State of Utah
Department of Commerce
Division of Public Utilities

KLARE BACHMAN
Executive Director

JASON PERRY
Deputy Director

IRENE REES
Director, Division of Public Utilities

OLENE S. WALKER
Governor

GAYLE F. McKEACHNIE
Lieutenant Governor

MEMORANDUM

To: Public Service Commission of Utah

From: Division of Public Utilities
Irene Rees, Director
Energy Section
Artie Powell, Acting Manager
Abdinasir Abdulle, Technical Consultant

Date: September 21, 2004

Re: Docket No. 02-2035-02, and 04-035-01 PacifiCorp's claims to exclude outages attributable to events seven, eight, nine, and ten

---

ISSUE

PacifiCorp has filed major event claims for the events that took place during August 14 through 15, 2003 (event 7), August 21 through 23, 2003 (event 8), in October 30 through November 4, 2003 (event 9), and December 26, 2003 through January 3, 2004. Events 7 and 8 were filed on September 24, 2003, Event 9 was filed on December 4, 2003, and Event 10 was filed on May 19, 2004. In these filings, PacifiCorp requested designation of these events as major events for exclusion from network performance reporting on the basis that these events exceeded the design or operational limits of the system, resulting in damage to the power system and causing sustained interruptions to more than 10% of customers in the affected operating areas.

RECOMMENDATIONS

The Division recommends that the Commission approve PacifiCorp's request to designate Events 7, 8, 9, and 10 as major events and exclude them from the network performance reporting. After closely reviewing PacifiCorp's claims, the Division found that event 7 exceeded operational limits and caused 10% of the customers in the affected operating areas to experience a sustained outage. Regarding Events 8, 9, and 10 the Division found that the design and operational limits were exceeded and that more than 10% of the customers in the affected operating areas experienced a sustained outage. However, the Division recommends that the Major Event report attached to the Company's filing of Event 10 be replaced with the Major Event report attached to this memorandum. The reason for this recommendation is discussed below.

DISCUSSION

The Company's reliability predictors are measured in terms of number and duration of disruptions of service. Extreme events outside the Company's control are excluded from the reliability measures to ensure that extraordinary storms or occurrences do not skew the numbers.

Claims for exclusion generally refer back to Merger Condition 31. Merger Condition 31 is outlined in a stipulated agreement between the Company, the Division of Public Utilities and the Committee of Consumer Services and incorporated into the Commission's 1999 order approving Scottish Power's merger with PacifiCorp. Merger Condition 31 states:

> *Subject to the following reporting and dispute resolution provisions, PacifiCorp may use the IEEE criteria to determine what constitutes an "extreme event" as proposed in the Direct Testimony of ScottishPower witness Moir. The claim by PacifiCorp may involve judgments regarding design limits of or extensive damage to the power system. If*

so, PacifiCorp will file with the DPU a report specifying the basis for the claim and any disputes regarding the merits of the claim will be resolved by the Commission.

The parties to the stipulation agreed that certain “extreme events” would be excluded from performance measures. Anticipating that claims for exclusion would involve “judgments regarding design limits of or extensive damage to the power system,” Merger Condition 31 requires the Company to file any claim for exclusion with the DPU along with a report justifying its claim. The DPU investigates the claim and refers the matter to the Commission for final action.

Over time, Company representatives and DPU staff clarified the definition of “major event” by adopting the IEEE standard. In a letter to the Division dated October 23, 2002, the Company proposed the IEEE definition as follows:

A major event is an event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period.

The IEEE standard is the working definition against which the Division evaluates claims for exclusion pursuant to Merger Condition 31. Each claim for exclusion is accompanied by documentation to support the Company’s assertion that an event exceeded operational or design limits and otherwise met the IEEE major event criteria.

The circumstances of event 10 raised issues about Customer Guarantee 1, which also provides exclusions for “major events.” Therefore, it is helpful to differentiate between the two exclusions.

Customer service guarantees are separately addressed in the stipulated agreement in Attachment 1. Paragraph C. 1. states:

a. Guarantee. If the customer loses electricity supply because of a fault in PacifiCorp's system, PacifiCorp will restore the customer's supply as soon as possible.

b. Penalty. If power is not restored in 24 hours, customers can claim \$50 for residential customers and \$100 for commercial and industrial customers. For each extra period of 12 hours the customer's supply has not been activated, the customer can claim \$25.

Two features of this language are worth noting. First, the guarantee applies if the supply is interrupted "because of a fault in PacifiCorp's system," perhaps suggesting that the stipulating parties intended a guarantee only against system defects or negligence on the Company's part. Second, payment is not automatic. Affected customers must file claims for compensation.

The customer service guarantees made their way into Electric Service Regulation No. 25 of the tariff with changes to the language. Customer Guarantee 1 of Regulation No. 25 excuses the Company from customer guarantee payouts in the event of:

(6) Major events, such as storms.

(7) Instances where resources required to meet the guarantees were re-deployed to restore supplies during a major event in another operating are or utility.

. . .

(9) Causes related to force majeure, which include . . . extraordinary action of the elements, earthquake or other acts of God . . . .

Regulation 25 defines "major storm" as a catastrophic event that exceeds the design limits of the electric power system, *or* causes extensive damage to the electric power system, *or* results in more than 10% of the customers in an operating area to lose power. This definition is different from and, in fact, broader than the definition related to reliability measures (Merger Condition 31). Additionally, Regulation No. 25 requires affected customers to file their claims for credit with the Company. The Company makes the initial determination about claims for credit, subject to dispute resolution processes before the Commission.

Clearly, the standard and process for determining whether the Company can exclude a major event from its reliability index is a separate matter from a determination about payouts under Customer Guarantee 1. Arguably, an occurrence that is deemed a "major event" under Merger Condition 31 also meets the more liberal criteria for "major event" under the Customer Guarantee standards. However, the only issue addressed here is whether events 7, 8, 9 and 10 qualify for exclusion under Merger Condition 31.

Ten Percent Criterion

Determining whether at least 10% of the customers within an operating area experienced a sustainable interruption during a 24-hour period is straightforward. The number of customers in a particular operating area whose electric service was interrupted for at least five minutes is determined and divided by the average customer count in that operating area. This will provide the percentage of customers who were interrupted for a sustained period (sustained customers off). If this percentage is 10% or more, then the requirement that at least 10% of the customers within an operating area experience a sustainable interruption during a 24-hour period is fulfilled, otherwise the requirement is not fulfilled.

Operational Limit

On a regular basis, the Company experiences power outages and restores power. In the event of an outage, the operational manager estimates the number of hours that will be required to fully restore power based on the number of outage incidents stacking up, and the number of resources available in the operational area. The Company targets to restore power within three hours for at least 80% of the customers who experienced power outage. However, when a substantial event occurs that results in numerous outages, the Company tries to restore power within approximately 24 hours. In determining the restoration time, the Company first evaluates the effect of using internal Company resources that are within the operating area experiencing the outage. The internal Company resources are what the Company has available for normal outage restoration in a given operating area. Thereafter the available resource pool is the line staff that can be safely interrupted and moved from other non-restoration activities. The operational manager determines whether the current backlog of outages will take more than 24 hours to fully restore power in an operating area. If it appears that the problem is escalating and that additional resources are required to eliminate the situation, the operational manager and the regional director will discuss, among other things, the scope of the outage (localized and generalized), the required restoration time, and the number of customers affected. If necessary, the Regional Emergency Action Center (REAC) will be activated and outside resources will be called in. The REAC provides a method for securing resources, establishing priorities and managing in an outage event that cannot be reasonably resolved using only the available operating district staff. The outside resources consist of Company crews from other operating areas, contract crews, crews from other Companies that entered into Mutual Assistance Agreement (MAA) with PacifiCorp, as well as crews from other Companies and contracts not accessed via an MAA.

Therefore, for one to determine whether or not the operational limits were exceeded, one needs to determine if the Company used resources in excess the average number of resources needed for normal outage restoration. In any case, once the REAC is activated and outside resources are called in, the operational limits have, by definition, been exceeded.

Design Limit

In general, transmission structures, due to their long slender nature and relatively light point loads, are designed to withstand specific wind-speeds, which is the controlling or limiting condition. Distribution poles, on the other hand, tend to have more point loads along their length. Additionally, their conductor weights, when under ice or other extreme conditions, will create additional stresses, such that these combined loads are those against which the structure must be tested. These parameters are proscribed under the National Electric Safety Code (NESC) by using velocity pressure factors, gust response factors, ice loading conditions and other factors along with wind-speed to establish the proper selection of strength.

It is important that the system be designed with the proper “weak link”. In other words, if failure is imminent (and all designs assume some failure point), failure should be in such a mode that safety is not jeopardized and that property is minimally impacted. As a result, conductors are the weakest link, followed by their attachments (pins, etc.) followed by cross-arms, with poles being the least-favored item to break.

Within the electric delivery system, the transmission system and its components are designed and operated to a higher standard than the distribution system. This would imply that since transmission structures were specified to meet at least 70 mph in Utah, distribution structures would be designed to meet something less than that.

Efforts to Prevent System Damage

The Company adopted a more stringent standard for its eastern system, initiated in the early 90s. The new standard equates to strength sufficient to withstand winds of 117 mph for its transmission structures. On the distribution system, the Company instituted a pole test-and-treat program in 2002. It implemented a 16-year inspection cycle for pole strength and an 8-year cycle for pole safety (conductor clearances, etc.). For those poles with insufficient strength, they are prioritized highly and replaced. For those with sufficient strength, they are treated to extend their useful life. Additionally, the Company has modified its transmission and substation lightning design criteria for new and rebuilt facilities. It is currently modifying its distribution lightning design criteria.

EVENT 7

Event Description

On August 14 through 15, 2003 (Event 7), a thunderstorm with rain and winds with maximum sustained speed of over 35 mph and a peak gusts of over 43 mph moved into Ogden and Tremonton and the surrounding areas causing wide spread damage on the power system that resulted in a sustained outage (more than 5 minutes) for more than 10% of the customers in those operational areas with 3,210,936 customer minutes lost, 175 sustained incidents, and 21,402 sustained customers off. The total cost of the damage was $208,415 of which $21,125 was capital cost and $187,290 was expense.

Ten Percent Criterion

Event 7 affected customers in the Ogden and Tremonton operating areas. The average customer counts in these operating areas were 92,133 customers in Ogden and 7,905 customers in Tremonton. Of this, 20,552 customers (22.3%) in Ogden and 850 customers (10.8%) in Tremonton, experienced with sustained outage. This shows that in both of the operating areas at least 10% of the customers experienced a sustained outage.

Operational Limit

During this event, the dispatcher determined that it would take more than 24 hours for the local resources to restore power. Consequently, the line crews, tree crews and trouble men were augmented substantially by available resources, including staff from other operating areas, contractor employees and technical staff. According to PacifiCorp, within the operating areas identified, approximately 30 full-time equivalents (FTEs) would be required for normal operational limits. However, the company required 82

FTEs. This requirement is more than two fold the regular operations. Therefore, we conclude that the Event exceeded the operational limit.

Design Limit

According to PacifiCorp, this event was initiated by a thunderstorm with lightening, rain and winds with maximum sustained speed of over 35 mph and a peak gusts of over 43 mph moving into the area. The combined weather phenomena resulted in 1 broken distribution pole, 3 broken crossarms, 1 broken transformer and 65 blown fuses (largely caused by broken trees and branches). PacifiCorp indicated that the crews tasked with restoring reported that there were some localized areas where the microburst winds were high as evidenced by the damage to utility structures as well as broken trees and branches. However, there is no official record of these microbursts. Therefore, the Division concludes that the company has not provided enough evidence to support that the design limit has been exceeded.

EVENT EIGHT

Event Description

On August 21, 2003 through August 23, 2003 (Event 8), A severe thunderstorm with severe winds with maximum sustained speed of over 35 mph and peak gusts of over 100 mph brought lightning, marble-sized hail, and torrential rains to many areas in Utah (American Fork, Layton, Ogden, Salt Lake City Metro, Smithfield, and Tremonton). This caused widespread damage on the power system and resulted in a sustained outage for more than 10% of the customers in those operational areas with 15,960,533 customer minutes lost, 469 sustained incidents, and 104,708 sustained customers off. The total cost of the damage was $329,229 of which $259,120 was expense and $70,109 was capital cost.

Ten Percent Criterion

Event 8 affected customers in American Fork, Layton, Ogden, Salt Lake City Metro, Smithfield, and Tremonton. The percentage sustained customers off during the August 21 through 23, 2003 by operating area is as follows:

Table 1. Percentage Sustained Customers Off During Event Eight

Operating Area	Sustained Customers Off	Average Customer Count	Percentage Sustained Customers Off
American Fork	6,412	64,756	10
Layton	25,951	56,996	46
Ogden	13,599	92,133	15
Salt Lake City Metro	33,102	203,243	16
Smithfield	14,036	19,945	70
Tremonton	11,608	7,905	147*

* The percentage of customers experiencing sustained outage exceeded 100% because some customers experienced multiple sustained outages.

Table 1 shows that at least 10% of the customers in all of the six affected operating areas experienced a sustained outage.

Operational Limit

After determining that local resources were not sufficient to restore power within 24 hours, the company increased the resources available to restore the power by calling in staff from other operating areas, contractor employees and technical staff. According to PacifiCorp, under normal operational limits, these operating areas would require 60 full-time equivalents (FTEs). However, the company required 217 FTEs. This requirement is more than three fold the regular operations. Therefore, we conclude that the Event exceeded the operational limit.

Design Limits

In their filling and in subsequent discussions with the Division, PacifiCorp indicated that the root cause for the power outage of August 21 through 23, 2003 was a severe thunderstorm that brought lightning, marble-sized hail and torrential rains with winds with maximum sustained speed exceeding 35 mph and peak gusts of over 100 mph. This resulted in 1 broken transmission pole, 18 broken distribution poles, 8 broken service transformers, 26 broken crossarms, and 137 blown fuses (a result of broken trees, branches and lightning strikes).

The recorded wind gusts of 100 mph exceeded the basic transmission design for resistance. Because the distribution lines are designed to withstand lower wind speeds than the transmission lines and because of their higher point loads, the wind withstanding standard for the distribution system was also exceeded. Because the system is designed with proper weak links, the wind tolerance levels of the transformers, crossarms were also exceeded. Therefore, this event exceeded the design limits for which the system was built and maintained.

Restoration Problems

The efforts to restore power were hampered by closed roads[1] and severe winds. This prolonged the transit time for the restoration personnel contributing to the duration of outage in this event. Besides, the widespread impact of the storm across multiple operating areas limited the Company's ability to pull in additional resources from surrounding areas to provide restoration assistance.

---

[1] During this time I-80 was shut down due to tractor-trailer turning over on the freeway. Roads in some other areas were under water.

EVENT NINE

Event Description

On October 30, 2003 through November 4, 2003, a snowstorm of 4.8 inches with 0.87 equivalent inches of precipitation and wind speed gusts recorded at 53 mph passed through several operating areas. Greater than normal foliage on trees accumulated more snow than bare branches would, weighing them down resulting in many significant tree issues, including limb breakage and limbs dipping further toward power lines. Additionally, wind gusts blew through and further stressed the heavily weighed branches. This event caused a widespread damage to the power system and caused more than 10% of the customers in several operating areas (American Fork, Cedar City, Jordan Valley, Layton, Ogden, Park City, Salt Lake Metro, Smithfield, and Tremonton) to experience a sustained outage with 24,785,657 customer minutes lost, 1,119 sustained incidents, and 124,640 sustained customers off. The total cost of the damage was $525,000 of which $500,000 was expense and $25,000 was capital cost.

Ten Percent Criterion

The event of October 30 through November 4, 2003 caused a sustained outage to customers in several operating areas, American Fork, Cedar City, Jordan Valley, Layton, Ogden, Park City, Salt Lake City Metro, Smithfield, and Tremonton. The percentage sustained customers off during this event by operating area is shown in Table 2. Table 2 shows that at least 10% of the customers in all of the six affected operating areas experienced a sustained outage except Layton operating area in which only 8% of the customer in the area experienced a sustained outage.

Table 2. Percentage Sustained Customers Off During Event Nine

Operating Area	Sustained Customers Off	Average Customer Count	Percentage Sustained Customers Off
American Fork	19,999	64,756	31
Cedar City	6,117	25,184	24
Jordan Valley	27,420	185,813	15
Layton	4,375	56,996	8
Ogden	10,147	92,133	11
Park City	2,625	24,292	11
Salt Lake City Metro	46,814	203,243	23
Smithfield	4,404	19,945	22
Tremonton	2,739	7,905	35

Operational Limit

During event nine, the crew/tree crew and trouble men were augmented substantially by available resources, including staff from other operating areas, contractor employees and technical staff. Within the operating areas identified, approximately 60 full-time equivalents (FTEs) would be required for normal operational limits (this is 3-4 line crews for three shifts and 5 trouble men for 3 shifts). The company required 35 line crews, 26 tree crews, 43 trouble men and 29 assessors, or approximately 265 FTEs. This requirement is more than four fold the regular operations. Therefore, this event exceeded the operational limits.

Design limit

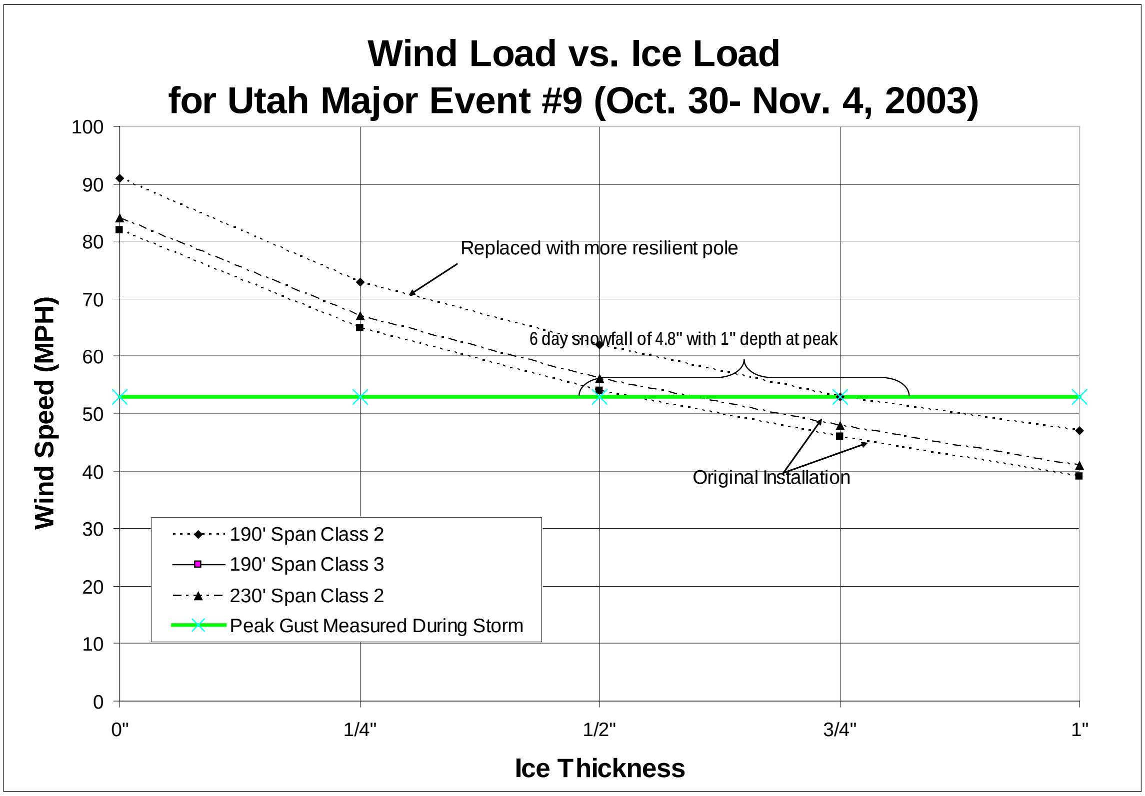
In this event there was a fall snowstorm with heavy wet snow of 4.8 inches with 0.87 equivalent inches of precipitation and subsequent wind gusts recorded at 53 mph. This event was more substantial than otherwise may have been experienced due to mild fall weather which resulted in greater foliage on trees which accumulated more snow weighing them down. The snow loading and wind gusts exceeded the design limits of the facilities.

According to PacifiCorp, the poles that broke were class 2 poles with 190’ span, and were originally installed before 1968. Because of their age, PacifiCorp considers them as having 2/3 of their original strength. These poles were loaded with double-circuit power lines. To determine whether the snow storm and the subsequent winds of October 30 through November 4, 2003 has exceeded the design limit of these poles, one has to determine the maximum combination of wind and ice loads the poles were designed to withstand. Based upon calculations performed by PacifiCorp staff, during this event, in which no allowances were considered for telecommunications or other conductors, the graph shown below was developed. The graph illustrates the combination of ice thickness and wind speed that the poles were constructed and maintained to withstand.

The horizontal axis of the graph is the ice thickness (inches) and the vertical axis of the graph is the wind speed (mph). The horizontal curve represents the peak wind gust at the time of the storm. The three curves labeled as 190ft span class 2, 190ft span class 3, and 230ft span class 2 are the allowable pole strengths for the respective designs to withstand certain combinations of wind speed and ice thickness. For instance, if the installed pole were 190 inches span class 2 and the ice thickness were ¾ of an inch, then the maximum wind speed that the pole can withstand is 53 mph. Any wind speed over 53 mph would break the pole.

The snowstorm of October 30 through November 4, 2003 and the subsequent wind resulted in a combination of 1 inch thick ice around the conductors and a wind gust of 53 mph. For a 190ft span class 2 pole with conductors covered by a 1 inch thick ice, the maximum tolerable wind speed is less than 50 mph. This indicates that the 53 mph wind speed exceeded the design limit of the poles. This resulted in a breakage of 5 distribution poles, 25 crossarms, 3 braces, a transformer, and 12,083ft conductor and 159 blown fuses (as a result of broken trees and branches).

Figure 1. Calculated Pole Strengths during Event Nine



EVENT TEN

Event Description

Late in the evening of December 25, 2003, a massive snowstorm clobbered parts of Utah. The hardest hit area was from Ogden to American Fork and the Park City and Tooele service territories. The amounts of snowfall accumulation during the first two days of the snowstorm were approximately 12 inches in Salt Lake City, 17-19 inches in Layton and Ogden, and 3-4 inches in Draper and American Fork. Records from the National Climatological Data Center show that the snowstorm in Salt Lake City on December 26, 2003 (10.6 inches) surpassed the record daily snowfall for the 26th of December. The old record was 4.3 inches in 1936. The snowfall continued, but at a lower intensity, through January 3. The total snow accumulation was 23.5 inches in Salt Lake City, 35 inches in Ogden-Layton, and 16.5 inches in Draper-American Fork. The moisture content of the snowstorm was on the average 0.103 precipitation/inch of snow. The moisture content level for this storm was the third highest in 75 years for Salt Lake City.

The Utah Center for Climate and Weather classified this snowstorm event as a "mega snowstorm," defined as more than 10 inches of snow accumulation in a 24-hour period. Besides the heavy wet snowstorm, windstorms hit these same areas as evidenced by weather data collected from the Salt Lake Airport by the National Climatologic Data.

Table 3. Weather Data From Salt Lake City Airport, National Climatologic Data Center

Date	Peak Gust* (mph)
12/25/2003	29.94
12/26/2003	
12/27/2003	
12/28/2003	
12/29/2003	40.3
12/30/2003	38.3
12/31/2003	24.18
1/1/2004	41.34
1/2/2004	47.21
1/3/2004	24.18

* Missing values are due to the fact that there was no reasonable reading for those dates.

The storm caused widespread damage on the power system and resulted in a sustained outage for more than 10% of the customers in the Jordan Valley, Layton, Ogden, Park City, Salt Lake City Metro, and Tooele operational areas. In its filing, the Company included American Fork as one of the operating districts affected by a Major Event. The Division believes that American Fork should be excluded from the filing for only 2% of its customers experienced a sustained outage. There were 159,038,976 customer minutes lost and 318,379 sustained customers off from the aforementioned six operating areas. The total cost of the damage was estimated to be $12,000,000.

Ten Percent Criterion

The Holiday power outage affected customers in seven operating areas, American Fork, Jordan Valley, Layton, Ogden, Park City, Salt Lake City Metro, and Tooele. The percentage of customers who were interrupted for a sustainable period during this event by operating area is shown in Table 3.

Table 3 shows that at least ten percent of the customers in six of the seven affected operating areas experienced a sustained outage. In American Fork only 2% of the customers in the area experienced a sustained outage. The Company included these customer outage events in its earlier filing. The Division believes this operating area

Table 4. Percentage Sustained Customers Off During Event Ten

Operating Area	Sustained Customers Off	Average Customer Count	Percentage Sustained Customers Off
American Fork	1,458	64,756	2
Jordan Valley	83,701	185,813	45
Layton	12,301	56,996	22
Ogden	38,401	92,133	42
Park City	5,678	24,292	23
Salt Lake City Metro	173,225	203,243	85
Tooele	5,073	12,815	40

should not be considered as a part of this Major Event, despite the resources within the operating area being applied to the restoration effort.

The numbers in Table 4 are based on the attached Major Event Report which should replace the Major Event report that was attached to the Company's original filling. In order to estimate outage incidents and outage duration, the Company simulated trouble calls within CADOPS environment. From this simulation, the Company identified the number of sustained customers off, the number of customer minutes lost and the number of sustained outage incidents. The sum totals of these were entered into the reporting system in one entry in Salt Lake City Metro. This distorted the number of sustained customers off, the number of customer minutes lost and the number of sustained outage incidents for all operating areas, assigning too much to Salt Lake City Metro and too few to the other operating areas. These numbers are what the Company used in its filling. In response to the Division's request that the Company properly assign these numbers to their respective operating districts, the Company provided the attached Major Event Report which should replace the one attached to the original Company filing.

Operational Limits

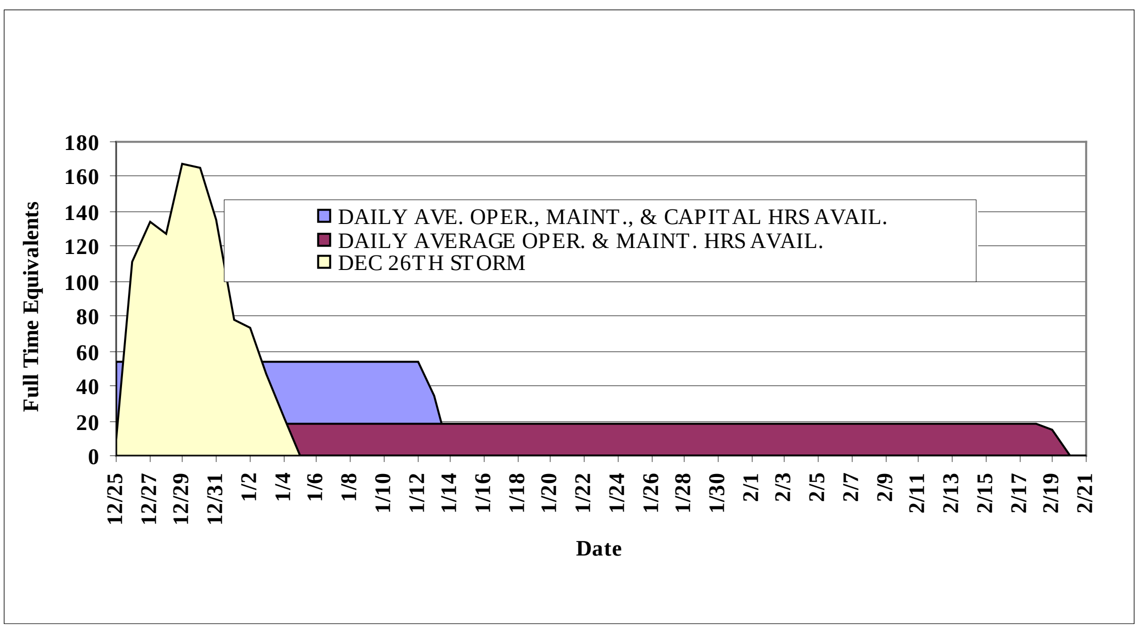
The December power outage affected customers in six operating areas, Jordan Valley, Layton, Ogden, Park City, Salt Lake City Metro, and Tooele (As stated above American Fork customer outages and staffing are being excluded from the event). The average daily available wrench turners[2] (in terms of FTE) in these operating areas were about 55. This consisted of about 18 and 25 FTE of Company employees doing normal operations and maintenance (normal maintenance includes, among other things, outage restoration, overhead and underground line maintenance, inspections, customer field orders, and miscellaneous operations) and capital work, respectively, and about 1 and 11 FTE of contract employees doing normal operations and maintenance work and capital work, respectively. However, the Company used 1,069 FTE to restore power. This allowed the

[2] Wrench turners are employees/contractors able to perform restoration work. Wrench turners do not include support personnel such as damage assessors, estimators, operations clerks, and managers.

company to fully restore power by January 4, 2004. The resources used consisted of Company employees from in and outside the affected areas, contractors and other utilities in the surrounding areas[3].

Figure 2 shows that if the Company had to use only its local Company and Contract employees doing the normal operations and maintenance work to restore the power, it would restore power fully by February 19, 2004. If the Company had to use, in addition to the aforementioned employees, local Company and contract employees doing capital work, it would restore power by January 13, 04. Hence, because both of these cases would keep many customers out of power for unnecessarily long time, the Company was forced to call in outside resources. Therefore, since the Company had to use more resources, about 1,069 FTE, than was available, about 55 FTE, the operational limit has been exceeded.

Figure 2. Length of Restoration Time: Actual Versus Two-Year Average Daily Full Time Equivalents of Internal staff and Contractors.



[3] The details of how the restoration effort progressed can be found in the PacifiCorp's Utah Holiday 2003 Storm Inquiry Report to the Commission.

Design Limit

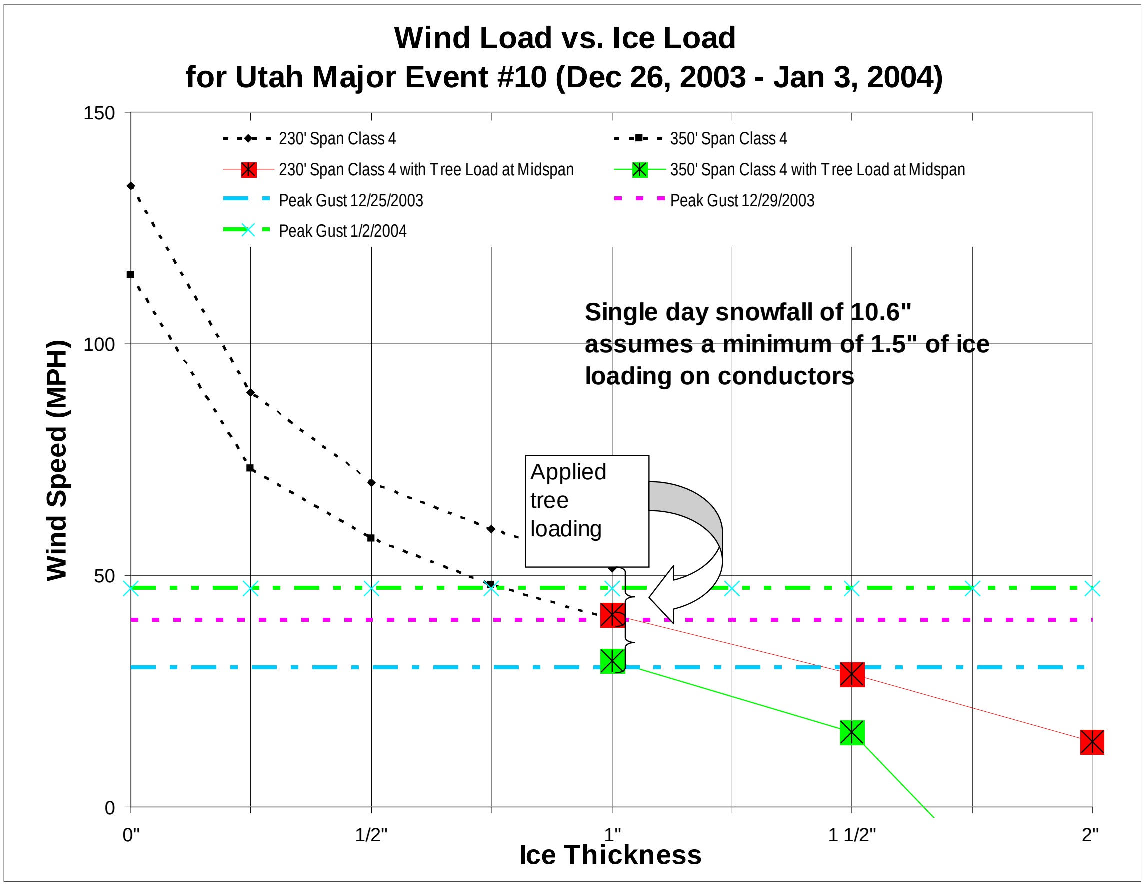
In this event there was a snowstorm with heavy wet snow with 1.09 inches of precipitation. There also were wind gusts recorded at per Table 3 above. The heavy wet snow caused trees falling on the power system. The combined effects of the snow loading, wind loading, and trees exceeded the design limits the power system was designed to tolerate causing extensive damage to the system.

According to PacifiCorp, the poles that failed were class 4 with 230ft and 350ft span. These poles were originally installed before 1986, hence are considered as having 2/3 of their original strength. Based upon calculations performed by PacifiCorp staff, during the wind and snow event of December 25, 2003 through January 3, 2004, in which no allowance was taken for telecommunications or other attached conductors (even though these would have reduced the pole's tolerance to ice, wind and tree impacts), the graph shown below was developed (Figure 3). Figure 3 illustrates the combination of ice thickness, wind speed and tree impact that the poles were constructed and maintained to withstand.

The horizontal axis of the graph is the ice thickness (inches) and the vertical axis is the wind speed (mph). The three horizontal curves represent the peak gust wind gust at three different days. The top one is for January 2, 2004, the middle one is for December 29, 2003, and the bottom one is for December 25, 2003. The two downward slopping curves are the allowable pole strengths for the respective designs to withstand certain combinations of wind speed, ice thickness and tree impact. The top one is for class 4 pole with a span of 230ft. The bottom one is for class 4 pole with a span of 350ft. The portion of these graphs to the left of 1 inch ice thickness shows the combination of wind speed and ice thickness that the poles are designed to tolerate. After the 1 inch ice thickness level, the tree impact is imposed resulting in a downward shift of the curves.

Figure 3 shows that the 230ft span, class 4 ad the 350ft span, class 4 poles that failed would have been able to withstand wind speeds of about 16 and 28 mph, respectively, when stressed with 1.5 inches of ice load and the load of the fallen trees. Therefore, the conditions that occurred during the December 25, 2003 through January 3, 2004 event exceeded the design limits of the facilities.

Figure 3: Calculated Pole Strengths during Event Ten



Restoration Problems

The duration of the outage was prolonged by road closures, poor visibility, downed trees across roads, and CADOPS failure. Besides, some of the crews and equipments were to be transported from other states[4].

---

[4] A more detailed description of the restoration problems the Company encountered can be found in the Company's Utah Holiday 2003 Storm Inquiry Report to the Commission.