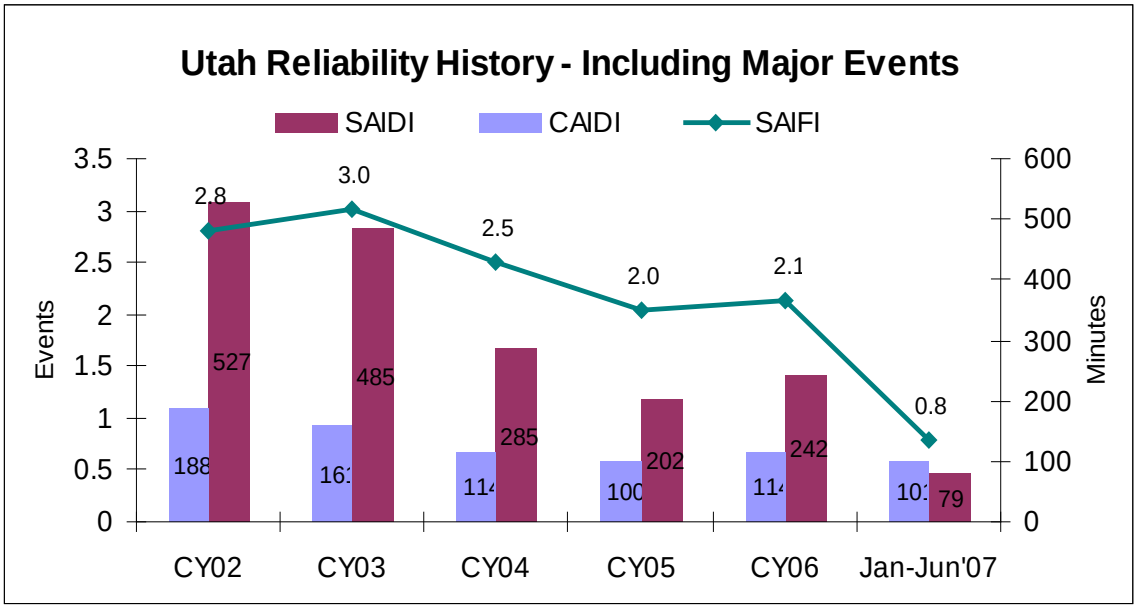
[3] On a trial-use basis the company has established a variable of 1.75 times the standard deviation of its natural log SAIDI results.

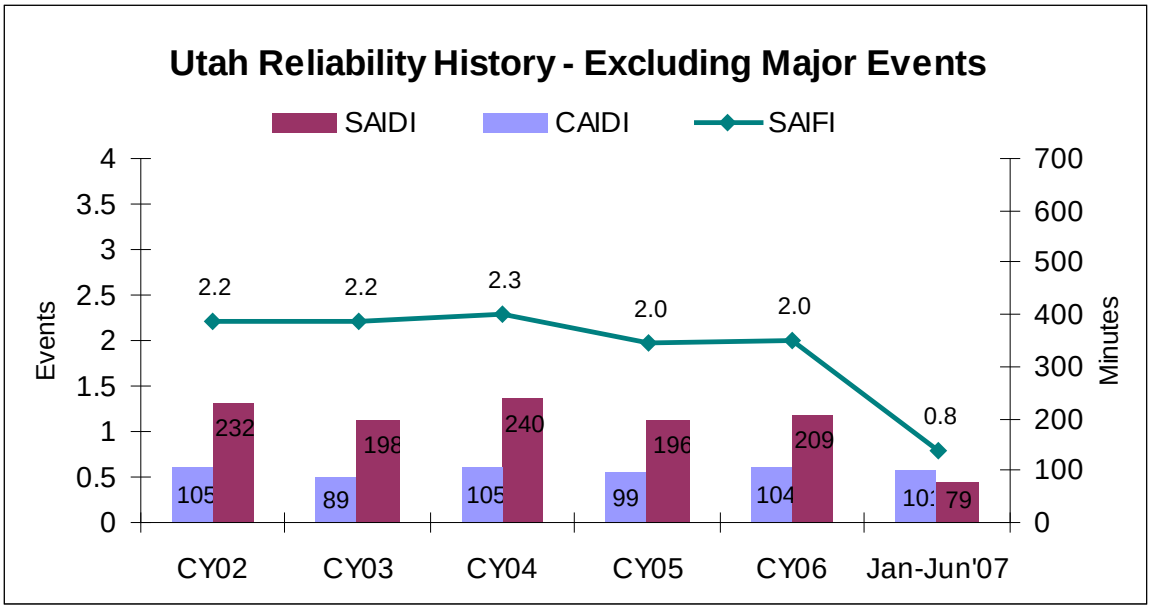
2.2 System Average Interruption Frequency Index (SAIFI)

SAIFI	January 1 through June 30, 2007					
	Qtr 1		Qtr 2		Year to Date	
	Actual	Plan	Actual	Plan	Actual	Plan
Utah Total	0.352	0.29	0.434	0.52	0.786	0.81



2.3 Reliability History





2.4 Cause Code Analysis

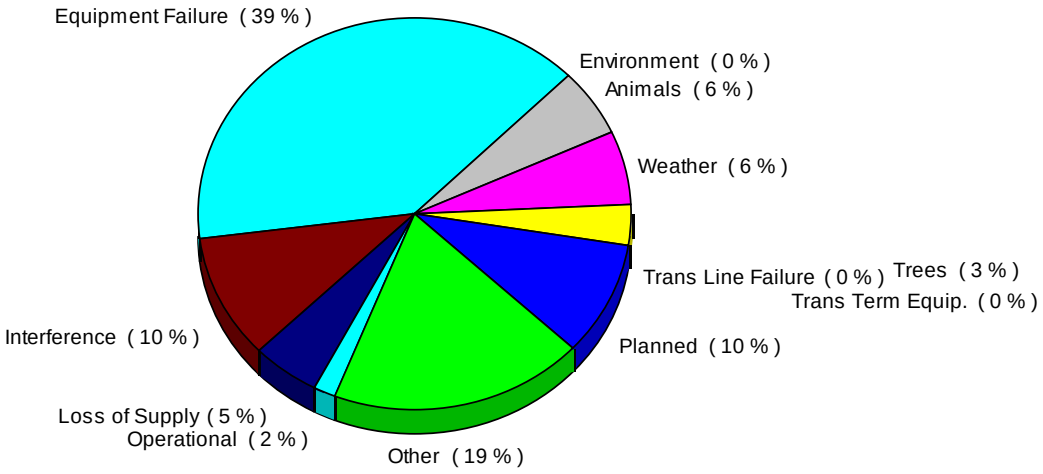
Certain types of outages typically result in a large amount of customer minutes lost, but are infrequent, such as Loss of Supply outages. Others tend to be more frequent, but result in few customer minutes lost.

The table below is a breakdown of SAIDI[4] and SAIFI by each direct cause category for the reporting period. The charts on the next page show the percentages of incidents, customer minutes lost and sustained customer interruptions attributed to each direct cause category. Following the charts, a table of definitions provides descriptive examples for each direct cause category.

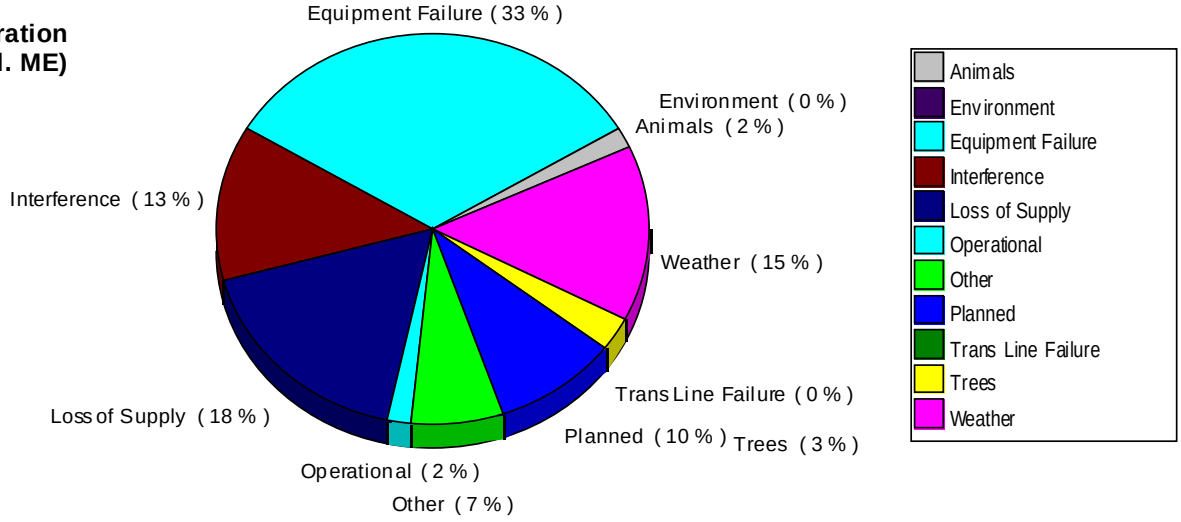
Direct Cause Category	SAIDI	SAIFI	Sustained Interrupts
Animals	1	0.015	525
Environment	0	0.000	23
Equipment Failure	26	0.195	3,719
Interference	10	0.097	987
Loss of Supply	14	0.182	474
Operational	1	0.018	150
Other	5	0.080	1811
Planned	8	0.116	919
Trans Line Failure	0	0.000	21
Trans Term Equip.	0	0.000	8
Trees	2	0.020	292
Weather	12	0.063	553
TOTAL	79	0.786	9,482

[4] 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 802,569 (2007 Utah frozen customer count). For example, 79 minutes of SAIDI results in 79 * 802,569 = 63,402,951 customer minutes lost. By the same calculation, 0.786 SAIFI results in 0.786*802,569 = 630,819 sustained customer interruptions.

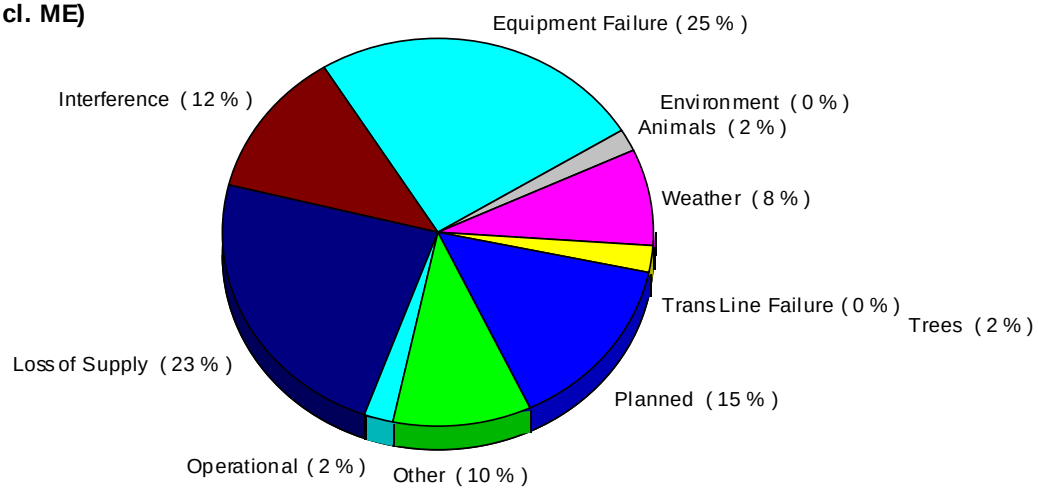
Incidents (excl. ME)



Outage Duration (SAIDI excl. ME)



Outage Frequency (SAIFI excl. ME)



Outage Dura
(SAIDI excl. ME)

Outage Frequency
(SAIFI excl. ME)

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 Rocky Mountain Power or Rocky Mountain Power'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.
Trans Line Failure	(Transmission Line Failure) Failure of transmission line
Trans Term Equipt	(Transmission Termination Equipment) Failure of equipment at either end of a transmission line, such as at the transmission or distribution substation

2.5 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 time-frame. 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 targeted improvement. The improvements 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).

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 6/30/07
Circuit Performance Indicator 2005 (CPI05)			
Program Year 8: (CY2007)			
Brian Head 11	In Development	412	
McClelland 12	In Development	220	
Union 16	In Development	128	
Enoch 12	In Development	186	
Quail Creek 12	In Development	1094	
Program Year 7: (CY2006)			
Tooele 12	Underway	228	
Box Elder 12	Underway	319	
Oakley 11	Underway	367	
Brighton 12	Underway	608	
Timber Lakes 11	Underway	309	
Program Year 6: (CY2005)			
Cudahy 11	COMPLETE	908	832
Garden City 12	COMPLETE	521	379
Black Mountain 11	COMPLETE	406	714
Uinta 13	COMPLETE	367	174
West Roy 14	COMPLETE	354	200
Circuit Performance Indicator 1999 (CPI99)			
Program Year 5: (CY2004)			
Dumas 16	COMPLETE	1,312	218
West Com 11	COMPLETE	1,035	62
Quarry 15	COMPLETE	735	218
Brooklawn 12	COMPLETE	557	355
North Bench 13	COMPLETE	225	151
Program Year 4: (CY2003)			
Toquerville 32	COMPLETE	1,596	725

Toquerville 31	COMPLETE	1,016	783
Saratoga 13	COMPLETE	885	189
Nibley 21	COMPLETE	465	191
Middleton 24	COMPLETE	823	666
Program Year 3: (CY2002)			
University 1	COMPLETE	344	0
West Cedar	COMPLETE	4,306	680
Parowan Valley 25	COMPLETE	1,121	3,686
Eureka 12	COMPLETE	3,397	101
Coleman 15	COMPLETE	1,574	183

2.6 Supply Restoration

2.6.1 Restore Service to 80% of Customers within 3 Hours (across 3 years)

UTAH RESTORATIONS WITHIN 3 HOURS					
Cumulative 3-Year Program-to-date					86%
Cumulative January 1 – June 30, 2007					89%
January	February	March	April	May	June
83%	90%	91%	84%	92%	88%
July	August	September	October	November	December

2.7 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	82%
PS6a) Respond to commission complaints within 3 days	95%	100%
PS6b) Respond to commission complaints regarding service disconnects within 4 hours	95%	100%
PS6c) Resolve commission complaints within 30 days	100%	100%

3 CUSTOMER GUARANTEES

3.1 Utah State Customer Guarantee Summary Status

customer*guarantees*

January to June 2007

Utah

	Description	2007 Events	2007 Failures	2007 %Success	2007 Paid	2006 Events	2006 Failures	2006 %Success	2006 Paid
CG1	Restoring Supply	631,766	3	99.9%	$150	870,079	1	99.9%	$75
CG2	Appointments	4,825	10	99.8%	$500	4,323	12	99.7%	$600
CG3	Switching on Power	5,957	12	99.8%	$600	7,324	13	99.8%	$650
CG4	Estimates	1,129	11	99.0%	$550	1,120	25	97.8%	$1,250
CG5	Respond to Billing Inquiries	4,170	5	99.9%	$250	2,974	12	99.6%	$600
CG6	Respond to Meter Problems	517	4	99.2%	$200	419	1	99.8%	$50
CG7	Notification of Planned Interruptions	32,408	26	99.9%	$1,300	25,713	12	99.9%	$600
		680,772	**71**	**99.9%**	**$3,550**	**911,952**	**76**	**99.9%**	**$3,825**

Overall Guarantee performance remains above 99%, demonstrating Rocky Mountain Power's continued commitment to customer satisfaction.

One reconnect for credit was not reconnected within twenty-four hours. Credit customers are exempted from CG3; however, the company attempts to reconnect these customer's within twenty-four hours.

Major Events are excluded from the Customer Guarantees program.

4 MAINTENANCE COMPLIANCE TO ANNUAL PLAN

4.1 T&D Preventive and Corrective Maintenance Programs

Preventive Maintenance

The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions, and perform appropriate preventive actions upon those facilities.

Transmission and Distribution lines have a combination of preventive maintenance programs.

- Safety inspections are designed to identify damage or defects that may endanger public safety or adversely affect the integrity of the electric system. (2 year cycle distribution and sub-transmission, 1 year cycle main grid)
- Detailed inspections are careful visual inspections of each structure and the spans between each structure.[5]
- Pole test and treat includes intrusive tests performed on wood poles to determine the strength of the pole, with subsequent application of chemicals or other measures to maximize the lifespan of the pole. (20 year cycle)

Substations and Major Equipment

- Rocky Mountain Power inspects all substations to ascertain all components within the substation are operating as expected. These components can include breaker counters or target levels, which are critical information in monitoring the equipment. Abnormal conditions that are identified are prioritized for repair (corrective maintenance). (Monthly cycle)
- Rocky Mountain Power also performs minor maintenance or overhauls on major substation equipment based on elapsed time or number of equipment operations, also to maximize the lifespan of this major equipment. (Based upon type of equipment)

Corrective Maintenance

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

Transmission and Distribution Lines

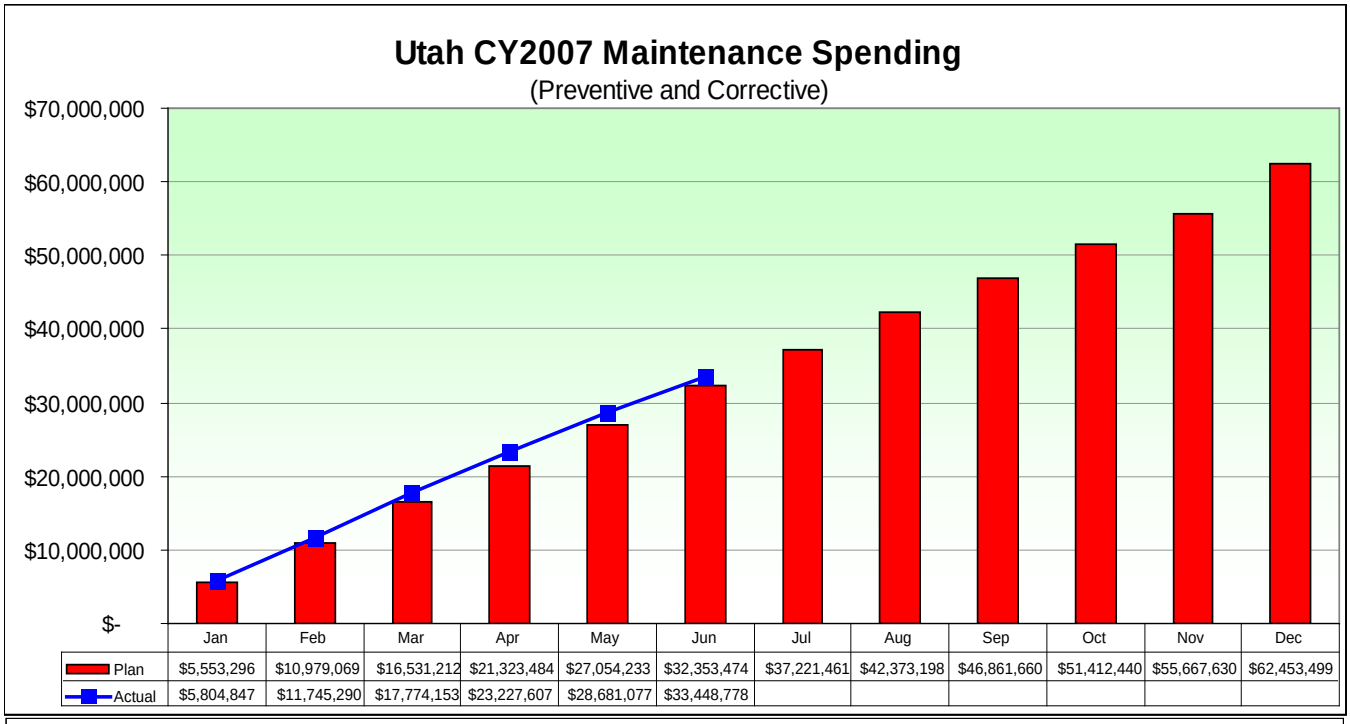
- Correctable conditions are identified through the preventive maintenance process.
- Outstanding conditions are recorded in a database and remain until corrected.

Substations and Major Equipment

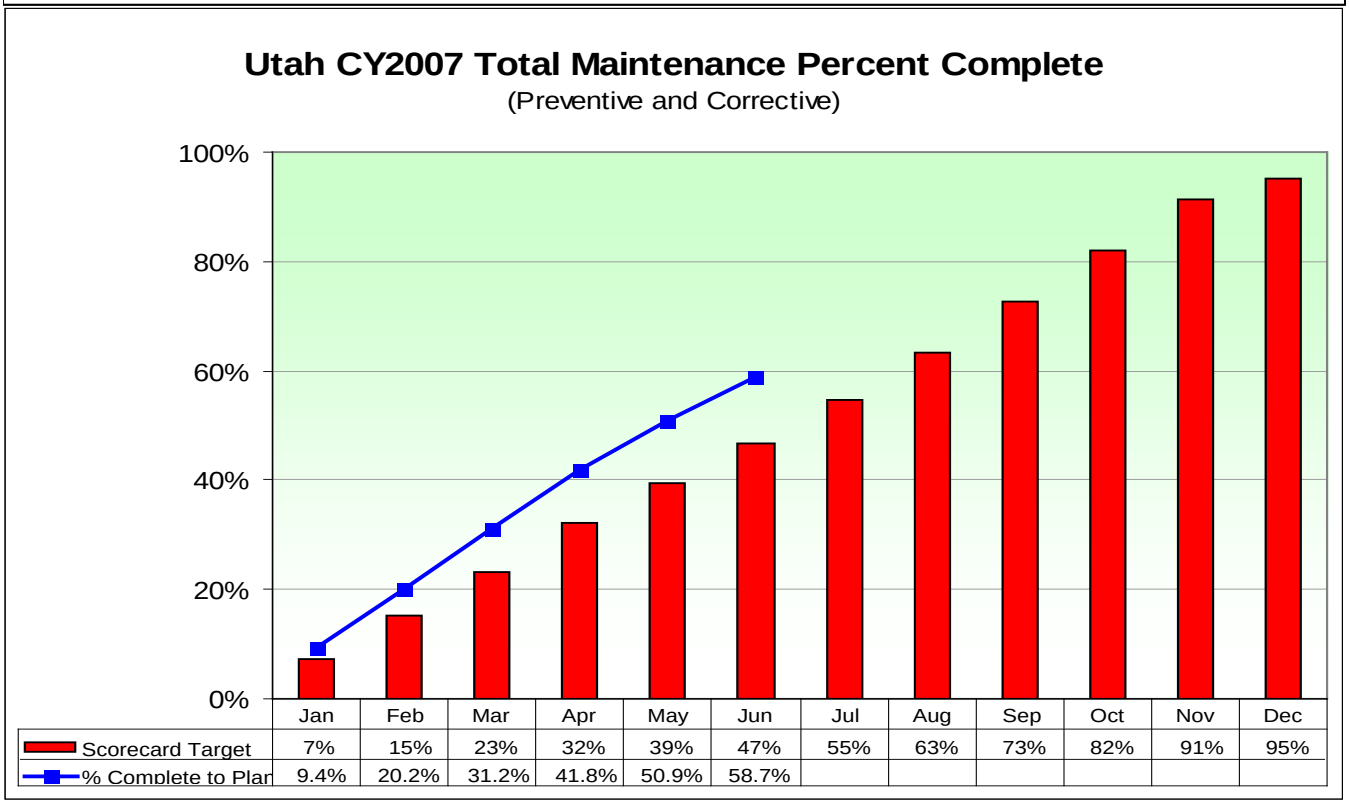
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

[5] Effective 1/1/2007 Rocky Mountain Power modified its reliability & preventative planning methods to utilize repeated reliability events to prioritize localized preventative maintenance activities, using its Customers Experiencing Multiple Interruptions (CEMI) Planning methodology. Repeated outage events experienced by customers will result in localized inspection and correction activities, rather than all programmatic inspections and corrections being performed at either the entire circuit or map section level.

4.2 Maintenance Spending

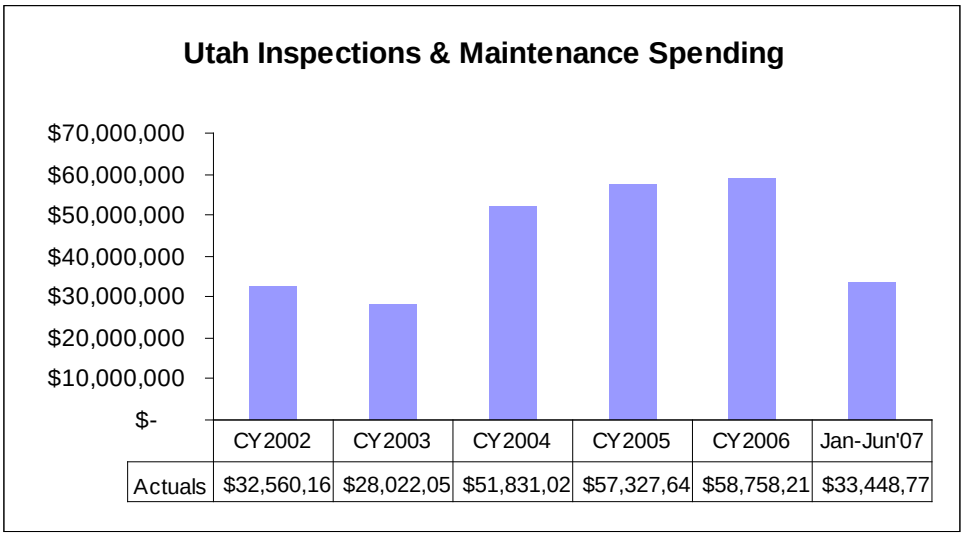


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,553,296	$10,979,069	$16,531,212	$21,323,484	$27,054,233	$32,353,474	$37,221,461	$42,373,198	$46,861,660	$51,412,440	$55,667,630	$62,453,499
Actual	$5,804,847	$11,745,290	$17,774,153	$23,227,607	$28,681,077	$33,448,778						



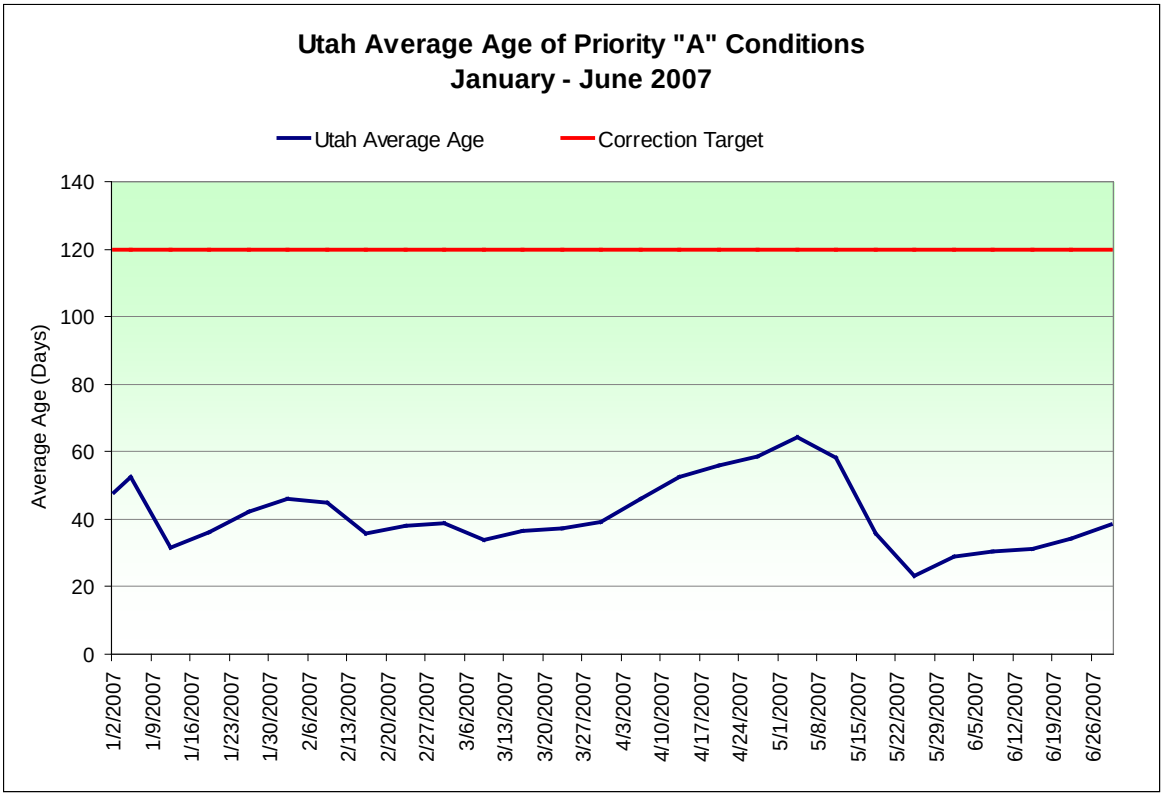
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scorecard Target	7%	15%	23%	32%	39%	47%	55%	63%	73%	82%	91%	95%
% Complete to Plan	9.4%	20.2%	31.2%	41.8%	50.9%	58.7%						

4.2.1 Maintenance Historical Spending



4.3 T&D Priority "A" Conditions Correction History & Compliance

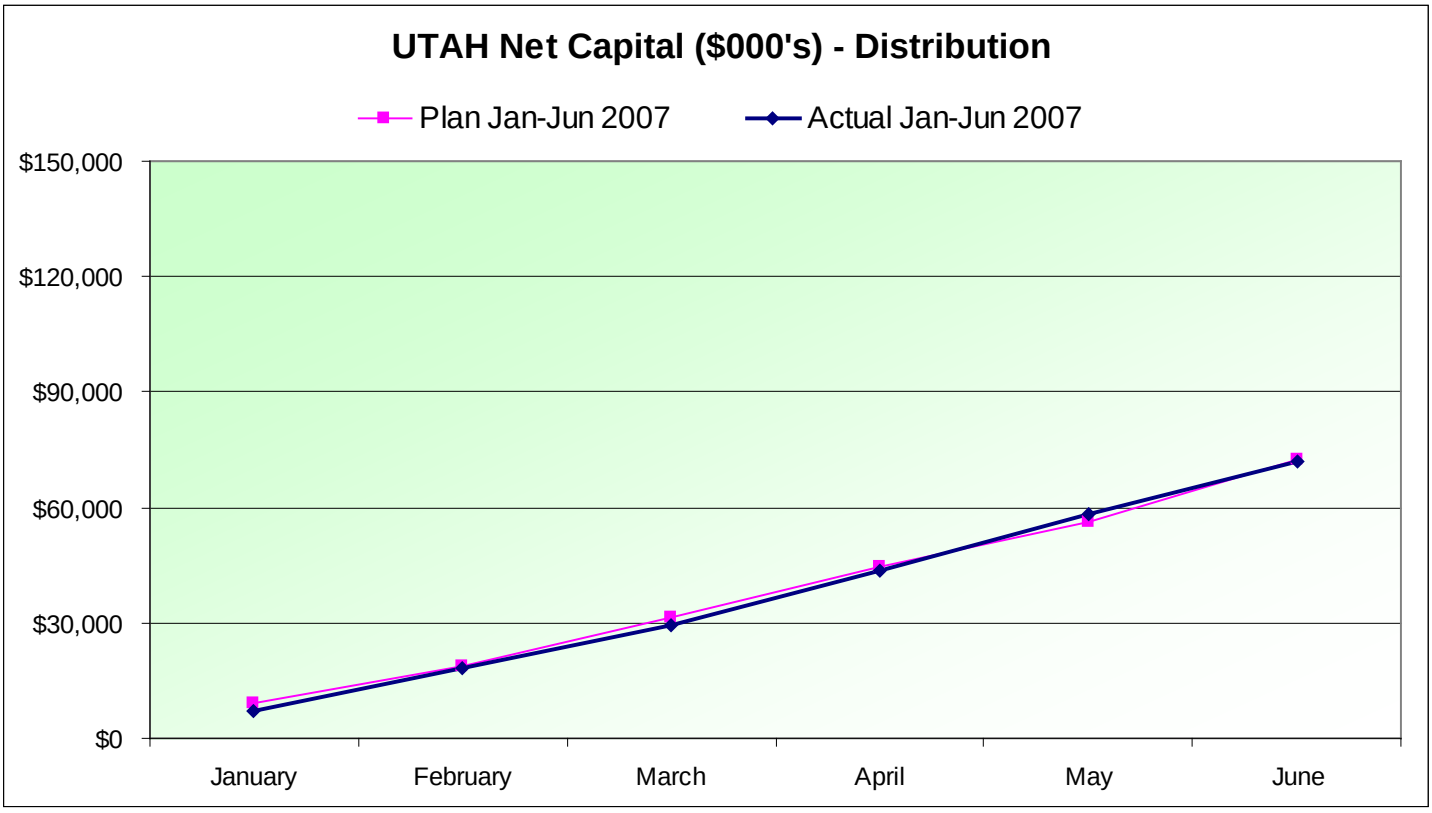
The company reports its compliance for the average age of A priority corrections. As can be seen, on a weekly basis, the average age of corrected conditions ranges from about 22 days to 63 days; compliance to the target has been consistently delivered.



5 CAPITAL INVESTMENT

5.1 Capital Spending - Distribution

Investment Area	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	4.3	3.6	Highway Relocation work $0.7M over plan, Public Accom. $0.4M over plan; offset by Ovhd/Undgd Conversions $0.4M under plan,
2. New Connects	27.9	17.7	Residential $4.5M over plan, Commercial $2.7M over plan, Industrial $2.4M over plan, Irrigation $0.4M over plan, and Street Lights & Other $0.2M over plan.
3. System Reinforcement	19.2	24.1	Substations $6.5 under plan; partially offset by Subtransmission $1.4M over plan, Feeders $0.2M over plan
4. Replacements	15.4	12.5	Storm & Casualty $1.9M over plan, Replace Substation Transformers $1.4M over plan, Vehicles $1.1M over plan, Overhead Distribution Lines - Poles was $0.9M over plan; partially offset by Underground Cable $1.5M under plan, Other General Plant $1.1M under plan
6. Upgrades & Modernize	5.2	14.4	Automated Meter Reading Wasatch Front $10.0M under plan; partially offset by Feeder Improvements $1.0M over plan, Vehicle Upgrades $0.5M over plan
Total - Distribution	**72.0**	**72.4**	

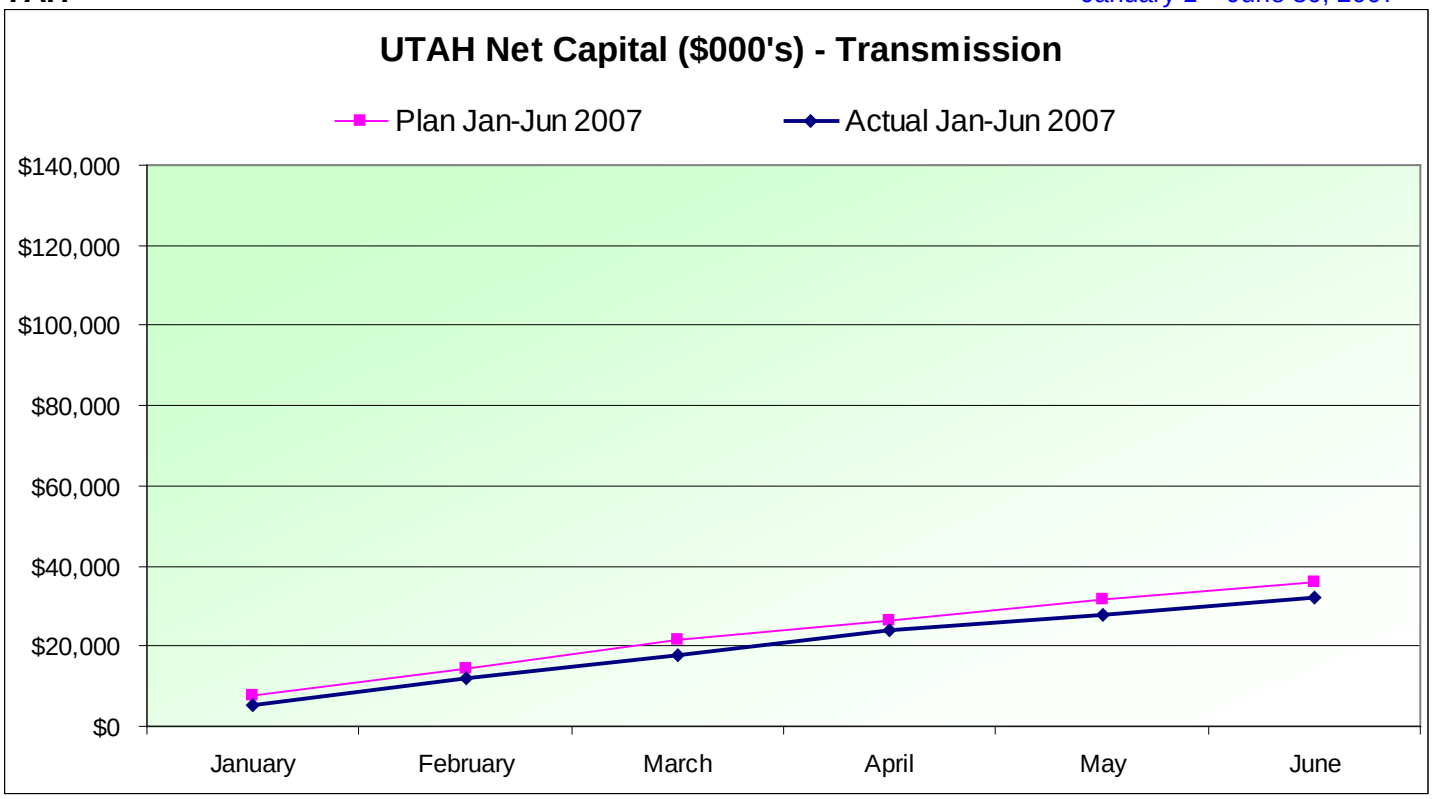


5.2 Capital Spending - Transmission

Investment Area	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	1.0	1.3	Highway Relocations $0.5M under plan, Community Relations $0.3M under plan; partially offset by Public Accommodations $0.4M over plan
2. System Reinforcement	7.5	4.7	Ben Lomond Term Acquire Trans ROW $3.5M over plan, Three Mile Knoll Sub: New 345-138kV Sub $3.2M over plan, Cache Valley Add. Bridgerland Sw St Ph 1 $2.4M over plan, Path 18 Reliability Improvements $0.5M over plan;partially offset by Cedar City Install 345kV Source SW Utah $0.9M under plan, Craner Flat Substation - Install 138 kV $0.8M under plan, Chappel Creek 230kV 25MVAR Capacitor $0.4M under plan, Thief Creek - Silver Crk 138-230kV Line $0.3M under plan
3. Replacements	3.4	4.6	Overhead Transmission Lines Poles $0.7M under plan, Storm & Casualty $0.4M over plan
4. Upgrades & Modernize	2.0	2.7	Transmission Improvements - $0.7M under plan, Substation Improvements 40.2M under plan; partially offset by Spare Equipment - $0.1M over plan
Total - Trans. Excl. IRP & Interconnections	**14.0**	**13.3**	
5. IRP & Interconnections	17.7	22.5	Summit Vineyard Transmission project $3.1M under plan, Shute Creek to Mona System Upgrade $1.2M under plan, Bridger 5 345kV JB to Wasatch Front $1.1M under plan, Mona-Oquirrh Line $0.9M under plan, Camp Williams-Mona #4 345kV - $0.8M under plan
Total - Transmisssion	**31.6**	**35.8**	

UTAH

January 1 – June 30, 2007



Utah Count of New Connects

Jan-Jun 2007

	Jan - Jun 2006	Jan	Feb	Mar	Jan-Mar Total	Apr	May	Jun	Apr-Jun Total	Jan-Jun Total
Residential										
Utah South	1,013	125	120	164	409	205	135	182	522	931
Utah North	2,815	582	563	620	1,765	532	472	361	1,365	3,130
Utah Central	4,461	780	778	1,064	2,622	952	933	752	2,637	5,259
Total Residential	**8,289**	**1,487**	**1,461**	**1,848**	**4,796**	**1,689**	**1,540**	**1,295**	**4,524**	**9,320**
Commercial										
Utah South	152	37	23	20	80	33	23	24	80	160
Utah North	552	111	121	77	309	96	109	82	287	596
Utah Central	743	123	96	170	389	136	168	153	457	846
Total Commercial	**1,447**	**271**	**240**	**267**	**778**	**265**	**300**	**259**	**824**	**1,602**
Industrial										
Utah South	13	-	-	-	-	-	3	-	3	3
Utah North	3	-	-	1	1	-	-	-	-	1
Utah Central	6	1	-	-	1	1	-	1	2	3
Total Industrial	**22**	**1**	**-**	**1**	**2**	**1**	**3**	**1**	**5**	**7**
Irrigation										
Utah South	25	-	-	10	10	12	9	11	32	42
Utah North	3	-	-	-	-	2	3	-	5	5
Utah Central	18	-	1	-	1	1	5	1	7	8
Total Irrigation	**46**	**-**	**1**	**10**	**11**	**15**	**17**	**12**	**44**	**55**
Total New Connects										
Utah South	1,203	162	143	194	499	250	170	217	637	1,136
Utah North	3,373	693	684	698	2,075	630	584	443	1,657	3,732
Utah Central	5,228	904	875	1,234	3,013	1,090	1,106	907	3,103	6,116
Total New Connects	**9,804**	**1,759**	**1,702**	**2,126**	**5,587**	**1,970**	**1,860**	**1,567**	**5,397**	**10,984**

6 VEGETATION MANAGEMENT

6.1 Production

UTAH
Tree Program Reporting
January 1, 2007 through July 1, 2007
Distribution

	3 Year Program/Total Line Miles *column a*	1/1/2007-07/01/2007 Miles Planned *column b*	1/1/2007-07/01/2007 Actual Miles *column c*	01/01/2007-07/01/2007 Ahead/Behind *column d*	1/1/2007-07/01/2007 % Ahead/Behind *column e*	4/1/2005-07/01/2006 Planned Miles *column f*	4/1/2005-07/01/2007 Actual Miles *column g*	1/1/2007-07/01/2007 Ahead/Behind *column h*	4/1/2005-07/01/2007 % Ahead/Behind *column i*
UTAH	10,912	1,700	1,965	265	115.6%	8,067	8,526	459	106%
AMERICAN FORK	848	163	265	102	162.6%	636	791	155	124%
CEDAR CITY	1,353	195	186	-9	95.4%	1015	733	-282	72%
JORDAN VALLEY	817	136	205	69	150.7%	613	635	22	104%
LAYTON	285	70	70	0	100.0%	213	297	84	139%
MOAB	922	45	90	45	200.0%	691	955	264	138%
OGDEN	882	151	207	56	137.1%	661	716	55	108%
PARK CITY	527	58	56	-2	96.6%	395	426	31	108%
PRICE	571	36	18	-18	50.0%	428	518	90	121%
RICHFIELD	1,311	235	163	-72	69.4%	983	940	-43	96%
SL METRO	1,206	159	183	24	115.1%	904	764	-140	85%
SMITHFIELD	565	67	111	44	165.7%	424	408	-16	96%
TOOELE	462	93	153	60	164.5%	347	383	36	110%
TREMONTON	725	234	183	-51	78.2%	544	532	-12	98%
VERNAL	438	58	75	17	129.3%	213	428	215	201%

Distribution cycle $/tree: $46.30
Distribution cycle $/mile: $3,549
Distribution cycle removal % 48.6%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,197	1612	895	-87	6,110	99%

Transmission $/mile: $1,447

Notes:
Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2007 through December 31, 2007
Column c: Actual overhead distribution pole miles worked during the period January 1, 2007 through July 1, 2007
Column d: Miles ahead or behind for the period April 1, 2006 through December 31, 2006 (column c-column b)
Column e: Percent of actual compared to planned for the period April 1, 2006 through December 31, 2006 ((column c÷b)×100)
Column f: Planned miles cycle to date (April 1, 2005 through December 31, 2006)
Column g: Actual miles cycle to date (April 1, 2005 through December 31, 2006) - Cycle to date
Column h: Miles ahead or behind for the period April 1, 2005 through December 31, 2006 (column g-column f) - cycle to date
Column i: Percent of actual compared to planned for the period April 1, 2005 through December 31, 2006 ((column g÷f)×100) - cycle progress to date

6.2 Budget

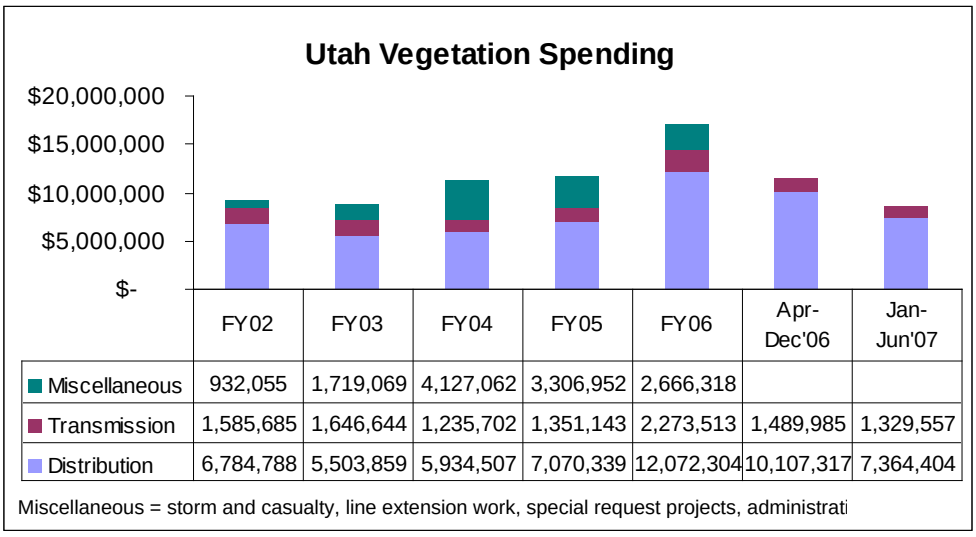
UTAH

Tree Program Reporting

	CY2008	CY2009	CY2010
Distribution			
Tree Budget	$12,865,374	$12,865,374	$12,865,374
Transmission			
Tree Budget	$3,313,042	$3,313,042	$3,455,503
Total Tree Budget	$16,178,416	$16,178,416	$16,320,877

	Distribution			Transmission		
	Actuals	**Budget**	**Variance**	**Actuals**	**Budget**	**Variance**
Calendar year 2007						
Jan	$1,290,055	$1,300,830	-$10,775	$70,615	$182,655	-$112,040
Feb	$1,519,518	$1,692,792	-$173,274	$236,888	$152,214	$84,674
Mar	$1,115,468	$1,084,025	$31,443	$150,420	$152,214	-$1,794
Apr	$1,200,755	$1,084,025	$116,730	$261,136	$152,214	$108,922
May	$1,145,413	$1,300,830	-$155,417	$289,357	$182,657	$106,700
Jun	$1,093,194	$1,084,025	$9,169	$321,142	$152,214	$168,928
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$7,364,404	$7,546,527	-$182,123	$1,329,557	$974,168	$355,389
Average # Tree Crews on Property (YTD)			87			

6.2.1 Vegetation Historical Spending



	FY02	FY03	FY04	FY05	FY06	Apr-Dec'06	Jan-Jun'07
Miscellaneous	932,055	1,719,069	4,127,062	3,306,952	2,666,318		
Transmission	1,585,685	1,646,644	1,235,702	1,351,143	2,273,513	1,489,985	1,329,557
Distribution	6,784,788	5,503,859	5,934,507	7,070,339	12,072,304	10,107,317	7,364,404

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