

Utah Service Quality Review Group

Report to the

Utah Public Service Commission

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**Submitted by
Utah Service Quality Review Group Members**

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SERVICE QUALITY REVIEW GROUP REPORT

INTRODUCTION

The Service Quality Task Force was created in Docket No. 04-035-45, Stipulation Regarding Revenue Requirement, Rate Spread, and Rate Design, which the Commission adopted. The tasks that this stipulation charged the Task Force with were later augmented by the Commission Memorandum dated June 24, 2005 in Docket No. 04-035-01. The Division of Public Utilities (Division) gleaned from these two documents that the Task Force was charged with

1. Reviewing PacifiCorp's (Company) Utah system performance and support;
2. Reviewing the appropriateness of the Service Quality Standards (SQS)
3. Reviewing ongoing investment and maintenance plans;
4. Identifying possible improvements that could be made in the Company's Utah distribution system to provide appropriate service quality while incurring reasonable costs;
5. Conducting cost-benefit analysis of increasing the design and operational limits in Utah Power's distribution network, particularly those areas that experience more frequent outages;
6. Considering the major event definition used in network performance reporting and the network's reliability statistics to determine whether the application of the definition and information provided using the definition is most useful in assessing the provision of electric service consistent with regulatory policy and public intent goals.

Prior to the first meeting the Division asked all the parties in the service list of Docket No. 04-035-01 to submit any issues they would like addressed by the Task Force. The first meeting was held on June 2, 2005. In this meeting, the goals and objectives of the Task Force, some

preliminary issues identified by the Division and a reporting outline proposed by PacifiCorp were discussed. The Division's preliminary issues list is as follows:

1. What SQS are currently in place for Utah?
2. Are the current SQS adequate?
3. How should we treat the SQS – do we need to create (recommend) rules to the Commission or is the current treatment adequate?
4. How do Utah's Service Quality Standards compare to those in other States?
5. Once SQS are established, how do we use them – e.g., can SQS be used as a benchmark for rate case outcomes?
6. What is the status of distribution facilities?
7. What maintenance plans and investments are in place? Are they adequate?

The reporting outline proposed by PacifiCorp is as follows:

1. Post Merger Performance Standards:
 - a. Improve SAIDI by 6% within 3 years;
 - b. Improve SAIFI by 6% within 3 years;
 - c. Reduce CPI annually for 5 under-performing circuits by 20% within 5 years of selection;
 - d. Restore service to 80% of customers within 3 hours (across 3 years);
 - e. Achieve telephone service level of 80/30. Add monitoring of quality of service based on customer transaction surveys and report performance.
2. Customer Guarantees:
 - a. Restoring supply after an outage;

- b. Appointments;
 - c. Switching on power;
 - d. Estimates for new supply;
 - e. Responding to bill inquiries;
 - f. Resolving meter problems;
 - g. Notifying of planned interruptions.
3. Maintenance Compliance to Annual Plan
- a. Percent compliance of preventative and corrective maintenance;
 - b. Dollar variance to plan by maintenance categories.
4. Capital Investment
5. Vegetation Management
- a. Semi-annual report on vegetation management operations.

The group agreed that PacifiCorp should provide detailed information about the items listed in its proposed reporting outline during the next meeting (July 21, 2005). This presentation was expected to bring everybody on the same playing field so that participants would have greater appreciation of the issues. This would allow the group to develop an issues list and set out a work plan for any analysis that needed to be done and establish a time schedule for the group.

On July 21, 2005, the second meeting was held in which PacifiCorp presented its first quarterly report covering its post merger performance standards and customer guarantees, major event definition, maintenance compliance to annual plan (Utah Transmission and Distribution (T&D) preventative and corrective maintenance programs and spending), capital investments on T&D, and a snapshot of vegetation management actions taken by PacifiCorp. PacifiCorp promised to provide its vegetation management semi-annual report upon completion of the half year. The group was expected to review PacifiCorp's handouts and discussion and provide their

comments or formulate the issues that they would like the group to address. Only the Committee and the Division provided some preliminary comments and issues.

The group discussed the need for the performance standards, which are currently voluntary in nature, to be kept in place until the Commission orders otherwise. The group asked PacifiCorp to provide Oregon's standards for group review. On August 22, 2005, PacifiCorp met with the Division and discussed Oregon's Service Quality measures.

On August 29, 2005, the third meeting was held in which the restoration response measures, network improvements, Oregon's standards and the industry definition for Major Events were discussed. Questions about PacifiCorp's restoration process were raised.

On October 14, 2005, PacifiCorp presented a thorough review of Company and industry best practices for vegetation management.

On November 2, 2005, the group discussed the basics of inspection and maintenance of the T&D networks and then went for a field trip in which participants were shown how the inspection and maintenance operations are executed.

On January 9, 2006, the group reviewed (via conference call) the Company's semi-annual report and identified improvements to format and content that would be helpful to the audience.

On January 12, 2006, the group discussed the status of the Task Force.

The group last met on February 22, 2006 and reviewed the appropriateness of the service quality standards, discussed why various parties perceived that neighboring municipalities performed better during the 2003 Holiday Storm, the Third Quarter Service Quality Report and discussed whether penalties/rewards associated with the network performance should be adopted.

Based on these seven meetings and responses to several sets of formal and informal data requests, the Task Force presents its report. The report is organized according to the specific tasks assigned to the Task Force by the Commission.

REVIEW OF PACIFICORP'S UTAH SYSTEM PERFORMANCE

PACIFICORP'S SERVICE QUALITY PROGRAM

During the ScottishPower/PacifiCorp merger, ScottishPower committed to a package of service standards to be implemented in the PacifiCorp territory during the five years following completion of the merger transaction. This package consisted of two types of service standards; Performance Standards and Customer Guarantees. The Performance Standards deal with total company improvements and are what the customers can expect in terms of the level of service provided by the Company. The Performance Standards have two components; Network Performance Standards and Customer Service Standards. The Customer Guarantees are the Company's guarantees to its customers regarding the quality of the customer's interaction with the Company. Setting these standards was motivated by ScottishPower's recognition that system performance and customer service are key determinants of service quality for electric service to satisfy the needs of its customers. As an indication of how committed the Company was to these commitments, the Company offered to pay penalties if it does not fulfill its commitments. The service standards the Company committed to were clearly outlined in Bob Moir's testimony in Docket No. 98-2035-04.

On December 2, 2004, PacifiCorp filed an Advice Filing 04-13 – Docket No. 98-2035-04 proposing some revisions to Electric Service Regulation 25 and Schedule 300 and changes to Network Performance Standard and Customer Service Performance Standards upon the expiration of the Company's five-year merger commitment on March 31, 2005. Specifically, the Company proposed several changes to its customer guarantees, network performance standards, and customer service performance standards and a change in the definition of a Major Event. The Company proposed a three-year term for the modified program with an effective date of April 1, 2005. On March 23, 2005, the Division recommended approval of the program with some modifications. On March 23, 2005 the Commission accepted the changes recommended by the Division except those regarding Customer Guarantee 7. By letter dated April 11, 2005, PacifiCorp outlined the agreed to modifications. Consequently, by a letter dated April 29, 2005, the Commission approved the modified program.

Performance Standards

Currently, the Company is committed to the following performance standards for the three years ending March 31, 2008. The MEHC acquisition commitments state that no modifications will be made to the guarantees or performance standards prior to March 31, 2008 and after 2011 the Company would have the right to request Commission approval to terminate or modify one or more guarantees or performance standards¹.

Table 1. PacifiCorp Performance Standards

<u>Network Performance Standard 1:</u> Improve System Average Interruption Duration Index (SAIDI)	The Company will improve SAIDI by 6% by March 31, 2008.
<u>Network Performance Standard 2:</u> Improve System Average Interruption Frequency Index (SAIFI)	The Company will improve SAIFI by 6% by March 31, 2008.
<u>Network Performance Standard 3:</u> 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.
<u>Network Performance Standard 4:</u> Supply Restoration	The Company will restore power after an outage due to loss of supply or damage to the distribution system on average to 80% of customers within three hours.
<u>Customer Service Performance Standard 5:</u> 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.
<u>Customer Service Performance Standard 6:</u> Commission Complaint Response/Resolution	The Company will a) respond to at least 95% of non-disconnect Commission complaints within three working days and will b) respond to at least 95% of disconnect Commission complaints within four working hours. The Company will c) resolve 95% of informal Commission

¹ Commitment 45 states that "MEHC and PacifiCorp commit to continue customer service guarantees and performance standards as established in each jurisdiction, provided that MEHC and PacifiCorp reserve the right to request modifications of the guarantees and standards after March 31, 2008, and the right to request termination (as well as modification) of one or more guarantees or standards after 2011. The guarantees and standards will not be eliminated or modified without Commission approval."

	complaints within 30 days (In Utah the Company has agreed to resolve 100% of Commission complaints within 30 days.).
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Customer Guarantees

Currently, the Company is committed to the following Customer Guarantees for three years ending March 31, 2008. The MEHC acquisition commitments state that no modifications will be made to the customer guarantees prior to March 31, 2008 and that after 2011 the Company would have the right to request Commission approval to terminate or modify one or more customer guarantee.

Table 2. PacifiCorp’s Customer Guarantees

<u>Customer Guarantee 1:</u> 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.
<u>Customer Guarantee 2:</u> Appointments	The Company will keep mutually agreed upon appointments which will be scheduled within a two-hour time window
<u>Customer Guarantee 3:</u> Switching 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 are excluded
<u>Customer Guarantee 4:</u> 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.
<u>Customer Guarantee 5:</u> Responding to Bill 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.
<u>Customer Guarantee 6:</u> 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.
<u>Customer Guarantee 7:</u>	The Company will provide the customer

Notifying of Planned Interruptions	with at least two days notice prior to turning off power for planned interruptions.
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Status of the Service Quality Program

The Customer Service Standards and Service Quality Measures are expected to reflect PacifiCorp’s performance to provide customers with reliable power. Power reliability is the degree to which the performance of the elements in a bulk system result in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. There are many indices used for measuring reliability. PacifiCorp reports SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and CPI (Circuit Performance Indicator, a PacifiCorp developed index).

According to the Institute of Electrical and Electronic Engineering (IEEE) Guide for Electric Power Distribution Reliability Indices², SAIDI is an index that indicates the total duration of sustained interruption an average customer experienced during a predefined period of time. That is, SAIDI tells us on the average how long an average customer was without power in a given period of time. Although any time period could be chosen, SAIDI is commonly measured in terms of customer minutes or hours. PacifiCorp measures SAIDI in terms of customer minutes. SAIDI is calculated as the total number of customer interruption durations divided by the total number of customers served in the area. In other words, SAIDI is the total customer minutes or hours lost divided by the number of customers served in the area.

The Customer Minutes Lost is the length of restoration time of a sustained interruption multiplied by the number of customers who experienced a sustained interruption during the reporting period. By focusing on the areas with high population density, PacifiCorp could still meet its SAIDI standard at the state level while the areas with low population densities are suffering with poor service quality. To avoid that, PacifiCorp reports several different measures; first, it reports the SAIDI value on a service district and state level, next it identifies Circuit Performance Indicators (CPI), at a circuit level. The SAIDI value that PacifiCorp

² IEEE P1366-2003 Guide for Electric Power Distribution Reliability Indices, copyrighted May 2004

reports excludes major events and thus captures just the value underlying the normal operations.

The System Average Interruption Frequency Index (SAIFI) indicates the number of times an average customer experiences a sustained outage during a specified time period. SAIFI is calculated by dividing the total number of customers interrupted by the total number of customers in the specific service district. The unit of measurement of this index is the number of sustained customer interruptions. Higher values of SAIFI are associated with lower levels of service quality. PacifiCorp reports this Index for underlying conditions excluding major events on a service district and State level.

The Circuit Performance Indicator (CPI) is a blended weighting of SAIDI, SAIFI, Momentary Average Interruption Frequency Index (MAIFI), and Circuit Lock-outs covering three years. The higher the CPI, the poorer the blended performance the circuit is delivering. The CPI is calculated using the following formula:

$$CPI = (SAIDI * W1 * E1) + (SAIFI * W2 * E2) + (MAIFI * W3 * E3) + (LO * W4 * E4) * Index$$

where

LO = Circuit Lock-Outs (the number of substation circuit breaker Lock-Outs).

W = Weighting factors used to set the degree of importance for each factor.

- W1 = 0.30
- W2 = 0.30
- W3 = 0.20
- W4 = 0.20

E = Equalizing factors used to put each weighed factor within a consistent scale.

- E1 = 0.02900261
- E2 = 2.43902439
- E3 = 0.69930069 * total number of customers on the circuit
- E4 = 5.26315789

Index = indexing factor used to magnify the scale for each CPI.

- Index = 10.64537424

PacifiCorp selects the five worst performing circuits annually for target improvements. The improvements are to be completed within two years of selection. Within five years of selection the average performance must improve by at least 20% (as measured by comparing current performance against baseline performance).

The attached Service Quality Review Report (Appendix 1) shows that during the first half of FY 2006, the Company has performed close to targets. The year to date actual SAIDI and SAIFI values were 138 minutes and 1.4 interruptions, respectively, as compared to the planned SAIDI and SAIFI values of 135 minutes and 1.4 interruptions. Year to date PacifiCorp restored power to 85% of its customers within 3 hours after an outage. The report also shows that the Company achieved its goal or was close to it in relation to the telephone service and response to Commission complaints. During this time, there were thunderstorm, heat and brush fire events which impacted the system's reliability. It is also of note that no major events were filed for review.

The attached Service Quality Report also shows that PacifiCorp has performed very well with its customer guarantees program. Table 3 shows the status of the customer guarantees and the amounts of money paid for the first half of FY 2006, which is compared to FY 2005. This Table shows that the success rate for all customer guarantees was over 99% for the first half of FY 2006.

Table 3. Status of Utah Customer Guarantees.

Guarantee	Description	FYTD 2006				FY 2005			
		Event	Failure	% Success	Paid	Event	Failure	% Success	Paid
CG1	Restoring Supply	1,094,970	4	100	\$350	1,183,013	17	99.9	\$1,950
CG2	Appointments	4,568	15	99.67	\$750	4,909	30	99.4	\$1,500
CG3	Switching on Power	14,023	24	99.83	\$1,200	24,241	79	99.7	\$8,275
CG4	Estimates	2,704	25	99.08	\$1,250	3,348	88	97.4	\$4,400
CG5	Respond to Billing Inquiries	4,969	5	99.90	\$250	5,766	14	99.8	\$700
CG6	Respond to Meter Problems	403	2	99.50	\$100	559	7	98.7	\$350
CG7	Notification of Planned Interruptions	20,527	5	99.98	\$250	18,248	6	99.9	\$300
	Total	1,142,164	80	99.99	\$4,150	1,240,084	241	99.98	\$17,475

MAINTENANCE

T&D Preventative and Corrective Maintenance Programs and Cycles

An asset maintenance policy and carefully drafted maintenance plan are essential elements of utility operations. They allow companies to avoid expensive corrective maintenance, decrease risk to employees and the public, meet applicable regulatory requirements, and may increase system reliability. PacifiCorp's philosophy is to optimize maintenance of assets based on the condition of the assets, the effectiveness of the maintenance, and the impact of the asset performance on reliability. PacifiCorp's maintenance plan has two components: preventive maintenance and corrective maintenance.

Preventative maintenance

The purpose of preventative maintenance is to keep assets in a good working condition, maintain safety requirements, prevent premature failures and achieve the expected asset life cycle. To achieve this, PacifiCorp performs preventative maintenance on its substations and distribution and transmission lines with the goal of inspecting and identifying abnormal conditions and performing appropriate preventative actions upon those facilities.

Substations are inspected on a monthly basis to identify situations that could have an immediate effect on the substation or that could prevent the substation from operating correctly. Furthermore, a security and safety inspection is also performed to ensure the integrity of the perimeter fencing has not been tampered with or violated. The outcome of these inspections is recorded on Company inspection forms where the substation manager reviews any abnormal conditions and prioritizes repair requirements.

The preventative maintenance of the distribution and transmission lines falls in one of three categories: 1) Visual inspection, where the distribution and transmission facilities are visually inspected from a vantage point that will allow reasonable viewing access. The purpose of this inspection is to identify damage or defects to the distribution and transmission lines and other potential hazards and right of way encroachments that may endanger the public or adversely affect the integrity of the electric system. Visual inspections are performed once every two

years for the distribution and sub-transmission lines and once per year for the main transmission grid. 2) Detailed inspections, where inspectors visit and carefully inspect visually each overhead structure and spans between structures. During this inspection, infringements by other utilities, defects, potential hazards, and deterioration of the facilities that need to be corrected in order to maintain safe and reliable service are identified. The detailed inspections are performed once every 8 years for the distribution and sub-transmission lines and once per year for the main transmission grid. 3) Test and treat, in which intrusive tests are performed on the wood poles to determine the strength of the pole, with subsequent application of chemicals or other measures to maximize the lifespan of the pole. Poles are tested and treated once every 16 years.

Any abnormal conditions identified during these inspections are recorded in the Company's Facility Point Inspection (FPI) database where the appropriate Company officials review and prioritize them for corrective action.

Corrective maintenance

The purpose of the corrective maintenance plan is to correct the abnormal conditions in the substations and distribution and transmission systems identified during the inspection process according to the priority codes assigned during the preventative maintenance process. These priorities are priority A and priority B. Priority A is related to those abnormal conditions that have immediate safety or reliability implications. Priority B is for abnormal conditions that do not have immediate safety or reliability implications. The Company targets priority A conditions first. The corrective plan for the substations include repairs to major equipment such as circuit breakers, transformers, relays, regulators, and station battery banks. To identify and track all aspects of substation major equipment, the Company uses the work management module in SAP as a database. The database includes the key characteristics of the equipment, location, maintenance and inspection plans, work performed, and any test or inspection results. Outstanding abnormal conditions remain in the database until corrected. For the distribution and transmission lines, the corrective maintenance plan includes overhead line maintenance, underground line maintenance, line apparatus repairs (including pole replacements) and local transmission repairs. The priority codes assigned during the inspection process are used to

target the most critical conditions that need repair first. Once the condition is corrected, the FPI database is updated to indicate the condition was corrected.

PacifiCorp’s maintenance spending plan and actual spending and the percent of the maintenance work load completed for the post ScottishPower merger period is provided in Appendix 1.

Status of the Maintenance Plan

The Company has adopted a comprehensive maintenance plan that is focused on inspection of distribution and transmission lines, as well as substations. In addition to inspections, preventative maintenance is performed on major substation equipment, and wood poles have a defined plan for testing and treating. The status of this plan³ can be summarized by the following table (Table 4).

Table 4. Year to Date Actual and Planned Total Maintenance Spending

Month	Planned Maintenance Spending	Actual Maintenance Spending	Target Maintenance Work	Percent Completed
4/05	\$1,358,319	\$1,358,319	6%	5%
5/05	\$2,068,674	\$2,068,674	7%	7%
6/05	\$2,066,952	\$2,066,952	7%	9%
7/05	\$1,650,011	\$1,650,011	8%	7%
8/05	\$1,978,113	\$2,252,265	7%	9%
9/05	\$1,969,679	\$2,087,795	5%	10%
Total	\$11,091,748	\$11,484,016	40%	47%

The Table shows that the actual maintenance spending is slightly higher than was planned while the Company completed work that is 7% ahead of plan.

VEGETATION MANAGEMENT

Trees growing into the power line can be a hazard to the public and affect the reliability of the system. Branches growing close to power lines could spark a fire, cause an outage, be climbed by the general public (and result in serious injuries) or could be whipped by wind or weighed

³ Refer to Appendix 1.

down by snow causing power outage to the customers. Because of these concerns, PacifiCorp and other utilities clear trees from power lines.

PacifiCorp regularly prunes and removes trees, using the principles of modern arboriculture, to provide safe and reliable electric service to its customers. According to modern arboriculture, the best tree pruning technique is the lateral or directional pruning. This technique promotes the tree's health and involves removing at natural targets entire branches that are growing toward the power line. It takes advantage of strong points in the tree's disease defense system and other biological factors, such as growth regulators, to route tree growth away from the power line, thereby reducing concerns about trees near power lines.

Generally, under this technique, tree pruning is performed in such a way that when pruning trees under the power line, the limbs growing upward should be cut back to limbs growing away from the power line. Trees that are located to the side of the power line and are growing outwards toward the line (with intrusion into the work threshold) should be cut back to limbs that are growing vertically; thus, pruning back either sideways or downward.

PacifiCorp's vegetation management program consists of distribution clearance, transmission clearance, chemical specifications and customer relations.

Distribution Clearance

The Distribution clearance work includes:

- 1) **Cycle Maintenance:** the cycle work is the most efficient distribution clearance work. It involves systematic clearing of vegetation from the distribution line on scheduled cycles either by feeder or grid map. Maintenance cycles are based on the type of facilities, species of trees and growing seasons. The intent of the cycle program is to obtain clearance that lasts for the duration of the cycle. During maintenance cycles, danger trees and non-landscape trees 6 inches in diameter or less are removed, easily climbable trees are corrected, herbicides are applied on saplings of tall growing species, and tree growth regulators are applied on fast growing tree species. Any branches that have grown within the work thresholds are either pruned or removed to gain the threshold clearance.

- 2) Ticket Maintenance: This is reactive work in response to customer requests. Ticket work is limited to trees that represent an imminent safety or reliability risk. PacifiCorp tries to minimize this type of work because it is time consuming and disrupts the cycle work.
3. Construction work: This involves pruning or removing trees to establish rights-of-way for the new construction of distribution facilities.
4. Outage or emergency work: This work is done to respond to extreme weather events.
5. Interim Maintenance: This work involves systematically correcting, in the interim through the scheduled cycles, fast growing trees that grow into the power lines.

The cycle length for the distribution clearance in Utah is currently three years. PacifiCorp believes that this cycle length is currently the most effective and cost efficient for Utah based on the type of tree inventory and growth cycle. The work is prioritized based on tree conditions, outage, length of time since last work, and whether there is a customer request or complaint.

In Docket No. 04-035-70, The Company and the Petitioners stipulated, among other things, the following Utah Power and Light commitment⁴;

“From and after January 1, 2007, Utah Power agrees that it will be current on its three-year vegetation management cycle consistent with the Company’s adopted standards for its owned overhead distribution lines in Utah. In order to accomplish the three-year cycle, Utah Power agrees that 25% to 41% of the distribution line miles in Utah will be reviewed annually. Utah Power further agrees that it will provide semiannual reports of the status of its compliance with this commitment to all members of the Service Quality Task Force. If any semiannual report for a period after January 1, 2007 demonstrates that Utah Power is not current on its three-year cycle in Utah, Utah Power agrees to become current not later than one year following the date of such report showing that it is not current. Utah Power’s current estimate of the cost for vegetation management

⁴ Docket No. 04-035-70. Stipulation. Paragraph 39, Sub-Paragraph a.

on its distribution systems in Utah through December 31, 2011 is \$68 million. Notwithstanding this estimate, the parties agree that Utah Power’s commitment in this subparagraph is for performance of vegetation management and is not an agreement to expend the estimated amount (or any other amount) of funds. Utah Power’s expenditure of funds for vegetation management shall be in amounts it determines, in its sole discretion, are reasonable and prudent, provided recovery of such expenditures in rates is allowed by the Commission.”

The Company also agreed that the above commitment be effective through December 31, 2011 and that it will not request any modifications of the terms of the commitment through March 31, 2008⁵. The parties also agreed that the Company’s compliance with these commitments be monitored by the Task Force⁶.

Distribution Specifications

Generally, the type of facility and the growth rate of the trees determine distribution clearance. PacifiCorp prunes trees to provide the clearance specifications provided in Table 5. Table 5 shows the trimming thresholds and specifications for slow growing trees, moderate growing trees, and fast growing trees.

Table 5. Distribution Primary Clearance

Type of Trees	Trimming Threshold	Specification
<u>Slow Growing Trees (<1 ft/yr)</u>		
Side Clearance	4 Feet	8 Feet
Under Clearance	6 Feet	10 Feet
Over Clearance	8 Feet	10 Feet
<u>Moderate Growing Trees (<1-3 ft/yr)</u>		
Side Clearance	6 Feet	10 Feet
Under Clearance	8 Feet	12 Feet
Over Clearance	8 Feet	10 Feet
<u>Fast Growing Trees (>3 ft/yr)</u>		
Side Clearance	8 Feet 10 Feet	12 Feet 14 Feet

⁵ Docket No. 04-035-70, Stipulation, Paragraph 39, sub-paragraph c.

⁶ Docket No. 04-035-70, Stipulation, Paragraph 40.

Under Clearance	8 Feet	10 Feet
Over Clearance		

However, since PacifiCorp prunes the branches to the natural targets rather than predetermined clearance limits, the clearance specifications are guidelines to use in obtaining proper clearances. Accurate natural target pruning is the overriding principle in PacifiCorp’s work, and the trees, not the specifications, will dictate appropriate cut locations.

Transmission Clearance

The amount of transmission clearance depends on the voltage of the conductor and the type of transmission facility. PacifiCorp performs right-of-way clearance according to the width specified by the easement or permit. If the easement or the permit does not specify the width, then PacifiCorp follows the right-of-way clearance width shown in Table 6. Table 6 shows the specification clearance for transmission right-of-way for single poles, H frame, and steel towers with different voltage conductors.

Table 6. Transmission Right-of-Way Widths

Facility	Distance from Center	Total Width
46 kV Single pole	25 feet	50 feet
69 kV Single pole	25 feet	50 feet
115 kV Single pole	25 feet	50 feet
138 kV Single pole	25 feet	50 feet
161 kV Single pole	37.5 feet	75 feet
230 kV Single pole	37.5 feet	75 feet
69 kV H frame	50 feet	100 feet
115 kV H frame	50 feet	100 feet
138 kV H frame	50 feet	100 feet
161 kV H frame	62.5 feet	125 feet
230 kV H frame	62.5 feet	125 feet
346 kV Steel frame	75 feet	150 feet
500 kV Steel frame	87.5 feet	175 feet

Under clearance on transmission right-of-way is dependent on the height of the conductor off the ground and whether the portion of the right-of-way is under the line or off to the side. For under clearance, PacifiCorp follows the wire zone – border zone recommendations of Bramble

and Byrnes⁷ for those areas where the line is less than 50 feet above the ground. The wire zone is the area under the conductors and 10 feet to the field side of the outside conductor. In the wire zone, PacifiCorp removes all trees. In the border zone, PacifiCorp removes all trees with mature height of more than 25 feet.

For those areas where the conductors are 50 to 100 feet above the ground, PacifiCorp removes all tree species with a potential mature height that could provide less than 50 ft clearance to the conductor. For those areas where the conductor is more than 100 ft above the ground, tall trees could be allowed as long they do not violate the 50 ft clearance to the conductor. Trees with less than 50 ft clearance should be removed.

The cycle length for the transmission clearance is five to ten years depending on the treatment.

Chemical Specifications

PacifiCorp uses herbicides and tree growth regulators in its vegetation management program. Herbicides are used to prevent sprouting from stumps of deciduous trees and are used on saplings of tall-growing species to reduce future inventories. Tree growth regulators are used to slow the growth of fast growing trees so that they will not interfere with facilities before the next scheduled maintenance cycle.

All chemical applications are performed according to federal, state and local regulations and with proper notifications to the property owners. All chemical applications are reported to PacifiCorp on a weekly basis using the appropriate Company herbicide or tree growth regulator report.

Customer Relations

PacifiCorp or the Contractor notifies the property owners at home or business sites before any tree work begins. The notification takes place in the form of a letter, personal visit or door card at least five days but no more than six weeks, prior to the crew arriving. Any complaints from the customer or property owner are communicated to the Company using a property

⁷ Bramble, W.C., and W.R. Byrnes. 1983. Thirty years of research on development of plant cover on electric transmission right-of-way after maintenance treatments. *Journal of Arboriculture*. 17:38-43.

owner refusal/complaint report. PacifiCorp then contacts the customer within 48 hours of receipt of the report to resolve the issue in a fair and professional way.

PacifiCorp performs public education using door hangers and distributing pamphlets and posters such as "Small Trees for Small Places" and "The Right Tree in the Right Place". Also, vegetation management staff conducts presentations to customers to help them understand why PacifiCorp is doing what they are doing.

RESTORATION RESPONSE

PacifiCorp's outage response activities are described in its Utah Holiday 2003 Storm Inquiry Report (Docket No. 04-035-01). To monitor the effectiveness of PacifiCorp's responses to restore power, PacifiCorp, as the rest of the industry, uses CAIDI (Customer average interruption duration index) as a measure of the Company's responsiveness to an outage. The CAIDI shows the average time required to restore service. CAIDI is calculated by dividing the total sustained customer interruption durations by the total number of customers interrupted. In other words, CAIDI is the total customer minutes lost divided by the number of customers interrupted. Those customers who experienced more than one sustained outage are counted as many times as they were interrupted. PacifiCorp does not report this index (because it is a derivative of the indices it does report). The industry average for CAIDI is 88–100 minutes. PacifiCorp's system wide average is 105 minutes while that of Utah is 100 minutes. Besides CAIDI, PacifiCorp also uses other measures to gauge its responsiveness to all outage events. These measures include: 1) 3 hour restoration percentage. PacifiCorp tracks and reports the percentage of the customers who experienced an outage that were restored within 3 hours of outage notification. PacifiCorp's target is to restore 80% of the affected customers within 3 hours; 2) Call to first restoration. This is an average monthly value for the time from when the Company has been first notified of an outage to when the first customer is restored; and 3) Assign to arrive. This is the time between the assignments of an outage (by dispatch) until the arrival of the employee (at the job site). PacifiCorp's goal for FY 2006 is 45 minutes. Deterioration in any of these measures will result in an increased CAIDI value.

APPROPRIATENESS OF PACIFICORP'S SERVICE QUALITY MEASURES AND STANDARDS

PacifiCorp uses service quality measures and standards to determine the appropriateness of its service quality. It uses network performance measures and standards to determine the appropriateness of its network quality of supply. To determine the appropriateness of the service quality measures and standards, the Task Force reviewed benchmarking results of several entities⁸. These entities included ePerformance, PA Consulting, Florida Power and Light, the IEEE Distribution Reliability Working Group, and PacifiCorp.

ePerformance Benchmark Study for Calendar 2003: Among other things, ePerformance compared Utah's system characteristics and outage metrics with those of the rest of PacifiCorp and peer group (Appendix 2). Regarding the system characteristics, PacifiCorp Utah territory is more urban (40%) than the rest of PacifiCorp territory (approximately 25%), but less urban than the peer group (over 70%). PacifiCorp's Utah territory has a lower number of customers per circuit (714.4) than the rest of PacifiCorp territory (752.4) and the peer group (751.5). This means that if a feeder is out, fewer customers will experience an outage in Utah than in the rest of PacifiCorp territory or the peer group. The results show that Utah performs better than the rest of PacifiCorp territory in terms of overhead/underground outages per circuit and per 1,000 customers. However, Utah performs worse than the rest of PacifiCorp in terms of outages per 100 route miles. In comparison to the peer group, Utah performed worse in terms of outages per circuit, outages per 1,000 customers, and outages per 100 route miles.

Regarding the outage metrics, Utah had higher SAIDI and SAIFI values and lower CAIDI value than the rest of PacifiCorp territory. It had higher SAIDI and SAIFI and CAIDI values than the peer group. This means that in an average year, an average customer in Utah is expected to experience more frequent outages than the rest of PacifiCorp. However, on the average, a Utah outage gets restored faster than the rest of PacifiCorp territory, but slower than the peer group. Finally, in terms of momentary interruptions, Utah had a lower MAIFI value (experienced fewer momentary interruptions) than the rest of PacifiCorp and the peer group.

PA Consulting Calendar 2004 Benchmark Study: The PA Consulting benchmarking results show that PacifiCorp's SAIDI, SAIFI and CAIDI values including and excluding major events

⁸ Refer to Appendix 2.

and planned interruptions and using IEEE guidelines (>5 minutes and 2.5 Beta) fall in the fourth quartile among the survey respondents.

The PA Consulting Benchmarking results show that the values for SAIDI range from 44.13 to 892.95 minutes when major events and planned interruptions are included and from 25.0 to 258.0 minutes when major events and planned interruptions are excluded. The values for SAIFI range from 0.64 to 5.4 interruptions when major events and planned interruptions are included and from 0.599 to 2.101 interruptions when major events and planned interruptions are excluded. The values for CAIDI range from 20.76 to 595.7 minutes when major events and planned interruptions are included and from 41.83 to 233.0 minutes when major events and planned interruptions are excluded. While these results are very broad, they are routinely considered in the context of a variety of other measures assembled in the benchmark study, including costs to deliver energy and ratebase per customer

PacifiCorp's SAIDI, SAIFI and CAIDI values including and excluding major events and planned interruptions are 322.4 and 193.6, 2.29 and 1.77, and 104.7 and 107.5, respectively. This indicates that regardless of whether the major events and planned interruptions are included or excluded, the SAIDI, SAIFI and CAIDI values hover between the third and fourth quartile among the survey respondents.

FPL Benchmark Results for Calendar 2004: Another benchmark study the Company participates in is conducted by Florida Power & Light. For results delivered during calendar 2004, reliability results including major events ranged as follows: SAIDI from 11.5 to 4684.4 minutes, SAIFI from 0.11 to 3.64 interruptions and CAIDI from 67.2 to 1301.2 minutes. When major events were excluded, SAIDI ranged from 11.1 to 281.0 minutes, SAIFI from 0.11 to 2.08 interruptions and CAIDI from 44.8 to 217.0 minutes. PacifiCorp reported SAIDI, SAIFI and CAIDI excluding major events 316.8 minutes, 2.13 interruptions and 140.2 minutes, respectively. If major events are excluded, PacifiCorp reported SAIDI, SAIFI and CAIDI of 202.3 minutes, 1.88 interruptions and 107.6 minutes, respectively. Again, these results range between the third and fourth quartile of performance for the companies represented on the panel.

IEEE Working Group on System Design: The IEEE working group on system design conducted a number of surveys on distribution reliability indices. The last survey was completed in 2004. In this survey, 78 companies responded, of which 56 provided detailed information. In this survey fewer differences exist between the data sets provided by each individual company since a consistent method of classifying major event days is used (adopted in IEEE P1366-2003). In order to ensure this consistency is reflected in the comparison only the results for SAIDI IEEE, SAIFI IEEE and CAIDI IEEE are considered. The results of that survey, reported in Appendix 2, show that the SAIDI and SAIFI values of PacifiCorp as compared to all of the respondents rank in the lower (higher reliability) end of the fourth quartile. However, the CAIDI value ranks midway within the third quartile. This indicates that Utahans will experience longer and more frequent outages than the majority of the respondents.

INDICES USAGE BY STATE AND UTILITY

The group has reviewed the results of a survey conducted by PacifiCorp to determine the percent usage of different performance matrices by state. The intent of this review was to determine if there are other measures that if tracked by PacifiCorp could provide us with useful information. In this survey, all US states except those that are served by PacifiCorp were asked whether or not they are using the indices listed in Figure 1. Of the 45 states that were interviewed 38 responded of which 12 do not have any standards in place. Figure 1 shows the percentage of responding states with standards using a given index.

Figure 1. Percent of States Using a given Index

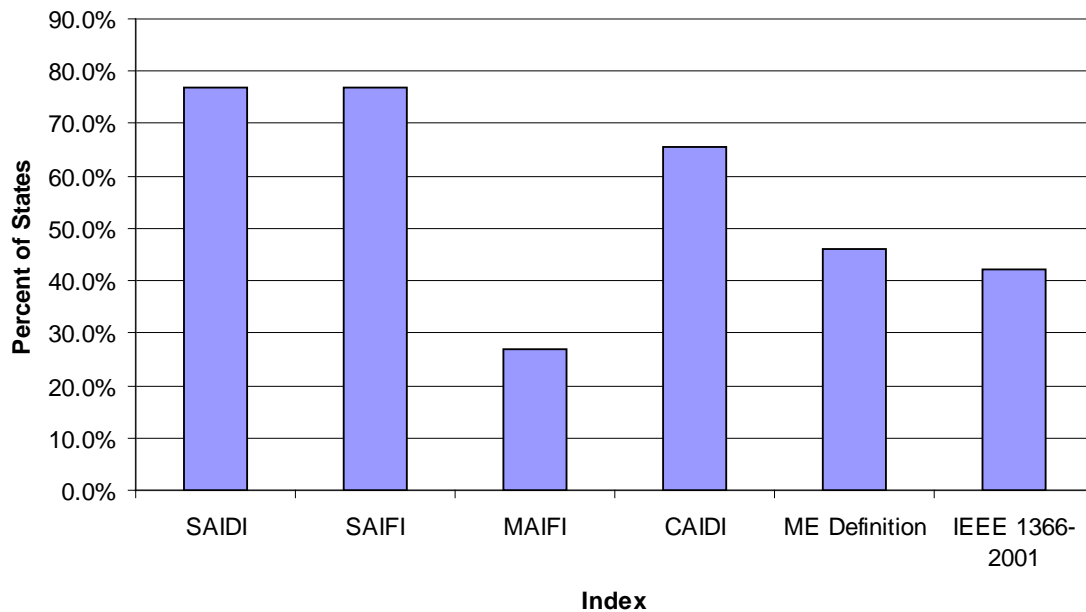
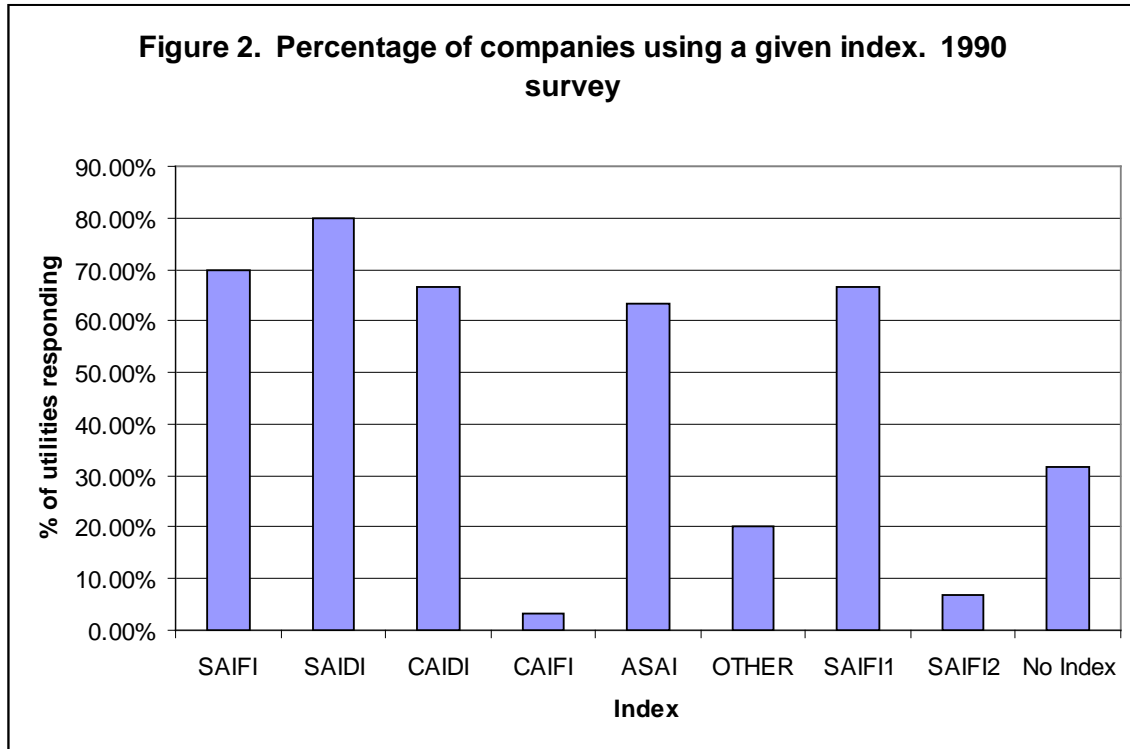


Figure 1 shows that the most commonly used indices by the responding states with standards are SAIDI, SAIFI, and CAIDI. Of the states that responded, 42.3% are using IEEE 1366-2001 guideline (>5 minutes and 10% customers out of service) and 46.2% do have some kind of major event definition.

IEEE also conducted three surveys on distribution reliability index usage. These surveys were completed in 1990, 1995, and 1997. In 1990, 100 utilities were surveyed, 49 of which responded. In 1995, 209 utilities were surveyed, 64 of which responded. In 1997, 159 utilities were surveyed and 61 responded. The results of these surveys are reported in Figure 2. The results indicate that the most commonly used indices by the utilities are SAIDI, SAIFI, CAIDI and ASAI. The Average Service Availability Index (ASAI) indicates the percentage of time that a customer receives power during the reporting period.

Of these commonly used indices, PacifiCorp reports only SAIDI and SAIFI and uses the IEEE 1366-2003 Guide. It does not report CAIDI and ASAI due to the fact they can be numerically derived from the data currently provided in the Company reports. Because of the fact that ASAI is just the flip side of SAIDI expressed as a percentage, it will not provide us with additional useful information that could help us gain better understanding about the system

performance. CAIDI represents the average time required to restore power and is directly a derivative of SAIDI divided by SAIFI. In the future the group thinks that the Company should explicitly report it.



USEFULNESS OF THE BENCHMARKING

The major problem with the reliability metrics is the difficulty of comparing them from one geographic area to another. Differences in how the input data was developed create challenges in simple calculations. In addition, there are concerns about how to normalize the indices for adverse weather. Many state public utility commissions require utilities to compute and track certain reliability indices, but comparing them from region to region and utility to utility has been problematic due to differences in how the data is applied, system designs, weather differences, and even differences in vegetation growth.

There are a number of different sources of disparity between utility practices that make it difficult to compare reliability indices between utilities. Some of the most common sources are

discussed below. It is not the group's intention to develop an exhaustive list of sources of disparities between utilities.

Many companies may have automated outage management systems which will yield highly precise outage measures; others may have automated reporting systems which derive data only for those outages entered. How companies derive fundamental outage data will yield highly diverse results in outage indices.

When performing step restoration after a large scale outage, utilities need to accurately track the start and end time of each step. Failure to do so will result in increased or decreased customer minutes lost which will have a major impact on the value of the indices (SAIDI, SAIFI, and CAIDI).

When analyzing an interruption, utilities vary in how far down the system they go, distribution substation, circuit breaker, recloser, sectionalizer, fuse, transformer, service drop down, or meter. The values of the calculated indices (SAIDI, SAIFI, and CAIDI) will definitely change depending on how far down the system the utility takes its interruption analysis.

Utilities vary in how they define sustained and momentary outages. For sustained outages, the definitions range from an outage that lasts ≥ 1 minute to one that lasts ≥ 5 minutes. For momentary outages, the definitions range from an outage that lasts < 1 minute to one that lasts < 5 minutes. This makes it difficult to meaningfully compare the performance indices (SAIDI, SAIFI and CAIDI). In addition, obtaining accurate momentary information is sometimes difficult because some reclosers and distribution breakers are not equipped with Supervisory Control and Data Acquisition (SCADA).

According to IEEE standard 1366-2001, utilities are allowed to exclude major events when calculating their indices. However, there is a wide variance in how utilities define a major event. There have been substantial differences between IEEE standards 1366-1997, 2001 and 2003. This has a serious impact on the value of the indices as they are compared across time unless great effort to equilibrate the measures is undertaken.

From the above discussion, it is clear that the process used for calculating reliability indices can vary greatly from utility to utility. The input data sources vary tremendously, and there are

major differences in basic calculation methods. The indices present challenges for comparing utility performance unless these discrepancies are identified and understood. Even then, it may not be possible to make the indices for different utilities numerically comparable. However, the development of more comparable benchmarking methods should not be ruled out now that the Task Force has been given an overview in this area.

ADEQUACY OF CUSTOMER GUARANTEES

In May 2004 the Company completed a survey of US utilities offering customer guarantees by reviewing Edison Electric Institute's roster of investor-owned electric utilities, identifying which utilities had customer guarantees in place and obtaining customer guarantee information through each company's web site. With the customer guarantee information obtained from the various web sites the Company compiled a comparison summary of utility customer guarantees, a copy of which is in Appendix 1.

As reported, 13 utilities (including PacifiCorp) were identified as offering guarantees. These 13 utilities offered, on average guarantees in five areas, with an average failure payment of \$23. All but one offered a guarantee for appointments. Only two utilities besides PacifiCorp have a guarantee for restoration of service and both of these include an exemption for "major events" as shown in the footnote of the survey summary. No utilities besides PacifiCorp offer a guarantee for reconnection of service applicable to customers who have not paid for service. PacifiCorp is also the only utility offering a guarantee on estimates for providing new supply.

Overall, the summary shows that PacifiCorp provides more guarantees than the rest of the companies that provide some level of customer guarantees. Also, it pays larger credit amounts for most of the guaranteed services in case it fails to provide the guaranteed level.

ON-GOING INVESTMENT AND MAINTENANCE PLAN

PacifiCorp's maintenance and investment plans were discussed earlier in this report. The objective of this section is to determine whether PacifiCorp is on track to meet its transmission and distribution maintenance targets and to determine if these targets are appropriate. A comparison of the actual and planned work loads and budgets indicate that the Company is on track to meet its investment and maintenance targets (Appendix 1).

Regarding the appropriateness of the maintenance targets, the group analyzed PacifiCorp's inspection program. A summary of the inspection program results is presented in Table 7. Table 7 shows the number of priority A and B conditions in FYs 2002 through 2005 excluding telecommunications clearance conditions. All clearance or abnormal conditions identified during the inspection cycle that are the responsibility of communications companies are assigned to them for correction.

Table 7. Priority A and B conditions found, cleared and outstanding

Fiscal Year	PAC Priority A Conditions			PAC Priority B conditions		
	Found	Cleared	Outstanding	Found	Cleared	Outstanding
2002	2782	1931	1095	7966	4224	5078
2003	2396	2241	601	6722	4978	3383
2004	3802	3224	1244	10319	7409	4747
2005	4861	4662	1130	12105	10061	5344

The priority A or B outstanding conditions for a given fiscal year is calculated as the sum of the number of outstanding priority A or B conditions for the prior year and the number of priority A or B conditions found in the given year less the number of facility points with outstanding conditions removed in the given year and the number of facility points with outstanding priority A or B moved in the given year. For example, for FY 2003,

FY 2003 year-end outstanding (A or B) conditions =

- FY 2002 year-end outstanding (A or B) conditions
- + FY 2003 (A or B) found conditions
- FY 2003 (A or B) corrected conditions
- FY 2003 (A or B) removed facility points with outstanding conditions
- FY 2003 (A or B) moved facility points with outstanding conditions.

Throughout any given year, facility points are added and removed. It is possible that some of these facility points exist in the FPI database, but they are not physically located in the field. If this occurs, and these facility points had outstanding conditions, then these outstanding conditions are not shown as cleared in the FPI database until the data entry or clean-up is completed. Similarly, facility points can be moved for activities such as highway relocations or public accommodations. If these moved facility points had outstanding conditions, then these outstanding conditions are not shown as cleared in the FPI database until data clean up is completed.

A facility point is an electrical point of interest to PacifiCorp which is part of the electrical, physical plant system. The FPI system contains both overhead and underground plant. The Company's inspection program is more heavily focused toward the overhead system, largely comprised of poles and accompanying equipment, and includes both distribution and transmission facilities.

Paperwork flow can impact accounting-like true-ups between the end-of-year outstanding conditions for two consecutive years. After outstanding conditions are physically corrected in the field, paperwork is then provided to the data entry personnel to complete the process. Paperwork that has not yet been processed when a new report is run can also affect the outstanding conditions report.

Because the FPI database has certain software limitations for extracting data, PacifiCorp is not able to determine removed facilities, moved facilities or paperwork lag database corrections. Therefore, PacifiCorp must depend on the results of a report run on a specific date to show the year-end outstanding conditions.

The existence of end of year outstanding priority A or B conditions does not constitute a National Electric Safety Code (NESC) violation. Defects in the system normally occur as a result of things like normal wear and tear, aging, acts of third parties and acts of nature. Utilities are required to construct their facilities according to NESC standards and to identify and repair those conditions that they are responsible for in a systematic, reliable and documented manner. Failure to do so without any mitigating factors may constitute a NESC violation.

Under its maintenance procedures, PacifiCorp tracks, by state, its outstanding defects and/or abnormal conditions found during the regularly scheduled safety inspections, detailed underground facility inspections, detailed overhead facility inspections, and detailed test and treat overhead facility inspections. PacifiCorp's field inspectors then designate defects and/or abnormal conditions into condition priorities. Condition priorities are documented. If the defect is determined to be priority A, it may be corrected immediately (if the correction can be completed on the spot without any special safety clearances), within days, or scheduled as planned work on higher priority basis. Corrections of the remaining conditions are then coordinated as part of the Company planning process.

Therefore, since the Company installs its facilities according to the current NESC, inspects its facilities and identifies, documents and repairs conditions within a reasonable period, the Company is following the NESC. From Table 7, there is a sizable volume at the end of year conditions that are not yet decreasing over time. This volume can be attributed to the highly organized inspection program that was initiated in 2002. However, in Docket No. 04-035-70, the Company and the Petitioners stipulated, among other things, the following Utah Power and light commitment⁹;

“From and after July 1, 2007, Utah Power agrees that it will repair or correct all priority “A” conditions identified on its Utah distribution system that it is responsible to repair or correct within 120 days on average of the date the condition was identified. Priority “A” conditions are conditions such as leaking electrical equipment, burning electrical connections, broken insulators, trees in primary conductors, unsecured primary conductors and broken guy wires. Utah Power further agrees that it will provide semiannual reports of the status of its compliance with this commitment to all members of the Service Quality Task Force. If any semiannual report for a period after July 1, 2007 demonstrates that Utah Power is not in compliance with this commitment, Utah Power agrees to become compliant with this commitment within six months following the date of the report showing that it is not in compliance. Utah Power's current estimate of the cost to inspect and maintain its distribution system in Utah in compliance with

this commitment through December 31, 2011 is \$111 million. Notwithstanding this estimate, the parties agree that Utah Power's commitment in this subparagraph is for performance of repair or correction of priority "A" conditions within 120 days of the date they are identified on average and is not an agreement to expend the estimated amount (or any other amount) of funds. Utah Power's expenditure of funds for inspection and maintenance of its distribution system in Utah shall be in amounts it determines, in its sole discretion, are reasonable and prudent, provided recovery of such expenditures in rates is allowed by the Commission."

The Company also agreed that the above commitment be effective through December 31, 2011 and that it will not request any modifications of the terms of the commitment through March 31, 2008¹⁰. The parties also agreed that the Company's compliance with these commitments be monitored by the Task Force¹¹.

In Figure 4.6-11 of WCI's Review of PacifiCorp's Storm Response report, Utah Power's distribution maintenance spending per customer and per MWh are \$22.78 and \$996.7. Both of these figures are in the first quartile (low cost), well below the mean.

Since the number of outstanding NESC conditions is relatively high and the maintenance spending per customer is relatively low, the Task Force began to look into the costs and benefits associated with accelerating the correction of the NESC outstanding conditions to a correction rate faster than currently achieved by PacifiCorp. A discussion of this benefit cost analysis is in the section "Possible Improvements to the System" of this report.

POSSIBLE IMPROVEMENTS TO THE SYSTEM

To identify possible improvements to the system, the group looked into the rationale behind PacifiCorp's commitments to improve the network performance by improving state SAIDI and SAIFI by 6% over three years (2% annual improvement) and reducing by 20% the Circuit

⁹ Docket No. 04-035-70, Stipulation, Paragraph 39, sub-paragraph b.

¹⁰ Docket No. 04-035-70, Stipulation, Paragraph 39, sub-paragraph c.

¹¹ Docket No. 04-035-70, Stipulation, Paragraph 40.

Performance Indicator (CPI) for a maximum of five under performing circuits on an annual basis within five years after selection. The Task Force also looked into the costs and benefits associated with improving the SAIDI and SAIFI by more than 2%.

The selection of 2% annual reliability improvement or 6% over three years (FY 2006 – FY 2008), was an extension of the prior commitment established during the ScottishPower/PacifiCorp merger. It is exclusively based on Company experience and not on benefit/cost analysis. The Company's experience indicated that 2% annual improvement has been a challenging, but achievable, target in improving reliability, particularly considering the continued anticipated growth in the Utah service area.

Based on the above discussion, PacifiCorp looked at the benefit/cost analysis of improving the SAIDI and SAFI by more than 2% annually. The Company analysis estimates that improving reliability by 1.1%, 2%, 3.5% and 4.3% annually would cost approximately \$2.1, \$3.7, \$6.5 and \$8.3 million dollars incrementally per year, respectively. These costs are the Company costs of improving reliability.

To determine the benefits associated with improving reliability, the Company used a value for outage approach developed by the Electric Power Research Institute (EPRI) in the mid 1990s. This approach was updated with a peer company that established the customer value for an outage based upon the customer class, the time of year, the day of the week and the duration of the outage. The approach also balances the willingness to pay for improved reliability to ensure that artificially high values were not being developed. These are the values of reliability to the customer. The results of the annual costs and values of improved reliability over 10 years for the State of Utah are reported in Table 8.

Table 8. PacifiCorp Value for Outage Projections of Improved Reliability for the State of Utah

Year	Improvement							
	1.1%		2%		3.5%		4.3%	
	Cost	Value	Cost	Value	Cost	Value	Cost	Value
1	\$2,100,000	\$2,052,029	\$3,700,000	\$3,730,962	\$6,500,000	\$6,529,183	\$8,300,000	\$8,021,568
2	\$2,100,000	\$2,029,457	\$3,700,000	\$3,656,342	\$6,500,000	\$6,300,662	\$8,300,000	\$7,676,640
3	\$2,100,000	\$2,007,133	\$3,700,000	\$3,583,216	\$6,500,000	\$6,080,138	\$8,300,000	\$7,346,545
4	\$2,100,000	\$1,985,054	\$3,700,000	\$3,511,551	\$6,500,000	\$5,867,334	\$8,300,000	\$7,030,643
5	\$2,100,000	\$1,963,219	\$3,700,000	\$3,441,320	\$6,500,000	\$5,661,977	\$8,300,000	\$6,728,326
6	\$2,100,000	\$1,741,623	\$3,700,000	\$3,372,494	\$6,500,000	\$5,463,808	\$8,300,000	\$6,439,008
7	\$2,100,000	\$1,920,265	\$3,700,000	\$3,305,044	\$6,500,000	\$5,272,574	\$8,300,000	\$6,162,130
8	\$2,100,000	\$1,899,142	\$3,700,000	\$3,238,943	\$6,500,000	\$5,088,034	\$8,300,000	\$5,897,159
9	\$2,100,000	\$1,878,252	\$3,700,000	\$3,174,164	\$6,500,000	\$4,909,953	\$8,300,000	\$5,643,581
10	\$2,100,000	\$1,857,591	\$3,700,000	\$3,110,681	\$6,500,000	\$4,738,105	\$8,300,000	\$5,390,003

Table 8 shows that the costs associated with achieving and maintaining a certain level of annual improvement is fixed. However, the value associated with that level of reliability improvement decreases over time. The value declines faster as the associated level of reliability improvement gets higher, making it uneconomical to continually increase the target for reliability improvement. To make the 2% annual reliability improvement economical is apparently challenging as can be seen in Table 8. However, based on its experience, the Company believes that it achievable. Therefore, based on the foregoing discussion, the Task Force believes that the annual 2% reliability improvement that the Company committed to is challenging but appropriate.

In developing the selection of circuits for improvements which lead to the various improvement percentages in Table 8, the Company assumed that only those circuits that have high frequency of outages would be considered. These outages are on both densely and sparsely populated circuits, with a general preference toward those circuits that achieve greater improvement in state-level metrics. This assumption is fundamental to the selection since customers value reliability after they have outages, therefore if a customer has minimal outage experience their value for improved reliability is low and does not support the core value assumptions underlying Table 8.

Therefore, the Task Force does not have any benefit/cost analysis basis to determine whether correcting the outstanding conditions faster is appropriate. However, since an inadequate maintenance practice may result in decreased reliability and this is being addressed, the Task Force believes that it is appropriate to closely monitor the network performance measures and

standards. The network performance measures and standards can provide us with clear indication of system integrity and performance.

Based on the foregoing discussion and the problems mentioned with reliability indices benchmarks and comparisons are not reliable and are not meaningful, the Task Force does not have any specific recommendations regarding possible improvements to the system except with respect to the continued improvement in SAIDI and SAIFI and that it be a subject for continued review and study, in anticipation of making recommendations for standards, if any, to be in effect on or after March 31, 2008.

BENEFIT/COST ANALYSIS OF INCREASING THE DESIGN AND OPERATIONAL LIMITS OF THE DISTRIBUTION NETWORK

It was claimed during the 2003 Holiday outage investigation that neighboring municipalities fared better than PacifiCorp. These claims prompted some parties to ask what programs these municipalities have that PacifiCorp does not have that allowed these municipalities to restore power faster than PacifiCorp and what would be the costs and benefits associated with having these programs implemented in PacifiCorp's Utah territory?

A full description of the storm and its impacts can be found in the PacifiCorp's Utah Holiday Storm Inquiry – 2003. In this report we will compare PacifiCorp's performance during the events from December 26, 2003 to January 2, 2004 with that of the neighboring municipalities. In researching events experienced by the neighboring municipalities, PacifiCorp interviewed the management personnel for the cities of Kaysville, Bountiful, and Murray, Utah. PacifiCorp's territory and these municipalities differed in geography, pattern of affected area, specifics of the weather (ice, heavy snow, wind, light snow), and actual type of damage. This makes it difficult to make an effective comparison. However, an in-depth analysis of the affected areas has shown that Centerville (PacifiCorp territory) and Bountiful (a municipality) have more similarities than any other adjacent PacifiCorp and municipal territories. A comparison of the performance of Centerville and Bountiful provides more of an "apples-to-apples" comparison. Tables 9 and 10 compare the two areas.

Table 9. A comparison of Centerville and Bountiful.

Item	Centerville	Bountiful
Population	14,748	41,401
Service Territory sq miles	6 sq miles	10 sq miles
# of Customers in impacted area	5,187	15,700
Snow accumulation	+40 inches	+40 inches
# Customers with underground service	3,584	6,280
% of customers with underground service	69.10%	40%
Peak # of customers out	2,462	1,300
% of customers restored w/in 24 hrs	99.70%	99.70%
# of substations	2	5
# of substations source out	0	0
# distribution feeders	5	18
# distribution feeders locked out	1	2
Line miles overhead wire	29 miles	98 miles
Line miles overhead secondary/service wire	62 miles	136 miles
Line miles UG primary wire	49 miles	87 miles
Line miles UG secondary	36 miles	22 miles

Table 9 shows that the snow accumulation in both areas was over 40 inches. The accumulation was more on the eastern benches where most of the service is underground than the western benches (Figure 4). In both areas 99.7% of the affected customers were restored within 24 hours.

There are 2 substations and 5 distribution feeders serving 5,187 customers in Centerville and 5 substations and 18 distributions feeders serving 15,700 customers in Bountiful. Since the number of customers in Bountiful is about three times that of Centerville, if you triple the number of customers in Centerville you would need approximately 5 substations and 18 distribution feeders. This shows that two systems have similar numbers of customers per feeder. Besides, both systems are designed using the NESC publication for the year of installation.

Figure 4. Snow accumulation during the 2003 Holiday outage

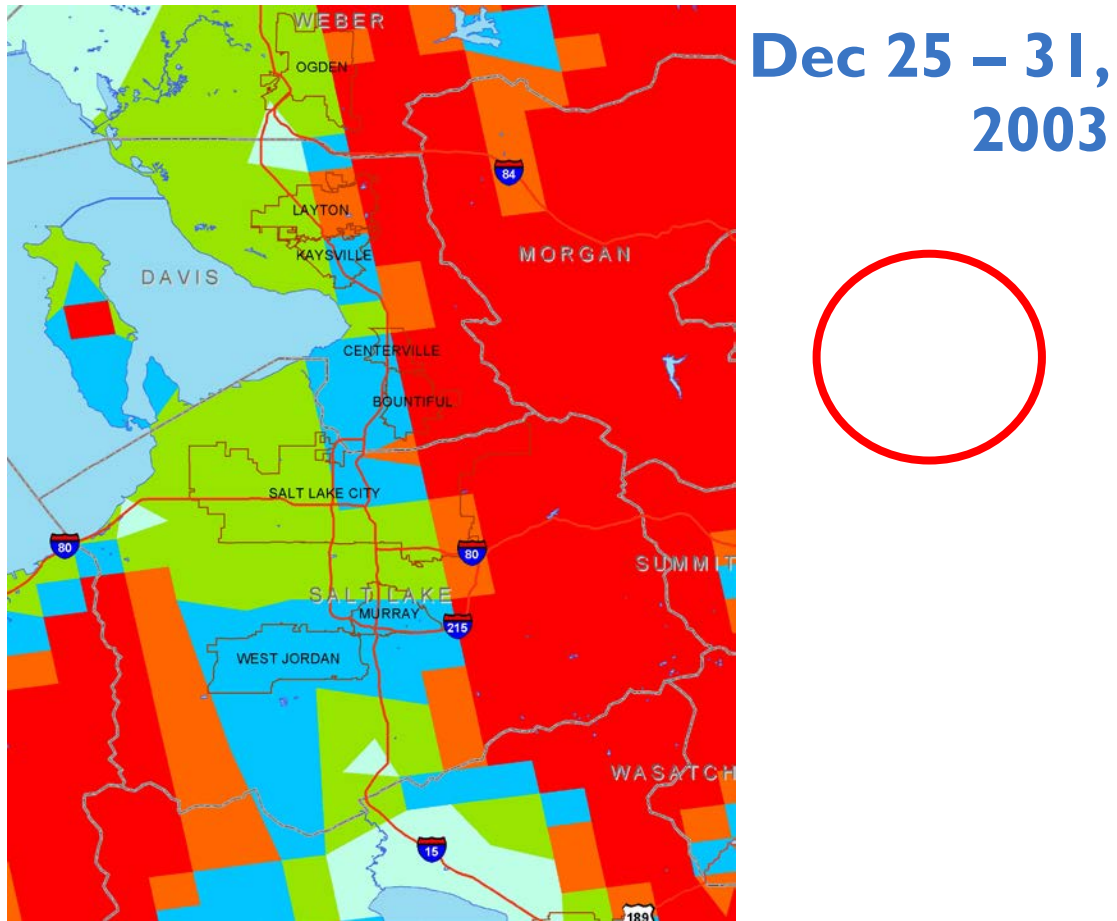


Table 10. Similarities and differences between Centerville and Bountiful

Item	Similar	Comments
Customer call center		
Incoming telephone lines	YES	~1:2000 cust
IVR	YES	
Line personnel	YES	
3 man crews		
3 man tree crew		
Dispatchers		
Substation/ Generation Technician		
4 man contract crew		Budget dependent
Emergency response plans	YES	
Electric service		
Company responsibility	YES	Stop at weatherhead Meter base, riser, weatherhead
Customer responsibility	YES	
Vegetation management		
OH primary wire clearance	YES	10 feet
OH secondary wire clearance	NO	1-3 ft vs 10 feet
OH service wire clearance	NO	1 ft vs 2-10 ft

Planned trimming cycle	YES	3 year
Program – encouraged customers to allow removal of trees	YES	
Tree replacement program	YES	
Tree density		
Maintenance Activity		
Distribution lines	YES	
Substations	YES	

Table 12 shows other similarities between the two systems. Both systems use customer call centers with incoming call line capacity of 2000 customers per line. Both utilities also use Interactive Voice Response (IVR). In addition both utilities maintain their systems as noted within the NESC publication, and their responsibilities end at the weatherhead.

Regarding vegetation management, both utilities have an overhead primary wire clearance of 10 ft, a planned tree pruning cycle of 3 years, a tree replacement program and encourage customers to allow removal of trees. The two utilities differ in their overhead secondary wire and service wire clearances. The overhead secondary wire clearances are 1-3 ft for Centerville and 10 ft for Bountiful. The overhead service wire clearance is 1 ft for Centerville and 2-10 ft for Bountiful. However, Bountiful personnel have indicated that while they prefer 10 feet clearance the service wire, they are not always able to achieve this clearance because the customer requests minimal pruning.

While there are few differences between Bountiful’s and the Company’s vegetation management practices, no meaningful conclusions about how each overhead system performed could be reached. This is primarily due to the fact that Bountiful obtained its maximum snow-depth in areas served by its underground system, while the Company experienced comparable snowfall on its overhead system. In addition, the Company is unable to make comparisons of industry reliability metrics between Bountiful and itself since Bountiful does not capture or calculate these metrics. In general, anecdotal evidence indicates that Bountiful and Centerville experienced very similar outages and restoration conditions during the storm.

Based on the foregoing, the Task Force concluded that the two areas have similar design, communication programs, vegetation management programs, maintenance programs and that both restored 99.7% of the customers that experienced outages within 24 hours.

MAJOR EVENT DEFINITION

The Task Force agrees that the definition of a major event is consistent for both customer guarantees and network performance standards, but didn't address application of exceptions, including the major event exception, to customer guarantee payments.

RECOMMENDATION

Based on the information and analyses described in this report, the members of the Service Quality Review Group believe that the Task Force has completed the specific tasks assigned to it by the Commission. Furthermore, PacifiCorp has agreed to provide the Division and the Committee with a quarterly Service Quality Review Report, the content of which has been approved by the Task Force. The Company has also agreed to meet quarterly with the Division and other interested parties to discuss the report and respond to any concerns that may arise. The Task Force members agree that the information contained in this report will allow the Division and other interested parties to monitor PacifiCorp's Utah distribution operation and maintenance expense expenditures and to track the Company's performance with respect to its service quality and reliability commitments. With the Service Quality Review Report and a quarterly meeting process now in place, the Task Force members recommend that the Task Force's work with respect to Docket Nos. 04-035-01 and 04-035-45 be concluded. However, for purposes of receiving the reports contemplated in Commitment U9 in the MEHC acquisition order, the semiannual reports contemplated in the Stipulation in Docket No. 04-035-70 and the quarterly reports specified above, the Task Force members recommend that the Task Force continue to monitor the reports. If members of the Task Force conclude that Task Force meetings should resume based on the content of reports filed by the Company, they will notify the Commission.

The Task Force believes that it is appropriate to closely monitor the network performance measures and standards. The network performance measures and standards can provide us with clear indication regarding system integrity and performance. The Task Force does not have any specific recommendations regarding possible improvements to the system except with respect to continued review of the system performance in anticipation of making recommendations, if any, to be in effect on and after March 31, 2008.

Finally, the Task Force should file an annual report of its efforts, concerns and recommendations with the Commission.