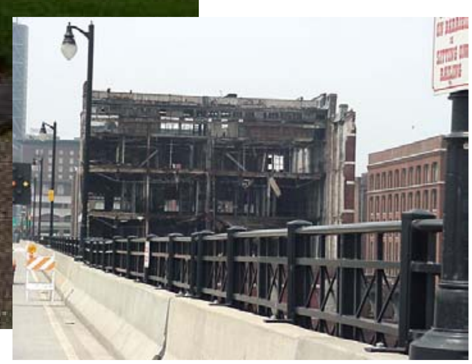
Report on

AmerenUE's Storm Outage Planning and Restoration Effort Following the Storms on July 19 and 21, 2006



Photos Courtesy of: KMOV-4, Post Dispatch, and National Weather Service

Case No. EO-2007-0037
Missouri Public Service Commission Staff
November 17, 2006

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Executive Summary

Our economy and quality of life are more closely tied to reliable electric service than ever before. Consumers and businesses are ever more dependent on the electric devices in their homes and businesses for every day life and comfort. We are in an era where even momentary outages create major inconveniences and economic losses, and multi-day outages are viewed by many as intolerable.

According to the Electric Reliability Organization (ERO), which was recently created from the North American Electric Reliability Council (NERC), demand for electricity is expected to increase over the next ten years by nineteen percent in the U.S. This increase in demand for electricity will require construction of additional power plants and transmission and distribution infrastructure. This increase in demand will also require that the electric utility industry carefully maintain and upgrade its existing transmission and distribution infrastructure if service reliability is to be kept at an acceptable level.

St. Louis is often referred to, by those who deal with storm restoration efforts, as an "urban forest." While this greatly enhances the city's beauty and helps people keep their utility bills lower than they would be otherwise during normal summer and winter weather, this density of large old-growth trees represents a risk to utility service following storms with high winds or heavy ice accumulations.

This report examines AmerenUE's storm outage planning and restoration effort following the severe storms on July 19th and 21st of this year. As discussed in the Storm Arrival Times & Intensities section of this report, these storms were extraordinary in terms of their wind speeds and direction and the fact that they occurred only two days apart. These storms plunged hundreds of thousands of customers into darkness on July 19th. Many of these customers then had to endure no air conditioning on July 20th, one of the hottest days on record this year. This was a life threatening situation to many, and all available city, county, and state resources were activated to respond. Staff is sincerely grateful for the many utility personnel and contractors that came to Missouri to help and worked long hours under dangerous conditions in sweltering weather.

This is the third consecutive year that AmerenUE has experienced significant major storm outages. Staff conducted informal investigations following the storms in 2004 and 2005. Both of these Staff reports can be accessed at the following links:

2004 Report: http://psc.mo.gov/publications/UE_Storm_Rest_Report.pdf

2005 Report: http://psc.mo.gov/publications/UE_Storm_Rest_Report_2005.pdf

The number of customers without service following the major storms in 2004 and 2005 is shown in the following table:

Restoration Time
(Percent Restored)

	2005 Storm	2004 Storms
Less than 24 Hours	51%	78%
Less than 48 Hours	74%	95%
Less than 72 Hours	94%	99%
Less than 96 Hours	99%	100%
Customers Restored	216,548	224,672

The following table shows the rate of outage restoration in Missouri following the storms on July 19, 2006 (provided by AmerenUE, from Outage Analysis System (OAS) data):

Date/Time	**Days**	**Customers Restored per Day**	**Total Customers Restored**	**% Restored per Day**	**Cumulative % Restored**
07/20/06 18h	1	109,173	109,173	17%	17%
07/21/06 18h	2	93,942	203,115	15%	31%
07/22/06 18h	3	96,745	299,860	15%	46%
07/23/06 18h	4	85,486	385,346	13%	60%
07/24/06 18h	5	67,380	452,726	10%	70%
07/25/06 18h	6	52,599	505,325	8%	78%
07/26/06 18h	7	47,257	552,582	7%	86%
07/27/06 18h	8	49,837	602,419	8%	93%
07/28/06 23h	9	43,692	646,111	7%	100%

Staff and AmerenUE were in contact daily during this restoration effort. AmerenUE provided Staff, by email, the information that it provided to local St. Louis media every morning and afternoon. The media information included the number of customers without electrical service and the progress of the restoration of service. The www.ameren.com Outage Map was accessed by Staff frequently to review restoration status by zip code during this restoration effort. Staff also participated in the SEMA/EOC meetings to gather information on utility related emergencies and provide assistance wherever possible.

In addition to teleconferences during the outage restoration effort, the Staff met with the personnel responsible for implementing AmerenUE's restoration plan at AmerenUE's Emergency Operations Center (EOC) in St. Louis several times. At the first meeting, AmerenUE provided the Staff with information responsive to a list of areas Staff had expressed an interest in discussing. The Staff followed up this meeting with additional questions and meetings to discuss AmerenUE's responses.

AmerenUE activated its EOC promptly as the storms on July 19th were impacting the St. Louis area. Shortly after activating its EOC, AmerenUE started seeking assistance through its Mutual Assistance Agreements. Initially some utilities were hesitant to release crews due to extremely hot weather causing peak demand conditions on their systems and the forecast for more severe weather. On July 21st the ability to receive additional assistance improved significantly as the probability of additional severe weather diminished.

AmerenUE is currently addressing its backlog of tree trimming along urban and rural circuits within its Missouri service territory. AmerenUE is in compliance with its agreement to address this backlog on or before December 31, 2008. Associated with this investigation, Staff carefully reviewed a number of outage metrics and has concluded that more aggressive programs for clearing vegetation from feeders and sub-transmission lines should be implemented by AmerenUE if damage from future storms is to be reduced.

It must, however, be emphasized that even if all of the trees in AmerenUE's service territory were trimmed per current procedures immediately before these storms hit the St. Louis area, much of the damage observed would have still occurred. Significant damage to AmerenUE's system was caused by trees and tree limbs that would not be removed by AmerenUE's current trimming programs or are not on AmerenUE's right-of-way.

Staff carefully reviewed AmerenUE's call center operations in light of a number of telecommunications and website problems early on in this major outage restoration. The number of customers without power in this outage was unprecedented. It overloaded AmerenUE's website and contributed to the telecommunications problems experienced. The website problem has been addressed by AmerenUE and they plan to make further enhancements in the future in this area. Problems experienced by those trying to call AmerenUE to report their outage early on were caused by a network protective measure implemented by AT&T referred to as "call gapping." Staff has included a recommendation in this report relative to this issue.

Staff received numerous consumer complaints during and following this major outage restoration effort. Additional public comments and complaints were received during the public hearings held in this case. As discussed in the Call Center Operations section of this report, problems with telecommunications early on in the restoration effort contributed to the number of complaints. Many customers also expressed concerns with the status of tree trimming along power lines and the length of time they were without service. Frequency of outages not related to storms was also something noted in the public hearings. Associated with this investigation, Staff looked at a number of general reliability related items, and this report includes several recommendations in this area based on Staff's observations.

AmerenUE's compliance with recommendations in the 2005 Storm Report was also assessed. Staff believes that AmerenUE has adequately addressed, or is adequately working to address, Staff's recommendations in the 2005 Storm Report.

Staff reviewed AmerenUE's restoration planning process, and based on comparisons with restoration practices literature from several sources, concluded that AmerenUE's planning process was well developed. Staff also concluded, based on comparisons with other storm restoration efforts around the country, that AmerenUE's restoration effort was well executed. This does not mean that Staff did not find areas where it has recommendations for improvement.

As noted in the Commission Order creating this case, utility services other than electric were impacted. In the SEMA/EOC meetings and the public hearings in this case, problems with telecommunications and water utility service were noted. Staff has assessed the impacts of extended power outages on these utilities, and the Other Utility Impacts section of this report provides observations and recommendations in these areas.

As used in this report, AmerenUE refers to Union Electric Company d/b/a AmerenUE, an electric utility the Commission regulates, and Ameren refers to the parent of AmerenUE – Ameren Corporation. The Commission does not regulate Ameren Corporation. Where Company is used in this report regarding an electric utility, this is generally referring to Ameren Corporation.

Staff's recommendations are inserted in the sections of this report where their basis is established. The first group of recommendations below is specific to Staff's observations related to storm outage planning and restoration efforts following the July 19th and 21st storms. The second group of recommendations below is specific to Staff's observations regarding general reliability and infrastructure maintenance.

Recommendations Specific to Outage Planning & Restoration:

1) Staff should conduct a roundtable with all the electric utilities in Missouri to discuss best practices in restoration planning and execution.

2) AmerenUE should continue to enhance its safety programs to identify and make downed lines safe after a major outage event.

3) AmerenUE should continue to maintain its mutual assistance agreements, and in each major restoration effort evaluate the necessity of utilizing these agreements so that it will have access to such resources when needed.

4) AmerenUE should explore the structure of a mutual assistance agreement with the Association of Missouri Electric Cooperatives (AMEC) for future emergencies where either AmerenUE or one or more of the electric cooperatives needs assistance following major storms like those experienced on July 19th and 21st.

5) AmerenUE should either maintain or have the ability to produce up-to-date maps of its infrastructure and roads to supply to crews during major outage events.

6) AmerenUE should continue to work toward elimination of its trimming backlog per its prior agreement with the Staff in Case No. EW-2004-0583.

7) Adopt and implement a Commission rule to require each electric utility to annually submit a report on its vegetation management program's structure, objectives, status, and funding.

8) AmerenUE should implement vegetation management programs that:

a) Target more substantial removal of vegetation along power lines throughout its system, including side clearances and overhangs, along feeders and sub-transmission systems.
b) Target removal of problem trees within the utility's easement and possible replacement with ornamental trees or other low-growing vegetation.
c) Target communications with landowners, who have trees off the right-of-way that represent a significant risk to sub-transmission and feeder lines, to find reasonable means to reduce the outage risk from these trees.
d) Trim trees in areas with particularly high densities of vegetation on a more frequent basis. Currently urban areas are targeted for a four-year cycle; it may be appropriate to go to a three-year cycle in some areas.

9) AmerenUE should include a clear message within the Voice Response Unit (VRU) script to address non-pay disconnections during the course of major storm outage restorations.

10) AmerenUE should continue discussions with AT&T regarding notification whenever call gapping is to be implemented on switches that affect the provision of critical AmerenUE services.

11) AmerenUE should promote customer registration on its website to ensure that customers can access customer-specific information on service restoration in the event of a storm related outage.

12) City and county agencies, in conjunction with AmerenUE, should facilitate the development of neighborhood watch groups, or assess the ability of the current Operation Weather Survival (OWS) network system, to check on special needs customers during an extended outage.

13) AmerenUE should continue to make efforts to improve participation in the Storm Schools it offers for the media, fire, police, city and county officials.

14) AmerenUE should further enhance its communications with field crews performing restoration work regarding AmerenUE's authority to cut trees outside of its right-of-way for the purpose of accessing its right-of-way for storm restoration work.

15) While centralization of AmerenUE's storm restoration process has brought about a number of coordination efficiencies, Staff believes that district managers should be available to local officials to deal with emergency situations and be provided with authority to request priority treatment of projects in their areas that require special attention.

16) AmerenUE's participation in the SEMA/EOC coordination phone calls during this restoration effort was extremely helpful to all the agencies involved. Staff recommends that SEMA request that each electric utility with damaged infrastructure attend and actively participate in all future storm restoration efforts where the level of damage prompts SEMA/EOC activation.

17) AmerenUE provided its storm center direct number to several city, county and state officials. Several officials reported that having this number available was extremely helpful to them. AmerenUE also reported that the calls received on this number did help it prioritize work on several critical projects. Unfortunately, AmerenUE also reported that too many individuals distributed this number to a broader group than it was intended to be provided to and at times issues that were not of a critical nature were being called in on this number, reducing the efficiency of personnel tracking outage repairs and dispatching crews. Staff recommends that AmerenUE continue to provide this number to key officials but caution these officials to be very careful in their distribution of this number, and that it be used only for emergency purposes.

18) (Telecommunications) The Commission may want to give consideration to expanding its current back-up power requirement to include battery reserves and/or generators for Digital Line Carrier and node locations as well as the customer's location.

19) (Water) Missouri American Water Company (MAWC) should assess additional methods to get information to customers regarding boil orders, if any, during major outage events when customers do not have access to the normal media they use to receive information. These additional means may include the OWS network system, the Post Office, flyers posted at shopping centers, super markets, gas stations, and other locations where people are likely to read a notice.

20) (Water) MAWC should assess whether it needs to have on-site back-up generators installed, or have access to portable generators, at its major production facilities in order to provide reliable water service in the future given the outage history they have experienced at these facilities.

Recommendations Specific to Reliability & Infrastructure Maintenance:

1) Adopt and implement a Commission rule that requires electric utilities to annually report certain standard reliability metrics, their programs for attaining or improving these metrics, the status of these programs, and program funding levels.

2) Adopt and implement a Commission rule that requires electric utilities to annually submit a report on the structure, objectives, status, and funding of their transmission and distribution infrastructure inspection and maintenance programs.

3) AmerenUE should assess its current non-feeder distribution pole inspection programs and report to Staff within 180 days on which of the following approaches it believes is appropriate regarding maintenance and inspection of these distribution poles:

a) Enhance its existing distribution pole audit programs (overhead circuit inspection program and pole attachment audits) to increase the likelihood that these audits will identify distribution poles that should be rejected or receive additional treatment to extend their useful life;
b) Implement a new program specifically for inspection of distribution poles that is structured to have a high likelihood of identifying poles that should be rejected or receive additional treatment to extend their useful life;
c) Demonstrate that the current rate of replacement of distribution poles is consistent with the anticipated average age of currently installed distribution poles and their expected useful life, and therefore, no distribution pole audit program changes are appropriate at this time; or
d) Propose an alternate approach to those programs noted above.

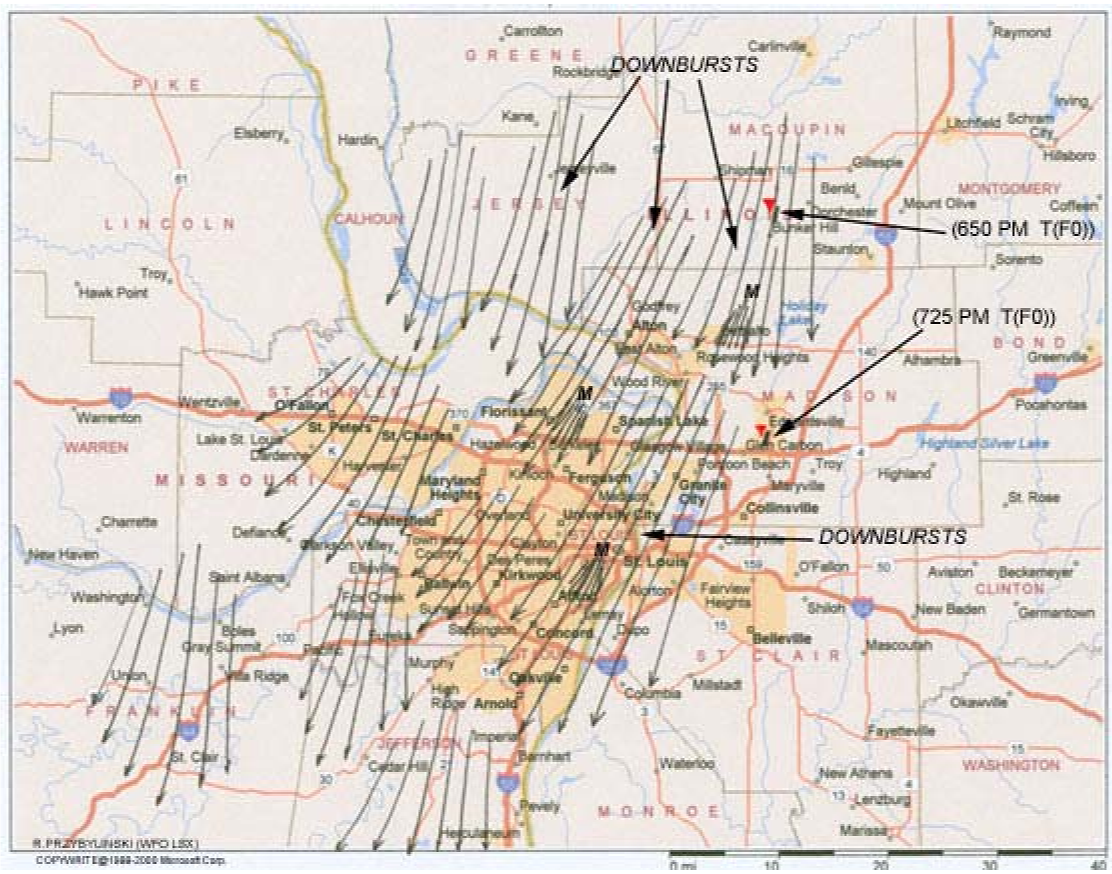
Storm Arrival Times & Intensities

In July of this year a deadly heat wave developed across much of the United States. Temperatures throughout much of the country topped out above the century mark with heat indices approaching 115^{o} F in St. Louis. According to the National Oceanic and Atmospheric Administration (NOAA), this July was the second warmest since 1895. The National Weather Service (NWS) reported that, in all, twenty-two deaths in ten states were blamed on the excessive heat during this heat wave. This heat wave was eventually broken by a series of frontal systems in late July.

The first of two series of severe thunderstorms hit the St. Louis metropolitan area on July 19th at approximately 6:20 PM. These thunderstorms were described as follows by the NWS (link: http://www.crh.noaa.gov/lsx/?n=july_2006):

> On July 19th, after reaching a high temperature of 100 degrees, a cluster of thunderstorms, also known as a mesoscale convective system, formed across Northern Illinois and propogated southwest across West Central Illinois and Eastern Missouri. The outflow boundary and the thunderstorm complex produced straight-line winds or downbursts that created widespread wind damage from Central Illinois across the St. Louis Metropolitan Area and into the Eastern Ozarks. The damage sustained in the St. Louis Metropolitan Area was consistent with wind speeds between 70 and 80 mph. Areas of damage across Illinois suggested that wind speeds could have approached 90 mph. Two tornado tracks were also uncovered across Southwest Illinois near the towns of Bunker Hill and Edwardsville. Over 500,000 customers were left without power, and thus no air conditioning.
>
> A State of Emergency was declared for the St. Louis Area, and Governor Matt Blunt called in the National Guard to help with heat evacuations and clean-up efforts from the severe thunderstorms. The temperature rose near 100 degrees once again on Thursday and heat index values were as high as 115 degrees in the affected region.

NWS Downburst & Microburst Map for July 19, 2006 Storms:



A trained spotter in Jefferson County, Missouri reported ninety-two mph wind gusts. NWS spotters reported extensive damage to trees in the St. Louis metropolitan area following these storms. Reports were also received of tractor-trailers being blown over and buildings being damaged. Unfortunately, the weather pattern that spawned these storms did little to lessen the extraordinarily high temperatures being experienced in St. Louis.

AmerenUE activated its EOC at approximately 6:40 PM on July 19th in response to the extensive damage that these storms were causing to its distribution system in the St. Louis area. This series of storms was declared a Level III (major) event. This level of storm is the most intense recognized in AmerenUE's Electric Emergency Restoration Plan (EERP). This guide has been developed by AmerenUE to communicate policy regarding EOC operations and to serve as a reference tool for managing restoration following major storms.

Storm levels defined in the EERP outline the response necessary to get customers back in service based upon the number of customers affected and the extent of damage. AmerenUE later determined, based on NWS information, that these thunderstorms had contained downbursts – straight-line winds of at least seventy-five mph that were sustained for as long as five minutes. A Category one hurricane has winds rated at seventy-four mph.

Governor Matt Blunt issued a series of Executive Orders immediately after these storms had impacted the St. Louis area activating emergency management organizations, including the State of Missouri Emergency Management Agency (SEMA).

In a St. Louis Post-Dispatch article on August 13, 2006, referencing damage to Tower Grove Park, sources reported that "114 trees overturned, and 100 more may need to be cut down" and "The storm was the second worst to hit the park since it was founded in 1868. The only event more destructive was the Great Cyclone of 1896…"
Link to website providing details on the Great Cyclone of 1896: (http://www.usgennet.org/usa/mo/county/stlouis/cyclone.htm).
Picture from this website link of damage in St. Louis:

Information on the Great Cyclone of 1896 describes wind speeds approaching eighty mph and a large tornado. In meetings with Staff, AmerenUE has stated that it believes the July 19th storm was a 1 in 100 year storm. Evidence of other damaging storms in 1924, 1927 and 1959 has been reviewed, but Staff has not yet found evidence of a more destructive thunderstorm in Missouri in the last 100 years.

A second series of severe thunderstorms hit the St. Louis metropolitan area on July 21st at approximately 10:50 AM. These thunderstorms were described as follows by the NWS:

> Another complex of severe thunderstorms formed across Central Missouri during the morning of July 21st on the trailing end of an outflow boundary from overnight convection across Southern Iowa and Northern Missouri. This cluster of thunderstorms formed into a bow echo as they pushed across the St. Louis Metropolitan Area producing another swath of wind damage from Central Missouri to Central Illinois. To the north of the apex of the bow a strong circulation produced several tornadoes. This led to many additional power outages and complicated clean up efforts from the July 19th storm damage. Some people who had just gotten their power back from the previous storm suddenly found themselves in the dark once again.

Trained spotters again reported high wind speeds and extensive damage to trees and structures. In this series of storms, one tree that was blown over killed a person. Fortunately, the frontal system that spawned these storms brought somewhat cooler temperatures, which was a welcomed change for the hundreds of thousands of people in the region still without power to operate air conditioning and the utility work crews working long hours outdoors.

Staff contacted Midwest ISO (MISO) regarding transmission damage from these storms, and MISO confirmed that several high voltage transmission lines, over 100 kV, were damaged by these storms. In total, one 345 kV transmission line was out of service for forty-five hours and seven 138 kV transmission lines were out of service for an average of twenty-seven hours. MISO noted that they operated the electrical transmission power system for this area within defined operating criteria while these transmission systems were repaired.

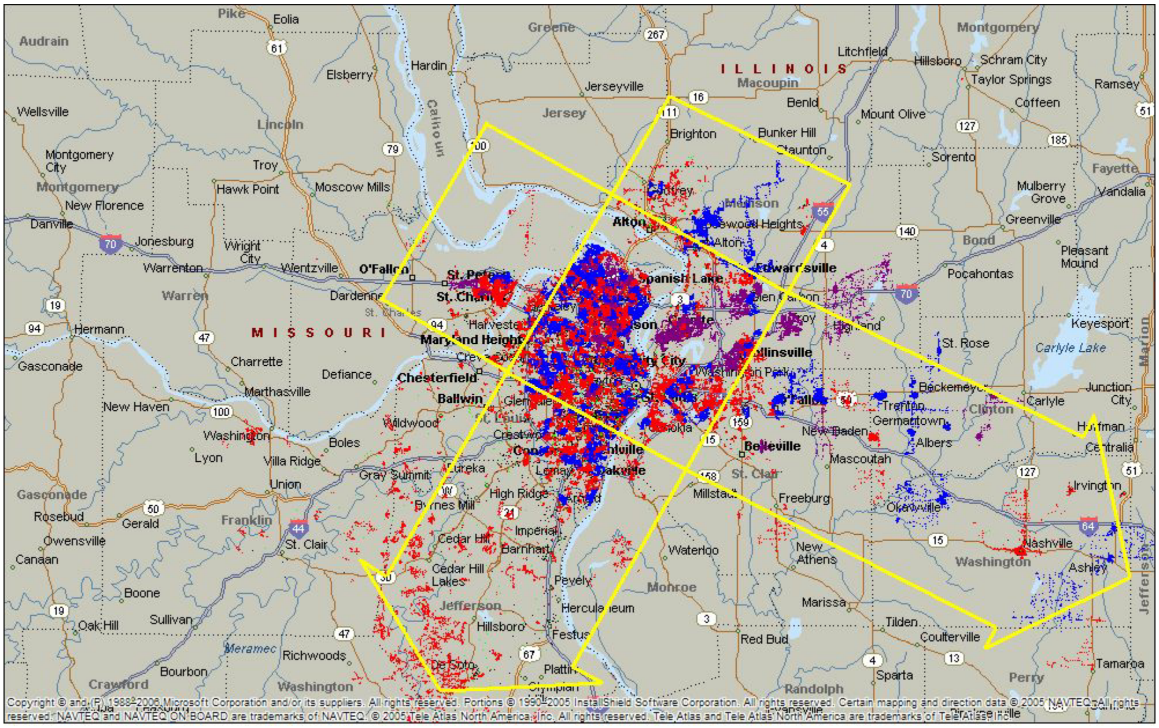
In the September 2006 edition of Forest Park Forever and Today an article titled *Summer Storms Sock It to Forest Park Trees,* Gary Bess, the Parks, Recreation and Forestry Director is attributed with estimating "that the July storm took out 15% of the trees in the City of St. Louis." Regarding damage in Forest Park, the article goes on to say that: "More than 125 trees were downed by the storms, with many more damaged to the extent that they must be removed due to safety concerns. Large limbs and debris littered the park as they did in neighborhoods all over the region."

Appendices G and H of this report include pictures and news articles from the St. Louis area after the storms on July 19^{th} and 21^{st}. These pictures and stories provide a graphic testimony of the severity of these storms and the extraordinary damage they inflicted in the St. Louis area. In an effort to compare the damage to infrastructure as a result of these storms versus past storms, St. Louis City Street Department data from this storm was compared to past storm observations.

According to AmerenUE, the City of St. Louis Street Department provided the following observations regarding damage from the July 19^{th} and 21^{st} storms:

Street Lights Blown Over = **90** (typically 10 to 12 in a major storm)
Broken Traffic Light Mast Arms = **45** (never more than 6 previously)
Damaged Traffic Signal Heads = **182** (typically 10 to 12 in a major storm)

When the paths of the storms on July 19th and 21st are overlaid on a map with electric outages plotted, the relationship between storm damage and outages is obvious (source: National Weather Service & Ameren Outage Analysis Maps):



As a result of these storms, on July 21, 2006, President Bush declared a Federal Emergency (Source: www.fema.gov, release number HQ-06-112):

> "…President Bush declared an emergency exists in the State of Missouri and ordered Federal aid to supplement State and local recovery efforts in the area struck by severe storms beginning on July 19, 2006, and continuing…"

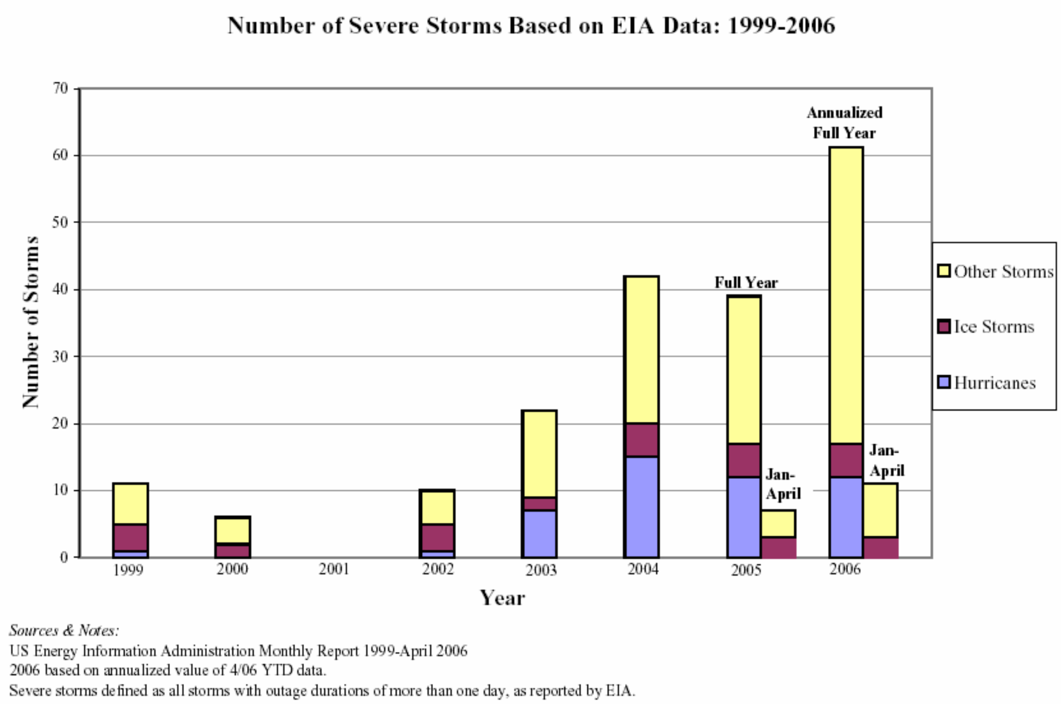
On August 21, 2006, Staff interviewed Ben Miller of the NWS associated with its analysis of the intensity of these weather events. When asked about the intensity of these storms, the paths they took, and the frequency of storms with this intensity, Mr. Miller shared a number of thoughts. Mr. Miller did believe that these storms were certainly stronger than normal thunderstorms, and he further noted that the St. Louis area had not experienced storms like these in quite a while.

Regarding the storms' paths, Mr. Miller thought that having the storms' "strongest cores" go right over the city was certainly unusual, and that coincidence more than anything else resulted in the storms observed over the city. Mr. Miller also stated that the path of the July 19th storm was particularly unusual. When asked about wind speeds, Mr. Miller thought that wind speeds of eighty to ninety mph were observed at several locations in these storms and that the state of Missouri may observe storms of this intensity perhaps once or twice every five years. Mr. Miller also stated that he believed that the direction of the wind in the July 19th storms likely contributed to the extent of damage to trees as different sets of trees were exposed to high wind velocities from new directions versus those experienced in past storms. Mr. Miller also noted that these storms had high microburst velocities that may have also contributed to the extent of damage.

Early in the 2006 thunderstorm season another major outage that was not as broadly covered by the media occurred on April 2, 2006. This series of thunderstorms was described by the NWS as follows:

> A line of severe thunderstorms developed during the afternoon across Central Missouri and quickly raced east across Eastern Missouri and into Central Illinois spawning tornadoes and bringing damaging winds in excess of 70 mph to a large portion of the St. Louis Metropolitan Area. Over 200,000 people lost power during the height of the storm. In addition, hail ranging from pea to baseball size was observed. Believe it or not, things could have been much worse across the area if this event would have taken place just a few weeks later. Thankfully, most of the trees had just began to bud, and there was little if any visible foliage. If this widespread severe wind event would have occurred when the trees had leaves on them, the number of people without power would have easily been doubled. During this event the National Weather Service in Saint Louis issued 65 warnings and received over a 160 severe weather reports. Two fatalities have been confirmed from this severe weather event in the St. Louis County Warning Area.

While the frequency and intensity of storms impacting St. Louis has certainly been extraordinary, and the associated damage to infrastructure particularly annoying to customers without power, it does not appear that an increasing frequency of severe storms is only being observed in St. Louis. AmerenUE has been researching the frequency of severe storms as captured by the Energy Information Administration (EIA) and provided Staff with the following graph based on its analysis:



In Staff's view, AmerenUE adequately tracked the risk potential of these storms before they hit the St. Louis area and had procedures in place that appropriately assessed the damage to its distribution infrastructure immediately after these storms. Staff has no recommendations in this area at this time.

The Storm Restoration Planning Process & AmerenUE's Response

This section of Staff's report examines AmerenUE's planning for major storm outages and their execution of that plan. Unfortunately, this is the third consecutive year AmerenUE has experienced major outages from severe thunderstorms. Each of these past restoration efforts has come with lessons for the future. In this investigation, Staff started its review by looking at other state commission storm examination reports as well as literature on storm restoration planning and execution.

One of the documents used by Staff in its analysis was Mercer Management Consulting's *Improving Storm Restoration Performance*, @ 2006. Link to this document: (http://www.mercermc.com/Perspectives/Perspectives_pdfs/StormReadiness.pdf)
Another document used by Staff in its analysis was Transmission and Distribution World magazine, August 2005 edition, article titled *Hurricane Restoration at Its Finest* by Ellen Parson.

A review of common best practices from these documents and others yields the following primary categories of major storm restoration planning and execution activities:

System Storm Center & Operations

- ✓ Having a Robust Crisis Management Plan & Sticking to It
- ✓ Employees Are Trained & Ready to Respond in Their Roles
- ✓ Storm Tracking & Notification System
- ✓ Damage Assessment & Repair Teams Trained & Ready to Respond
- ✓ Strong Mutual Assistance Agreements – Tree Trimming & Lineman
- ✓ Continuous Effective Communications (Hardened Facilities)
- ✓ Continuous Prioritization of Restoration Focus
- ✓ Repairing Health, Safety, Fire, Police, Water & Sewer Facilities Quickly
- ✓ Repairing Backbone Systems
- ✓ Identifying and "Making Safe" Downed Lines
- ✓ Scheduling of Necessary Personnel in Operations
- ✓ Maintenance & Replacement Programs for Critical Infrastructure
- ✓ Holding Regularly Scheduled, But Brief, Update Meetings to Discuss Status & Goals
- ✓ Maintain Flexibility for Changing Circumstances
- ✓ Presence at Emergency Operations Centers in Affected Areas

Staging & Logistics

- ✓ Equipment Inventory, Resupply Provisions & Distribution
- ✓ Advance Preparation of Equipment Supply Chain
- ✓ Identify Potential Pinch Points & Address Them
- ✓ Crew Safety & System Orientation Training
- ✓ System Mapping & Restoration Procedures
- ✓ Meal Planning & Distribution
- ✓ Truck Fueling & Security
- ✓ Soiled Clothing Pick-Up, Laundry & Return
- ✓ Staging Site Agreements with Shopping Centers, Hotels, Schools and Airports

Corporate Communications

- ✓ Pre-Storm Checklist for Customers
- ✓ Consistent Message with Best Available Information
- ✓ Regular Communications with All Media
- ✓ Arrange Press Tours of Damaged Areas
- ✓ Educate Consumers of Reasonable Expectations
- ✓ Specific Communications with Large Customers
- ✓ Website Information for Those with Access to Computers
- ✓ Call-Center People Having Access to Current Status Information
- ✓ Generator Use Safety Notifications

Community & Customer Relations

- ✓ Up-To-Date Contact Information & Keep State and Local Officials in Loop
- ✓ Listen to Local Government & County Agency Priority Needs
- ✓ Work Closely with Local Officials in Communicating Status
- ✓ Conduct Regional Community Disaster Response Workshops

Looking Back & Looking Forward

- ✓ Corporate Culture That Seeks Feedback on What Went Well & What Didn't
- ✓ Root Cause Analysis of Major Problems & Assessment of Ways to Improve in Future
- ✓ Look for Ways to Reduce Future Storm Impacts on System
- ✓ Workforce Recognition & Recovery

Staff notes that the list above does not include a number of elements specific to hurricanes, especially related to the ability to anticipate the approach of a severe storm and pre-deploy resources to areas expected to be impacted. Severe storms in Missouri do not generally come with nearly as much advance notice as a hurricane.

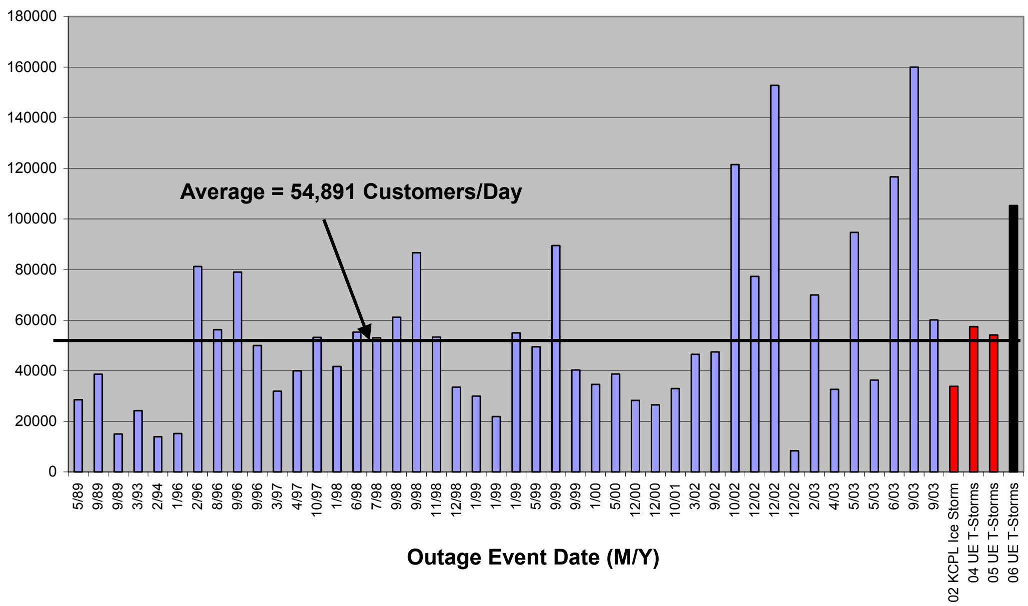
After reviewing the above list of primary elements of major outage restoration plans, Staff reviewed AmerenUE's restoration plan. Staff stepped through each of the items identified in the list above and found that AmerenUE's EERP, or other procedures, include all of the identified major elements. This observation does not mean that all elements were carried out flawlessly, only that AmerenUE's EERP does compare favorably with other best practices documents. In other sections of this report, Staff has identified a number of recommendations that if implemented may improve AmerenUE's ability to respond to major storm outages in the future.

Staff notes that even the best restoration plan does not assure a good restoration outcome following a major storm outage. To assess outcomes it is necessary to perform comparative studies of AmerenUE's restoration effort to other past restoration efforts. A document that was helpful in Staff's investigation in this area was Edison Electric Institute's (EEI) *Utility Storm Restoration Response* by Brad Johnson, an independent energy advisor, issued in January 2004. Link to this report:
(http://www.eei.org/industry_issues/reliability/power_outages/StormRestoreReport.pdf)

This report examines utility responses to forty-four major storms between 1989 and 2003. Staff took the data from this report and compared restoration statistics from this report to statistics from AmerenUE's restoration efforts in 2004, 2005 and this year. Staff provides its analyses in the following graphs with one caution: storms, their impacts on utility systems, and utility restoration performance may vary dramatically depending on a number of factors such as the percentage of the utility's total system damaged and the density of trees in the areas impacted.

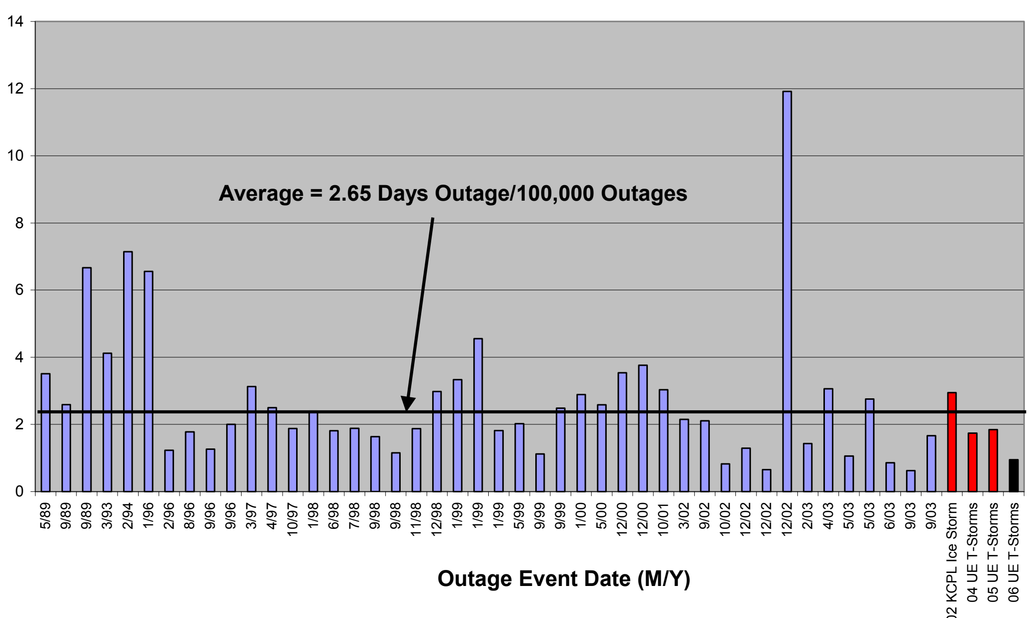
The first two comparisons Staff looked at were the number of customers restored per day and the average length of outage per 100,000 customers without service. As can be seen in the graph below, AmerenUE restored more than the average number of customers per day.

Average # of Customers Restored per Day



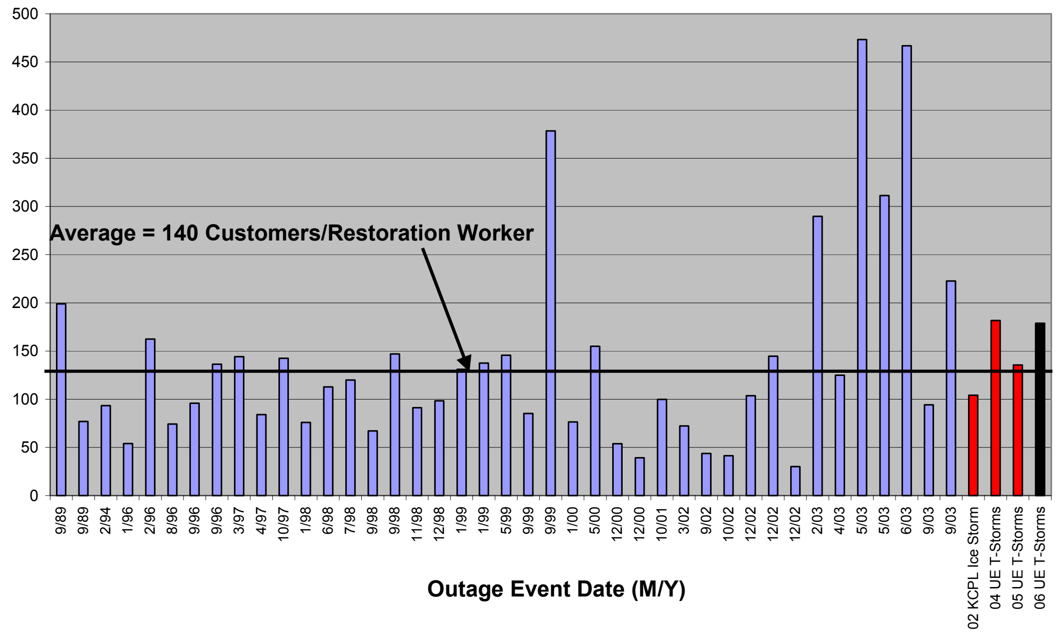
The graph below looks at this data in terms of average restoration timeframe per 100,000 customers experiencing an outage. As this graph shows, AmerenUE restored customers faster than the average outage length per 100,000 customers experiencing an outage.

Duration of Outage in Days per 100,000 Customers Out



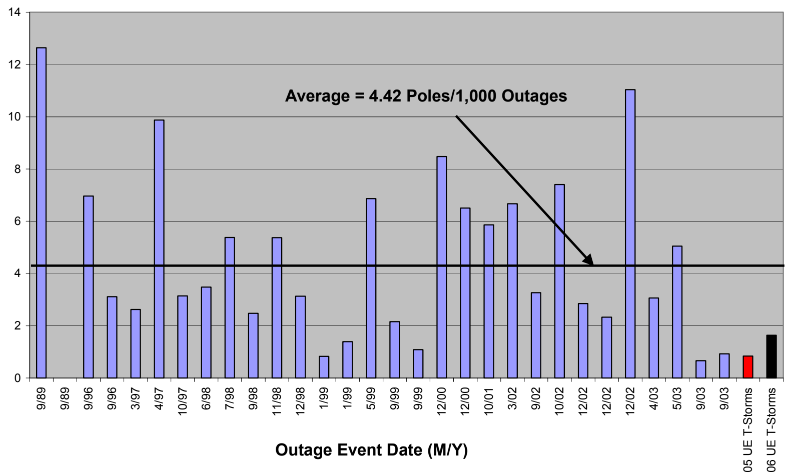
Staff then examined the productivity of restoration workers based on the number of customers restored per restoration worker. As this graph shows, AmerenUE's restoration crews restored more than the average number of customers per restoration worker.

Customers Restored per Restoration Worker for Major Storms

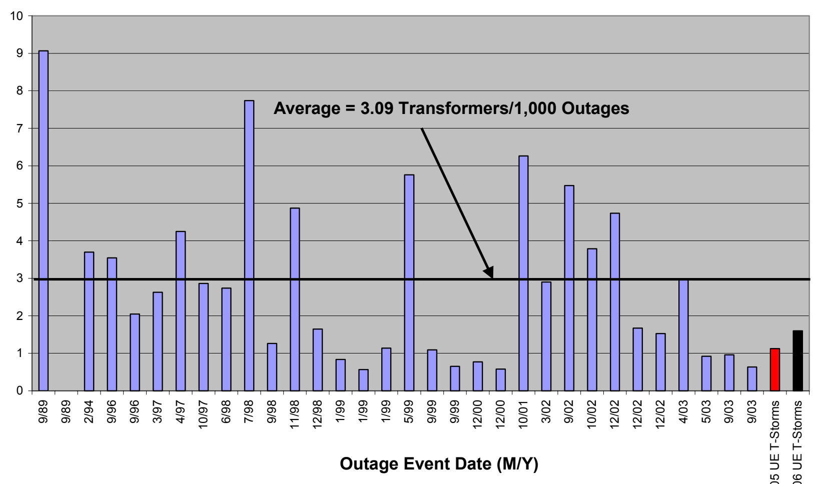


In response to concerns about poorly maintained infrastructure contributing to the extent of damage to AmerenUE's system, Staff looked at the number of broken poles, transformers and conductor miles that had to be replaced per 1,000 customers experiencing an outage. The following three graphs show that AmerenUE's system experienced a lower than average frequency of broken poles, damaged transformers and replaced conductors associated with this outage restoration effort.

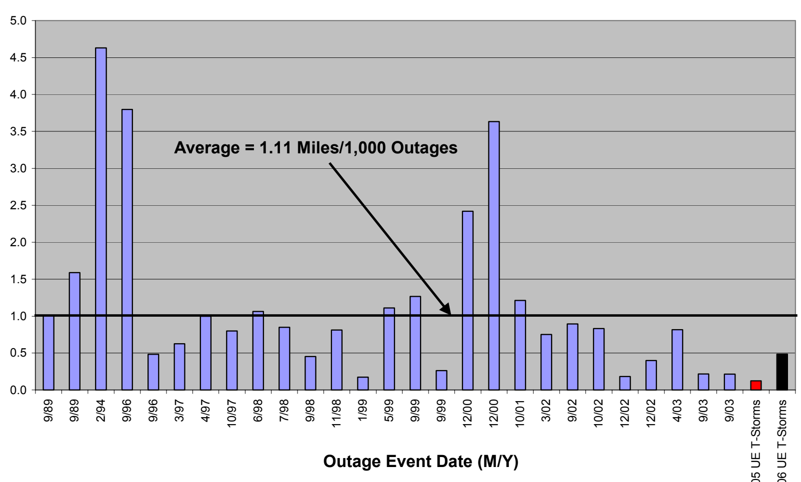
Poles Replaced per 1,000 Customers Out



Transformers Replaced per 1,000 Customers Out



Miles of Conductor Replaced per 1,000 Customers Out



Based on these comparative studies and the content of AmerenUE's EERP versus best practices documents, Staff believes that AmerenUE's response to this outage event was well executed. This finding does not however mean that AmerenUE has adequately hardened its system to reduce the extent of outages from major storms. In this report Staff has provided several recommendations regarding additional programs to reduce the impact of future storms on AmerenUE's system.

Staff believes that in order to bring all the electric utilities in Missouri up-to-date on best practices regarding storm restoration planning and execution a roundtable is appropriate.

Recommendation: Staff should conduct a roundtable with all the electric utilities in Missouri to discuss best practices in restoration planning and execution.

For additional information on AmerenUE's major outage planning process and how they restore power, go to the following link:
(http://www.ameren.com/Outage/ADC_RS_StormCenter.asp)

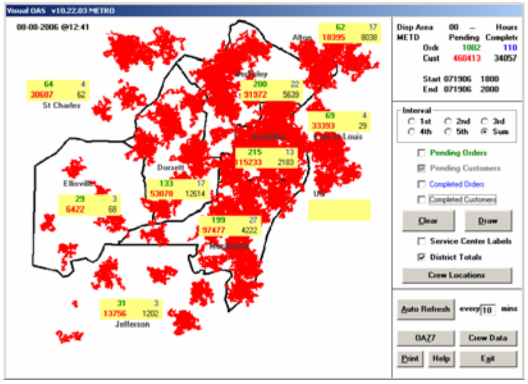
Storm Center Operations & Outage Tracking

Just as in the storms of 2004 and 2005, AmerenUE utilized its Outage Analysis System (OAS) to track and coordinate restoration of outages. However, the number of outage orders created by the storms this year was approximately 14,800 compared to 6,800 in the 2005 storms and 6,900 in the 2004 storms. AmerenUE managed the restoration effort from its EOC by coordinating the callout of crews from other districts and the scheduling and delivery of necessary resources. Local managers directed the response in the field.

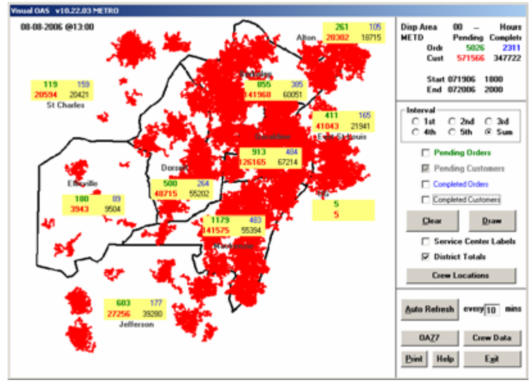
The OAS provided the electronic capacity for the storm coordinator to manage the restoration. Input to the OAS included information from the Call Center from customers and electronic information from the CellNet automatic meter reading (AMR) system. The OAS groups the information from various sources, estimates where the system fault has occurred, and provides this information to the service crews to speed the restoration of service. The ability of OAS to identify likely faults in the system, and extensive utilization of troublemen in the field, was essential for identifying and prioritizing work crew assignments.

Work orders are sent to laptop computers in the service trucks where they are accepted by the servicemen and cleared when completed. One new technology in the OAS system that was being tested in the 2005 storm response and was again used in response to the 2006 storms was the use of voice recognition technology by field checkers when they called in information from the field. This technology is in its roll-out phase and is continuing to be developed.

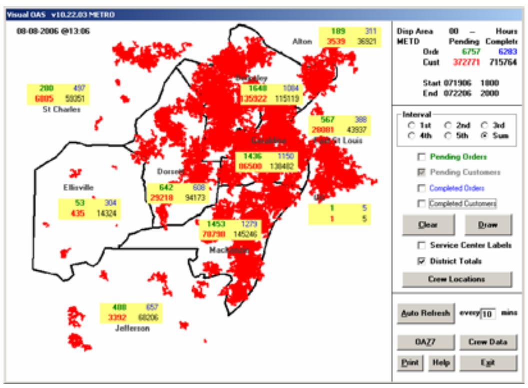
The OAS also has the ability to produce graphical representations of areas where customers are currently without service and where customers have recently had their service restored. The images on the next two pages are from AmerenUE's OAS. They show the areas where customers experienced outages and the period over which service was restored to all customers.



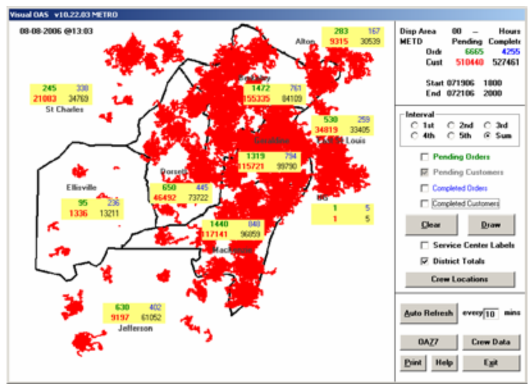
July 19, 2006 8 PM



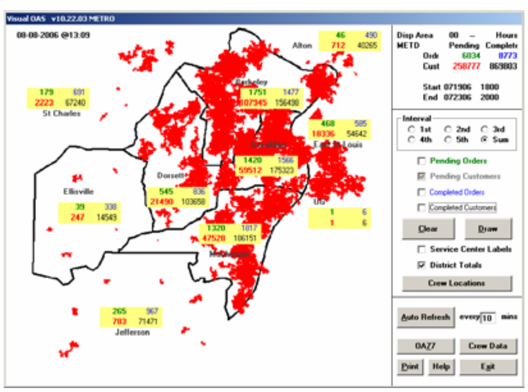
July 20, 2006 8 PM



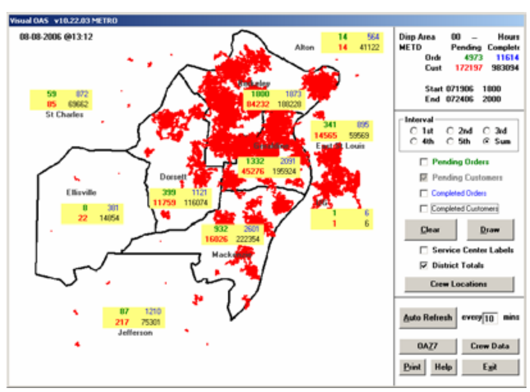
July 21, 2006 8 PM



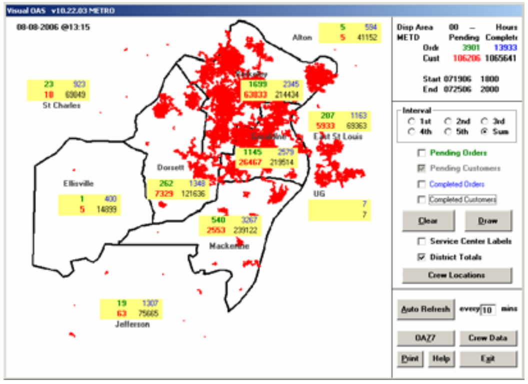
July 22, 2006 8 PM

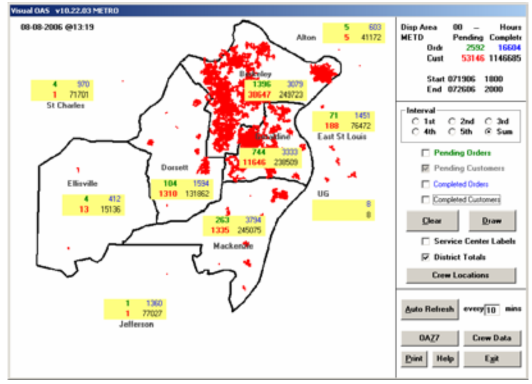


July 23, 2006 8 PM



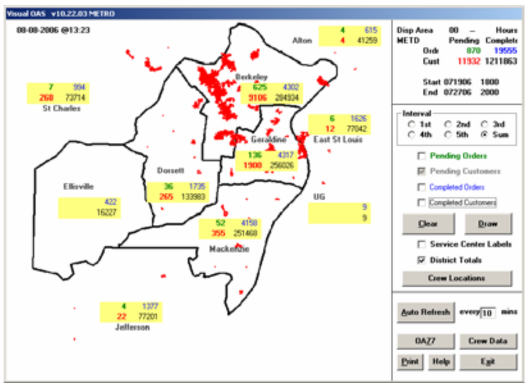
July 24, 2006 8 PM

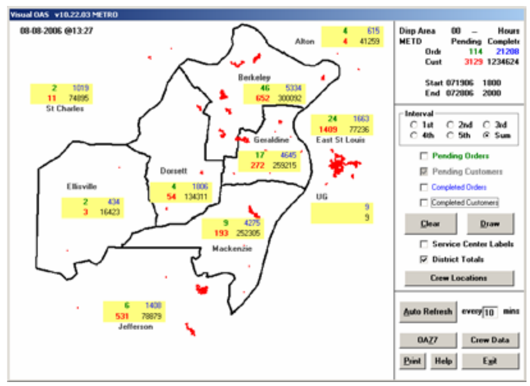




July 25, 2006 8 PM

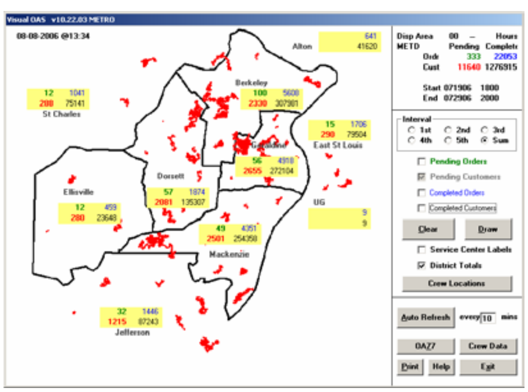
July 26, 2006 8 PM

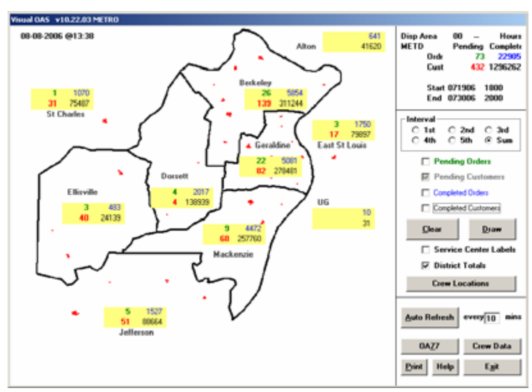




July 27, 2006 8 PM

July 28, 2006 8 PM

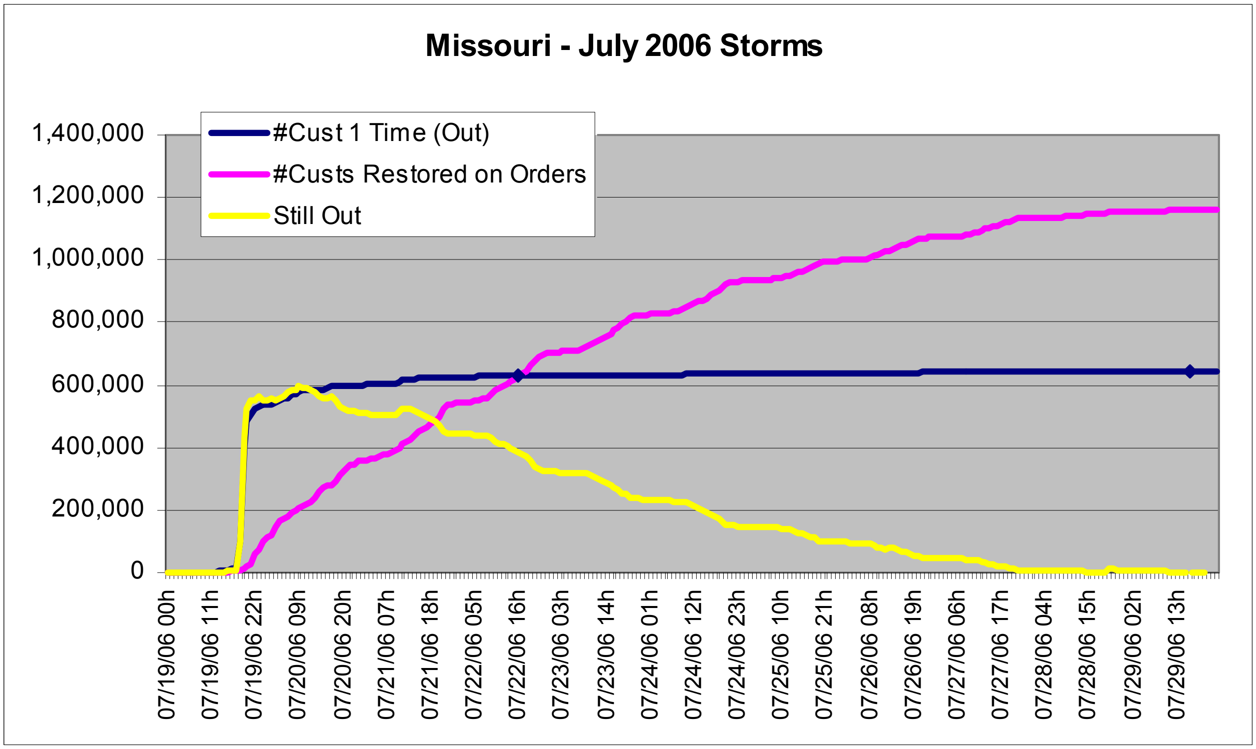




July 29, 2006 8 PM

July 30, 2006 8 PM

The following graph illustrates the rate of restoration following these storms on a total Missouri system basis (from Ameren OAS):



The difference in customer numbers between the "# Custs Restored on Orders" versus the "# Cust 1 Time (Out)" lines illustrates the number of customers that were impacted by more than one damaged element that needed to be repaired before their service could be restored. In an outage event of this magnitude it is relatively common to observe that many customers were actually prevented from receiving power by multiple faults between them and the substation they usually receive power from.

During this outage restoration effort some customers asked for data regarding the outages by County. Peak numbers of outages by County in Missouri are provided in the table below:

State	County	Total
MO	FRANKLIN	17,944
	JEFFERSON	48,720
	SAINT CHARLES	59,200
	SAINT FRANCOIS	18,071
	SAINT LOUIS	351,800
	SAINT LOUIS CITY	121,323
	WASHINGTON	10,140
	Counties w/less than 5000 out	18,348
MO Total		645,546

AmerenUE began calling out its own linemen and field resources at approximately 6:40 PM on July 19th. The Mutual Assistance Agreements section of this report provides details on the number of personnel activated and time frame over which they arrived. Staging sites for three of the Missouri material trailers had been set up and the trailers had been deployed within hours of the passing of the storm with a fourth set up at a later date. Field checking resources and wire watchers were activated at 9 PM on July 19th.

In interviews with AmerenUE they indicated that the restoration effort following these storms consumed approximately five months of common line hardware. In the days following the July 19th and 21st storms, in Missouri and Illinois Ameren installed 1,551 utility poles, 1,515 transformers, 400 miles of wire and cable and approximately 156 miles of electrical tape.

The crews working this restoration generally worked from 5 AM to 11 PM. Some crews did however sometimes work through the night. Crews were not released by Ameren until all work was assigned and remaining crews would not have been productive. A few crews were, however, recalled by their own utilities and left in the final days of the restoration effort before their release by Ameren.

In addition to the linemen, troublemen and tree clearing crews, AmerenUE has checkers/damage assessors, public safety advisors (PSAs) and crew guides in the field. The field checkers typically went out in advance of the tree crews to determine what types of crews and equipment were needed in each area so that AmerenUE's resources could be used most efficiently. The PSAs had many duties, helping wherever possible, including relieving policemen guarding downed wires so that the policemen could be used elsewhere.

While the use of field checkers helped AmerenUE utilize its resources better, it often confused the public because they saw utility personnel come to their area and then leave without doing anything to restore power. Even after the field checkers make their assessment, it may be hours or days before the appropriate crews return to get power restored to these customers. This sometimes results in angry customers who believe that AmerenUE did little and was very inefficient. In fact, AmerenUE was assessing the situation to see how best to restore power to all its customers. For each of the three major storm events of the last three years, AmerenUE increased the number of field checkers and found them very beneficial to the process of restoring customers' service.

Prioritization of repairs is an issue brought up in any major outage restoration effort. The effort following the storms on July 19th and 21st was certainly no exception. AmerenUE's restoration plan is structured to restore the greatest number of customers in the minimum period of time. Without any other influences, this plan would likely restore the "average" customer in the minimum period of time possible. Other influences do however result in outage extensions to the average customer without power. These influences can be described as life, health and safety priorities.

In meetings and interviews with AmerenUE personnel the issue of restoration prioritization was discussed several times. AmerenUE provided Staff with the following description of its restoration prioritization:

- Large transmission lines, sub transmission lines, and substations receive top priority.
- Hospitals, major police and fire stations, public works facilities are restored next along with the backbone feeders, carrying the power from the substations to the customers.
- Ameren makes repairs that will restore the greatest number of customers at one time – in this order:
  - Lines serving large blocks of customers
  - Lines serving neighborhoods with multiple customers
  - Individual services are restored last because fewer customers are involved
  - During the storm, a customer could be affected by just one problem or a combination of problems. All problems affecting that customer must be corrected before electricity can be restored – a situation that can extend restoration times.

During the course of Staff's review, questions about the restoration priority for several specific customer types were raised. For the group that is listed in AmerenUE's second bullet point above, several specific customer types that were discussed were nursing homes and care facilities, mental health facilities, municipal water pumping facilities, and telecommunication facilities. In addition, there were discussions regarding fuel refineries, cooling centers and gasoline stations. The following is a brief summary of Staff's impression of the issues related to prioritization of each of these types of facilities:

Nursing Home Facilities and Care Facilities – this customer type was identified in the recommendations in Staff's 2005 Storm Report. AmerenUE is continuing its effort to address the needs of this customer type. The first step in this process is to identify the various facilities' locations and use GPS technology to overlay service territory by facility category and determine impact to response based on recent storms. This topic is discussed in more detail in the section addressing AmerenUE's compliance with each of the Staff's previous recommendations in the 2005 Storm Report.

Mental Health Facilities – This customer type actually involves two distinct facility types: group home facilities and large complex facilities. The Staff believes that AmerenUE should participate in the SEMA/EOC coordination phone calls as one step towards insuring that AmerenUE is kept informed of the needs of this customer type. However, the Staff notes that many of these group home facilities are in residential neighborhoods not near a feeder and AmerenUE may not be able to reasonably provide priority service to these facilities without significantly impacting average customer restoration rates.

Municipal Water Pumping Facilities – From Staff's perspective, the concerns raised regarding this customer type were sometimes due to problems communicating the needs to AmerenUE's EOC and not to AmerenUE's response once this need was identified. Several Staff recommendations in this report regarding communication should improve this situation in the future.

Telecommunication Facilities – This is discussed in the "Other Utility Impacts" section of this report.

Fuel Refineries – Although concerns were raised regarding a refinery in the St. Louis metropolitan area, Staff understands that power was restored to the facility relatively quickly. However, the facility was damaged by the storm and therefore did not return to production before AmerenUE completed its storm restoration efforts for all of its customers.

Cooling Centers – Although AmerenUE had direct lines of communication to various city and county officials, others raised concerns about the restoration priority given to cooling centers. Several recommendations in this report regarding communication may help in the future in this area. However, the Staff observed that the locations of some cooling centers, away from substations or feeders, limited AmerenUE's ability to quickly restore their power.

Gasoline Stations – The large number of these types of facilities and the number of them that are not located close to feeders makes it difficult for AmerenUE to effectively prioritize these facilities. A requirement to prioritize these facilities could significantly impact average customer restoration rates on a system-wide basis.

Downed Lines – Staff was made aware of numerous downed wires during this restoration effort. Several comments at the public hearings in this case related to downed wires being energized for significant amounts of time after the storms had passed.

Relative to these particular customer types, Staff does not believe that the most appropriate course of action is to issue a broad edict that requires that all of these facilities always receive priority restoration of service. Some of these facilities are redundant in nature and some of them have back-up generation to serve them for a period of time. Staff suggest that it may be more appropriate that AmerenUE instead actively participate in the SEMA/EOC coordination meetings following major outages and prioritization of particular facilities in need be established in these meetings as was done this year following the storms on July 19th and 21st. Staff does however recommend that additional measures be taken to make downed lines safe.

Recommendation: AmerenUE should continue to enhance its safety programs to identify and make downed lines safe after a major outage event.

Mutual Assistance Agreements

Ameren is a member utility to two mutual assistance organizations. These organizations are the Edison Electric Institute (EEI) assistance organization and Midwest Mutual Assistance (MMA) organization. The EEI assistance organization includes most of the investor-owned electric utilities in the U.S. The MMA organization consists of approximately thirty member electric utilities that stretch from Michigan and Minnesota in the north to Texas in the south. It ranges from Kansas to the west and Indiana on the east. The MMA is divided into three geographic zones. Once a utility determines that it needs assistance, it begins its request with calls for help to utility members in its zone. The map below was provided by AmerenUE and shows the stretch of this mutual assistance organization and the three zones. The utilities in each zone are close enough in proximity so that assistance can reach the other utilities in the zone quickly when there is a call for assistance. AmerenUE is situated in the middle of Zone #2.

The first series of severe thunderstorms hit the northern St. Louis area at approximately 6:20 PM on July 19th. The initial call for AmerenUE crews was made at 6:40 PM when the emergency response plan was initiated. As the level of damage to AmerenUE's infrastructure mounted, another call was made at approximately 8:30 PM for all remaining Ameren (both Missouri and Illinois) crews. The calls to mutual assistance partners within the MMA group began soon after that. Initially the response from other utilities was limited due to the storms that went through the Midwest earlier in the week, the forecast for unusually hot weather to continue to set demand peaks, and the potential for more severe weather in the Midwest. Severe storms that went through the Midwest the previous Monday resulted in power outages in Michigan, Illinois, Indiana and Wisconsin.

The weather forecast was for extremely hot temperatures in the Midwest to continue on July 20th and for the heat wave to end on July 21st with the arrival of a cold front and the potential for additional severe weather. This was the cold front that contained the severe storms that hit the St. Louis region on July 21st. When initially contacted, utilities were reluctant to send all of their available crews to Ameren as long as a good possibility existed that they would need their own crews to restore power in their own territories. While there was a limited initial response to these requests for assistance, requests by Ameren on July 19th and July 20th were generally not successful.

Requests for assistance continued and, after the cold front that spawned the additional severe storms in St. Louis on July 21st moved through each utility's region, crews that had not previously been released from other utilities began making their way to the St. Louis area. These crews arrived in the St. Louis area late on July 21st and early on the 22nd.

Utilities from twelve states including Kansas, Missouri, Iowa, Ohio, Mississippi, Louisiana, Texas, Arkansas, Illinois, Indiana, Michigan and Kentucky, sent crews to help. They included the following utilities.

Utility	State	Utility	State
Westar	KS	Detroit Edision	MI
Indianapolis Power & Light	IN	E On US (LG&E)	KY
KCPL	MO	AmerenIP	IL
Empire District Electric Company	MO	AmerenCIPS	IL
Mid-American Energy Company	IA	Vectron Energy	IN
American Electric Power (AEP)	OH, OK	Aquila	MO
Entergy	MS, LA, TX, AR	City Water Power & Light, Springfield IL	IL

Duke, Oklahoma Gas & Energy, Northern Indiana Public Service Company, Alliant and Commonwealth Edison were also contacted but were not able to provide assistance. Utilities in Baltimore, San Diego and Arizona offered to send crews. However, these offers did not come in until the Tuesday and Wednesday the week after the first storm. At this time, AmerenUE decided not to accept their offers since it would have taken these utilities' crews at least one to two days to arrive in the St. Louis area and by that time most of the restoration work would have been done.

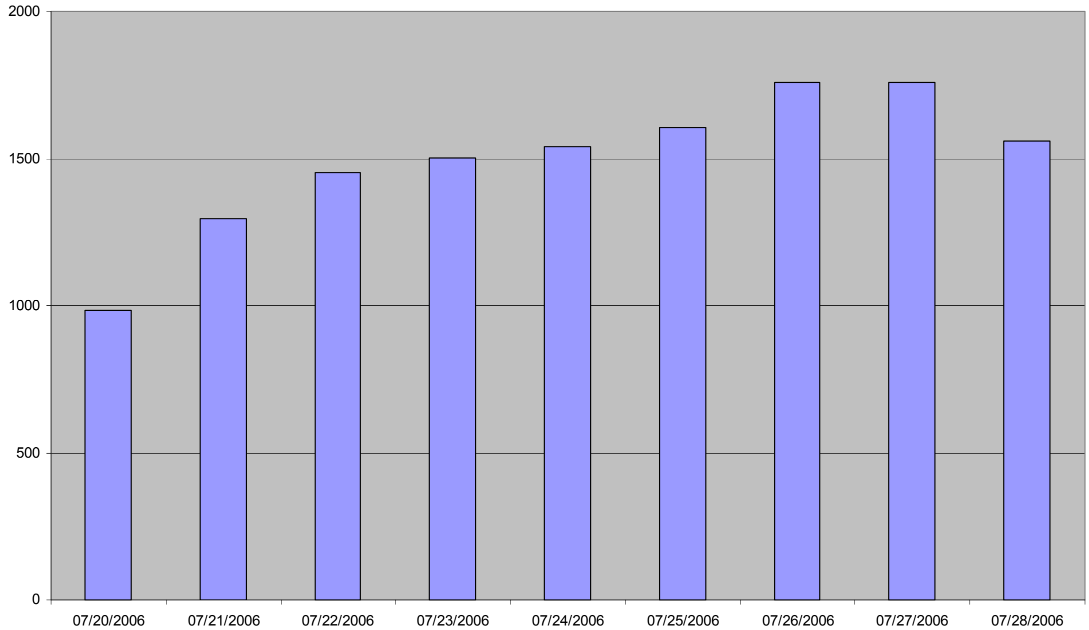
In this restoration effort Ameren, for the first time, received help from the surrounding rural electric cooperatives. Twenty-two of the cooperatives responded with linemen supporting the restoration effort. AmerenUE had more linemen working this outage than it has had in any previous outage. The table below indicates the number of linemen that worked this outage.

Ameren Linemen	458
Contractor Linemen	960
Cooperatives Linemen	97
Mutual Assistance Linemen	296
Total	1,811

The contract linemen were not just linemen that had contracts with AmerenUE, but also linemen that were released from their contracts with mutual assistance utilities to work this outage for AmerenUE. For AmerenUE and other utilities, more and more of the every day field work is now done by contract labor. When this storm hit, AmerenUE called, requested and received, neighboring utilities' release of their contract crews so that AmerenUE could use them to help with the storm restoration.

The graph below shows the total number of linemen resources that worked the outage in Missouri. It shows a little less than 1,000 linemen were working in Missouri on July 20th. That number jumped to about 1,300 on July 21st and reached its maximum of 1,811 on July 26th, a week after the first storm. On the last day of the storm restoration effort, there were still over 1,500 linemen working on AmerenUE's infrastructure.

Total Lineman Resources in Missouri by Day of Outage:



Electric service would not have been restored to many areas as soon as it was without the help that AmerenUE received from mutual assistance agreement utilities and the electric cooperatives. In addition, twenty-five electrical construction contractors sent crews to help out AmerenUE.

The table below gives the total count of all resources working this major outage event in Missouri:

Ameren Linemen	458
Contractor Linemen	960
Co-Op Linemen	97
Mutual Assistance Linemen	296
Tree Clearing Crews	833
Customer Service Reps	175
Field Checkers/Damage Assessors	230
Other Field Forces	211
Crew Guides/Clerical Support	110
Stores/Material Management	55
Distribution Dispatch/EOC Staff	55
Crew Supervision/Crew Dispatch	105
Fleet Services	35
Safety Professionals	30
Logistics Support	150
Total	3800

For Missouri and Illinois in total approximately 5,300 personnel were deployed.

The Staff strongly supports AmerenUE's continued participation in mutual assistance agreements and has the following recommendations in this area:

Recommendation: AmerenUE should continue to maintain its mutual assistance agreements, and in each major restoration effort evaluate the necessity of utilizing these agreements so that it will have access to such resources when needed.

Recommendation: AmerenUE should explore the structure of a mutual assistance agreement with the Association of Missouri Electric Cooperatives (AMEC) for future emergencies where either AmerenUE or one or more of the electric cooperatives needs assistance following major storms like those experienced on July 19th and 21st.

During the public hearings associated with this case a number of witnesses stated that in their conversations with crews from other states it was observed that some of these crews did not have current maps and did not appear, at times, to know where they were going or how to get there. In the Potosi public hearing these maps were referred to as “911 maps.”

Recommendation: AmerenUE should either maintain or have the ability to produce up-to-date maps of its infrastructure and roads to supply to crews during major outage events.

Vegetation Management

In previous Staff electric utility restoration investigations, vegetation management was one of the issues dealt with at length. Vegetation management is the electric utility's program for systematically clearing vegetation from its transmission and distribution facilities in compliance with National Electric Safety Code (NESC) requirements. Many utilities perform vegetation management in accordance with American National Standards Institute, Inc. (ANSI) Standard A300. AmerenUE follows ANSI A300 and NESC in its vegetation management program. Link to ANSI A300 – 1995: (http://www.co.palm-beach.fl.us/erm/protection/Images/PDF_Documents/ansi.pdf)

In the Staff's report following the 2004 storms, the Staff made the following recommendation:

> Staff strongly recommends that AmerenUE immediately implement programs to begin addressing the existing backlog in the tree trimming cycles of its distribution systems in rural and suburban areas. AmerenUE's efforts to address this current backlog in distribution system trimming should not be implemented through any types of reductions in current efforts to adequately control vegetation along their transmission system corridors or in reductions in efforts in other areas that could impact system reliability or safety. Staff notes that AmerenUE has policies currently in place regarding vegetation management, working with impacted landowners and public relations. AmerenUE should not diminish or stop applying any of these customer relation polices or practices in its efforts to address this current backlog in tree trimming work.

After discussions between AmerenUE and Staff, AmerenUE made the following commitment in a letter dated November 2, 2004:

> AmerenUE's goal is to have tree trimming cycles for its Missouri distribution systems of four years growth for urban areas and 6 years growth for rural areas. However, as the Staff report recognized, the Company has experienced extended tree trimming cycles. Moreover, the limited availability of properly trained tree trimming crews to contractors makes it virtually impossible to immediately eliminate the backlog. AmerenUE has discussed this issue at length with the Staff and has agreed to take the following steps to address the backlog. First, AmerenUE will increase its tree trimming budget from $23.5 million in 2004 to $30 million in 2005 – a 27% increase. This step will allow the Company to

> immediately direct its vegetation management contractors to begin the hiring and training of new tree trimming personnel. Second, AmerenUE commits that its backlog of extended tree trimming cycles will be eliminated on or before December 31, 2008. AmerenUE anticipates that meeting this commitment will require expenditures at or near the $30 million level for each of the next several years. Third, the Company will provide reports to the Staff of tree trimming schedules, staffing and funding levels. For 2005, the Company will provide these reports on January 15 and July 30, and thereafter the Company will also make its vegetation management personnel available to review these reports with the Staff, at the Staff's request. Fourth, the Company is willing to participate in joint field reviews of the program with the specifics of the field review to be developed in cooperation with the Staff.
>
> AmerenUE's efforts to address its distribution system tree trimming, as outlined in the previous paragraph, will not be implemented through any type of reduction in the Company's current efforts to adequately control vegetation along its transmission system corridors or in reductions in efforts in other areas that could impact system reliability or safety. In addition AmerenUE will not diminish or stop applying any of its current customer relation policies or practices relating to vegetation management in its efforts to address system tree trimming.

As AmerenUE's commitment indicates, AmerenUE has begun the process of reducing its tree trimming backlog. However, even if AmerenUE had totally eliminated its tree trimming backlog last year, most of the tree related outages observed following the storms on July 19th and 21st would have still occurred.

One common misconception is that vegetation management programs are structured to significantly reduce the extent of damage to the electric utility's transmission and distribution infrastructure during major storms. While this is true for right-of-way (ROW) corridor vegetation clearance programs along transmission lines, this is generally not true for sub-transmission and distribution lines. Transmission lines serve many thousands of customers and are accordingly "hardened" against damage from all forms of severe weather other than tornadoes, extraordinarily powerful hurricanes and abnormally severe ice storms.

A quick review of the width of the ROW and level of vegetation clearance along a transmission line attests to the importance of these lines. A quick comparative review of trimming along sub-transmission or distribution lines vividly illustrates the differences between vegetation trimming along these lines versus transmission lines.

Any drive through St. Louis along a distribution line running through a heavily wooded area will quickly demonstrate to the observer that AmerenUE's vegetation management program does little to address large trees and limbs that pose a real outage risk in a major storm. This is because AmerenUE, like many electric utilities, trims along its lines to reduce the frequency of incidental contacts between power lines and limbs during regularly experienced winds. This type of vegetation program is designed to improve day-to-day reliability.

Staff continues to believe that AmerenUE can improve the reliability of its service to customers through a well-executed vegetation management program and this has been the basis for its past recommendations in this area. Unfortunately, based on the news articles Staff has reviewed on this subject and the testimony of many of the witnesses at the public hearings in this case, the importance of this topic versus other storm restoration issues appears to have been overemphasized. While the vegetation management programs of AmerenUE can improve day-to-day reliability, in their current form, they will not significantly reduce the severity of outages following major storms.

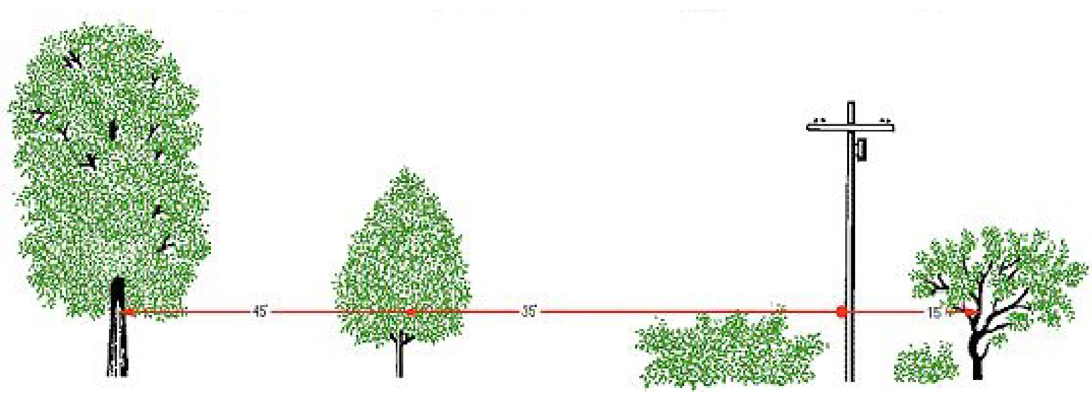
Recommendation: AmerenUE should continue to work toward elimination of its trimming backlog per its prior agreement with the Staff in Case No. EW-2004-0583.

In the November 2005 edition of Transmission and Distribution World magazine, Ward Peterson of the Davey Resource Group gives some information on tree caused outages in the article titled *Electric Reliability and Outages*. In this article Mr. Peterson states:

> Just pruning trees away from lines will not stop all the outages. Several studies conducted by experienced right-of-way managers across the continent have shown that trees growing into power lines actually caused less than 14% of the outages for all utilities contacted. The data further showed that trees that fall into the lines – often from outside of the right of way – cause 66% to 94% of the outages.

Following the August 2005 storms, AmerenUE's vegetation management field forces estimated that eighty to eighty-five percent of all tree damage was from trees located off of the easement. These statistics are not surprising given almost all service lines are not on easements and easements for most distribution lines are quite narrow relative to the tree growth heights around them.

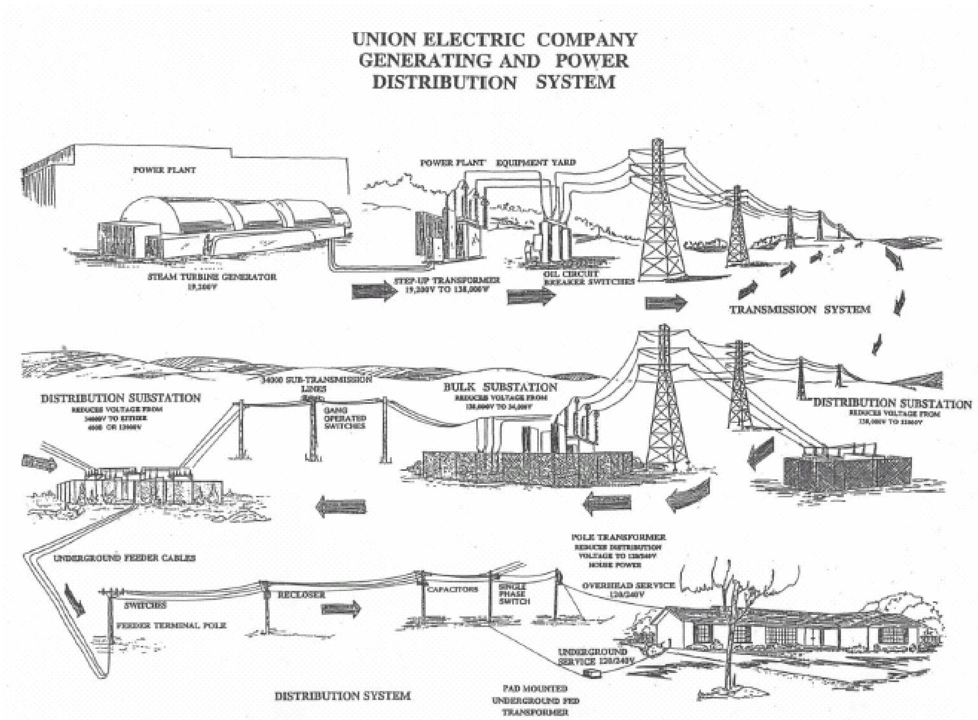
AmerenUE's website on planting the right kinds of trees in the right place includes the diagram below. Link to this website:
http://www.ameren.com/Environment/ADC_EV_TreePlantingTips.asp



Unfortunately, many of the trees growing along the power line ROW corridors in the St. Louis area do not look anything like this diagram. In the areas particularly hard hit by the major storms in 2004, 2005 and this year, Staff has noted at least one consistent factor.

This factor can be described as heavily wooded areas with large old-growth trees and trimming along sub-transmission and distribution lines that does little to reduce the damage to lines from large limbs and trees during major storms. Staff has been in discussions with AmerenUE and conducting its own research on possible approaches to deal with this situation.

The following diagram illustrates the major elements of the infrastructure that AmerenUE depends on to deliver electricity to its customers including service lines and distribution lines:



Service lines typically operate at 240 volts, are covered, and can therefore tolerate incidental tree contact. Customers typically do not pay any attention to tree limbs that are near or even touching service lines since they still receive service under most conditions. However, these same limbs and trees can do significant damage to a service line if the full weight of the limb or tree is forced upon the service line, which often happens during severe storms.

Distribution lines, such as a primary conductor that is typically 7,200 volts, are not insulated. Contact with tree limbs can cause arcing or electrical short circuits to ground. Typically, the easements for the distribution lines define the corridor in which the trees are trimmed. Many single-phase lines are in a ten foot easement while three-phase lines may have a twenty foot easement. This means that many limbs are no more than five to ten feet away from the conductor and are often closer. While this distance is adequate under most conditions, during storms like those on July 19th and 21st, the same limbs can damage the distribution conductors.

Much of the focus of this report is on severe thunderstorms and the high winds and lightning they bring. The weather condition that likely represents the worst-case scenario for AmerenUE and the St. Louis area would be an ice storm. Generally, severe thunderstorms are somewhat limited in terms of their regional impacts and work conditions are favorable shortly after the storm. In contrast, ice storms can affect large areas and the ability to respond to an ice storm can also be affected by the road conditions that are often treacherous for several days after the storm hits. The risk an ice storm poses to St. Louis is particularly severe due to the extent of densely wooded areas, the prevalence of tall trees near power lines, the high percentage of lines routed behind houses versus along streets and the extensive overhangs of tree limbs over distribution lines. Finally, the service drops are particularly vulnerable to overhead limbs and to ice forming on the line. Damage to service drops is further complicated when the weatherhead (the pipe assembly rising above the roof where the service line enters the building) is damaged since the weatherhead is owned by the customer and therefore must be repaired by the customer's contractor.

In order to provide for consistent oversight capability and comparative analysis, Staff believes that implementing a vegetation management reporting rule is appropriate at this time. While Staff has access to this information and reviews it as case issues require, little consistency of data is currently available for assessing electric utility planning, or for determining electric utility best practices, in this area. Staff has found that states that have vegetation management reporting rules were in a better position to assess their utilities' vegetation management programs' structures and outcomes. A draft rule that would accomplish this is attached in Appendix D.

Recommendation: Adopt and implement a Commission rule to require each electric utility to annually submit a report on its vegetation management program's structure, objectives, status, and funding.

In assessing AmerenUE's vegetation management program, Staff has concluded that while the current program will improve day-to-day reliability over time, the current program will not likely result in the storm restoration improvements customers are requesting. Relatively few options exist to achieve the objectives that are being pursued. One of these options is to bury much larger portions of AmerenUE's system. While this may at first appear to be a reasonable solution, Staff has observed that this option is more expensive, especially for higher voltage applications. While this expense could be justified if it resulted in less replaced infrastructure over time, Staff has observed other problems with this approach. In places where existing overhead lines have been buried complaints have been voiced about trenches through gardens and landscaping, killed trees and the additional per house expense of going to an underground service line and riser.

Further, while burying distribution lines does appear to help with the frequency of outages, it often results in an increase in the duration of outages. Staff has investigated several informal complaints regarding long outages on buried circuits. Overhead line faults are much easier to identify and fix than underground line faults. Nonetheless, Staff does believe that current practices for contractors and homeowners to request, and pay for, buried services should be continued as this is the most equitable means to be provided with underground service if a customer wants it. Also, under certain circumstances in areas with particularly high tree related outage histories, burying the infrastructure may still be a viable option that should be considered.

If the current vegetation management program will not provide the storm restoration improvements that are desired and burying large portions of AmerenUE's circuits is not practical, the remaining options are clear. Staff believes that AmerenUE should implement programs to more thoroughly clear trees in its ROW and pursue removal of problem trees off its ROW along its backbone systems. It is also appropriate for AmerenUE to look at trimming areas with particularly dense growth on a more frequent basis.

If these programs are implemented it will be essential that AmerenUE also implement programs to educate the public on why these programs are being implemented and the benefits customers can anticipate as a result of these programs. It will also be essential that AmerenUE's vegetation management contractors work with customers to the greatest degree possible, consistent with still achieving the trimming required, as this trimming program will result in a lot of large trees along backbone systems either being severely trimmed or removed and possibly replaced with smaller ornamental trees.

Recommendation: AmerenUE should implement vegetation management programs that:

a) **Target more substantial removal of vegetation along power lines throughout its system, including side clearances and overhangs, along feeders and sub-transmission systems.**
b) **Target removal of problem trees within the utility's easement and possible replacement with ornamental trees or other low-growing vegetation.**
c) **Target communications with landowners, who have trees off the right-of-way that represent a significant risk to sub-transmission and feeder lines, to find reasonable means to reduce the outage risk from these trees.**
d) **Trim trees in areas with particularly high densities of vegetation on a more frequent basis. Currently urban areas are targeted for a four-year cycle; it may be appropriate to go to a three-year cycle in some areas.**

For a thorough discussion on how higher reliability can be achieved through vegetation management the reader is encouraged to read the following articles in the November 2005 edition of Transmission and Distribution World magazine:

"*BGE Transforms Vegetation Program*", by William T. Rees Jr.

"*Investigating Tree-Caused Faults*", by John Goodfellow

"*Electric Reliability and Outages*", by Ward Peterson

Call Center Operations & General Consumer Communications

Ameren provides customers with an 800 number to contact its Call Centers (also referred to as Contact Centers) for a variety of services and questions. St. Louis metropolitan area customers may use local numbers for outages and billing. Under normal conditions, all calls will go to one of the three Company operated Call Centers located in St. Louis, Jefferson City and Cape Girardeau.

When the customer dials the 800 number, the customer first reaches the Voice Response Unit (VRU) which helps to categorize their call and route it to the next appropriate group of options available to handle the request. Based upon the nature of the call, the customer will be able to select the option that can most quickly handle the call. During the hours of 7 AM to 7 PM Monday through Friday, there are four options available for the customer's inquiry.

The first option is to report an outage or gas leak. The second option is billing because of the frequency of these calls. In this instance, because of the large number of calls being received, the Company added a script to its up front message. The message encouraged customers that had a billing issue to call back on Monday because of the volume of calls being received on the outage.

When the customer elects to report an outage, the customer is then given three options. The first option is if there is a "light out" to report. "Light out" asks the customer to input a phone number. The system then looks for a match and asks the customer to verify whether the information is correct. If there have been enough "light out" calls entered into the system for it to make some determination of the extent of the outage, then the customer will, under some circumstances, be given information on the number of customers affected and the estimated restoration time (ERT). ERT is calculated using an algorithm and is discussed in greater detail later in this report.

At any time, if the customer does not provide the requested information, the call will be transferred to an agent. The second option is if there is a wire down or gas odor. These calls go straight to an agent. The third option is if there is a streetlight out or other outage. This option also asks the customer to input a phone number.

If the customer has opted to speak to an agent, the representative will take the information and enter it into the trouble screen. The representative can let the customer know if the specific cause has been identified (i.e., feeder is out), whether a crew is assigned to the outage, and the approximate number of other customers affected. As field checkers are able to assess the specifics and extent of damage, they are able to make a determination regarding the actual repairs needed and the relationship of this repair to others pending. As a crew is assigned, they are required to enter an estimate of restoration time for this job. Service representatives taking calls from the customer are able to access this information.

The Company staffs its Call Center based upon historical levels of calls at various times of the day, week and month. However, when a major outage occurs, the normal level of resources will be unable to process the volume of calls that may occur. There are a number of options available to AmerenUE regarding how to increase its call handling ability under high call volume situations.

The first option is the utilization of additional telephone trunk lines to accept outage calls. AmerenUE subscribes, as many other companies do, to a service that allows it to access additional telephone trunk lines in the event of an emergency that presents it with a high volume of calls. If the number of calls going to the VRU reaches its maximum volume, additional trunk lines are automatically accessed from NNC (the private company that provides trunk line service).

Overflow outage calls accessed additional telephone trunk lines starting on July 19th, the day of the first severe storms, and continued through July 28th. For that period of time, the NNC overflow took a total of 267,233 calls. The first three days of the storm were the most significant. Over 219,000 calls were handled by the NNC overflow in that timeframe. These outage reports were automatically entered into the outage system to be worked in the field.

The following table illustrates the call volume received by the Company and handled by the VRU and the NNC overflow during the period of July 19th through July 28th:

Call Volume Received

	7/19	7/20	7/21/	7/22	7/23	7/24	7/25	7/26	7/27	7/28
VRU orders (outage only)	2,220	45,682	38,491	36,586	29,516	20,690	16,267	13,029	8,329	4,682
NCC Overflow	60,241	94,070	64,857	19,127	8,269	13,613	3,100	2,387	177	1,392

The Company received a greater number of calls during the course of this outage restoration as compared to the storms in 2004 and 2005. The total number of calls for the major 2005 outage was 278,863 compared to this year's major outage where the Call Center handled 715,689 calls over a ten day period.

Another option available to AmerenUE was to reallocate some of its present resources, which may normally be used for handling billing inquiries or credit and collection calls, to taking outage calls. The Company utilizes First Contact which is an outside contractor to assist it by handling customer calls involving payment arrangements and delinquent accounts. An actual service representative who can access the Customer Information System (CIS) responds to these calls. AmerenUE is able to request that First Contact assist in these situations by accepting outage calls, instead of handling billing inquiries. When the call volume rose on July 19th, the Company brought First Contact in to also accept outage calls. First Contact handled calls on July 19th through July 22nd and then assisted again on July 24th through July 28th.

On a normal weekday, an average of 115 representatives takes calls at the AmerenUE Call Center. On July 20th the Company also enlisted the assistance of service representatives from AmerenCIPS and AmerenCILCO to start receiving outage calls as it was obvious there was widespread storm damage and all available representatives were needed. The AmerenCILCO and AmerenCIPS agents assisted in handling calls until July 24th. The following chart shows the number of personnel taking calls July 19th through 28th:

Personnel Taking AmerenUE Calls

7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28
162	235	252	166	148	197	188	175	178	157

The number of personnel shown includes AmerenUE employees, AmerenCIPS/CILCO call takers, and employees at the outsourced group. First Contact is the contractor company that normally handles collection related calls for the Company. In instances of widespread outages, the Company may ask them to assist by taking outage calls. Overall, the Company was able to handle a greater number of calls related to these outages through utilization of 1,858 personnel over ten days.

The Staff reviewed the average number of calls per day handled by the Call Center from 2002 to the storms this July. The numbers for the 2004 storms and the 2005 storms represent the average daily number of calls over the period of those outages. The results of Staff's review are provided in the following table for comparison.

Call Center Average Daily Calls

2002	2003	2004	2004 Storms	Jan.-July 2005	2005 Storm	2006 Storm
11,334	9,642	11,050	51,116	10,626	55,772	71,569

The Company was faced with a greater number of calls after these most recent storms than any it had encountered in earlier restoration efforts. In these storms, the Company was able to determine relatively quickly that the system had suffered widespread damage. They incorporated a message within the script to inform the customer that the outage could last three to five days. While the customer would prefer to know a specific time that their service would be restored, the message did alert them to the widespread nature of the outage and encouraged them to take action to move to another location, if possible. Many customers did take this message seriously and moved in with relatives or friends who had power. The Staff believes that these scripts are an important area for Ameren to continue to focus on. They provide a direct way to communicate with the customer who is attempting to determine information about their outage.

The Staff received a number of comments from customers who were attempting to contact AmerenUE regarding billing questions during this restoration effort. Most of these concerns pertained to customers who had delinquent accounts and were scheduled for non-pay disconnection during this time frame. Some customers were confused about whether their service would be shut off during this time frame so they continued to attempt to reach a Call Center representative. As previously noted, Ameren was devoting all of its resources to restoring service to customers. A very clear message within the VRU script could have informed these customers that disconnections due to delinquent payment on accounts are not being performed in specific areas for a period of time. This would allow these customers to receive an answer to their inquiry about disconnections without staying on the line to the Call Center. Service representatives should also be informed of the message on the VRU script so that the customer who does reach a representative receives a consistent message.

Recommendation: AmerenUE should include a clear message within the Voice Response Unit (VRU) script to address non-pay disconnections during the course of major storm outage restorations.

An additional concern during a major outage relates to the wait time experienced by the customer in trying to access the Company's phone lines to report the outage. Call Centers routinely utilize a number of indicators to assist them in determining the level of their performance in providing service to the customer.

The two indicators most frequently cited by companies are the Average Speed of Answer (ASA) and the Abandoned Call Rate (ACR). The wait time that a customer experiences before he/she is able to report information to a service representative is defined as the ASA and is measured in minutes and seconds. The ACR reflects the percentage of the calls that are abandoned or terminated before they are handled often because of long wait times experienced by the customer. AmerenUE utilizes a Percent Answered indicator, which is similar to the ACR. The Percent Answered is the difference between 100% of the calls and the percent of calls not answered or abandoned.

The Company's performance at the Call Center during the period of the 2006 storm restoration effort is illustrated in the following table:

Call Center Performance

	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28
Average Speed of Answer	1:43	1:26	1:32	0:23	0:25	1:32	0:25	0:34	1:09	1:43
Percent Answered	75.6%	82.6%	83.4%	94.6%	95.1%	89.7%	94%	93%	90.2%	82.5%

Information provided in this table represents the performance of all agents working for Ameren during the period of the outage. The Average Speed of Answer during the course of the outage was one minute, five seconds. This compares very favorably with other similar types of metrics from other outages. However, the figures can be a bit misleading and difficult to use in a comparison to other outages due to three specific technical difficulties which occurred to the Company's incoming Call Center lines.

Call Center Technical Issues

Complaints and comments received by the Staff noted a number of instances where customers received busy signals or the lines went dead when they tried to contact the Call Center. In this storm outage, the majority of comments addressed these types of situations as opposed to being put on hold for long periods of time.

The first technical problem occurred on July 19th from approximately 7 PM until 1 AM the next morning. The Announcement Board in the Company's PBX was intermittently locking up due to a software bug and, as a result, was not playing any sort of announcement to the customer. The manufacturer is currently developing the software patch for this and it will be installed and tested shortly. During the interim, the Company is running a script every 6 hours that looks for the characteristics that cause the announcement board to lock up under heavy load.

The second problem had to do with the implementation of "call gapping" by AT&T on July 19th, 20th and 21st on Ameren's primary local numbers. Call gapping is a control application that limits the rate of flow to a specific destination or station address. Without the application of this type of technology, offices can lock up during periods of very heavy call traffic to specific switches and create serious network outages. The calling rate on July 19th was 200,000 calls coming in for a period of two to four hours during the storm. Because of this high volume of traffic, AT&T applied call gapping.

This technology was applied to twenty-six of the twenty-seven St. Louis central office switches by AT&T and only allowed 150 calls per five minute period per switch to be passed to Ameren. All other calls got either dropped or busy signals. Ameren turned in a trouble ticket to AT&T late in the evening of July 19th but were not informed that call gapping had been implemented. Call Center management at Ameren realized that something was wrong and began their own testing of the local outage and billing numbers on July 20th. An additional trouble ticket was turned in to AT&T on July 21st and this was escalated to additional personnel who were to check specifically if Ameren was having calls blocked. Calls were back to expected levels late that evening in the Call Center. The Company was later told that call gapping had been implemented by AT&T.

Ameren and AT&T met on August 3, 2006, to discuss the application of call gapping during the storm outage. The Company has held a number of additional meetings with AT&T to determine how they can work closer on these issues. Ameren has stated that it has requested that AT&T proactively notify the Company when they are going to implement call gapping so that Ameren can notify the public not to utilize these lines. However, AT&T has indicated to Ameren that they could not do that. Ameren is continuing to pursue a solution with AT&T and the Companies are working toward an agreement.

Because of the effect upon the Company's ability to accept and handle customer calls during an outage, the Staff believes it is critical that Ameren be given notification that call gapping has been implemented within a relatively short period of time of it occurring.

Recommendation: AmerenUE should continue discussions with AT&T regarding notification whenever call gapping is to be implemented on switches that affect the provision of critical AmerenUE services.

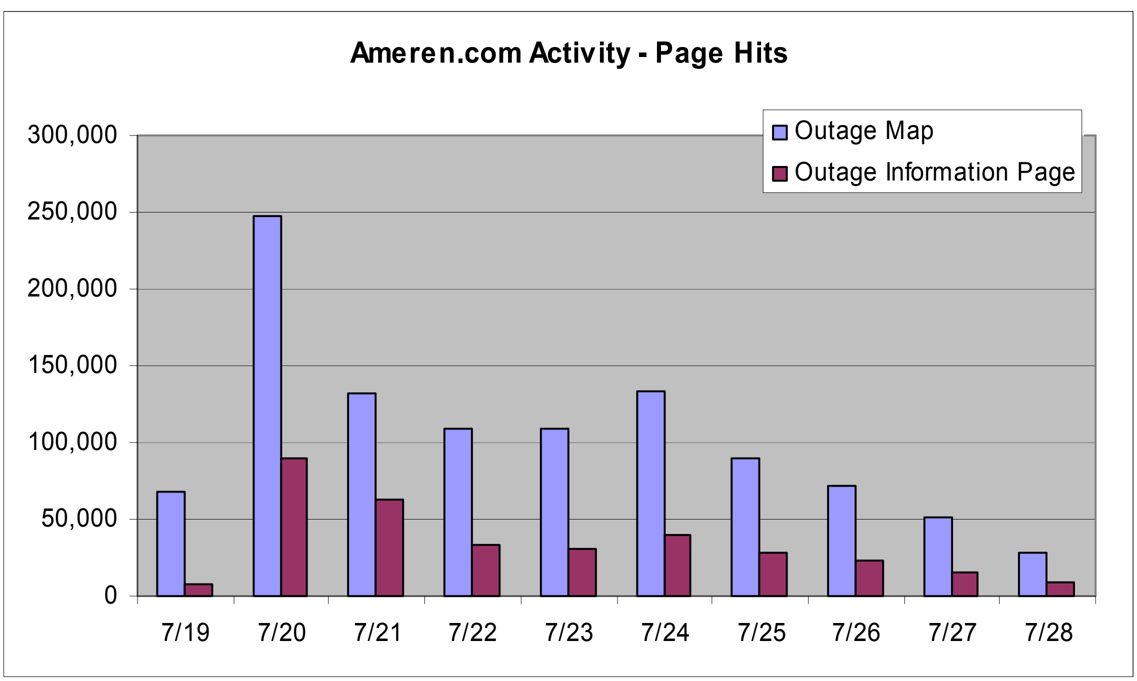
The third technical difficulty involved a T1 line going to First Contact that was operating at full capacity. Calls that came in over this capacity were met with silence. This issue has been resolved and in addition Ameren installed another T1 line to improve future performance.

While the Company did encounter several technical difficulties at the Call Center during this major outage, the Call Center personnel responded well and in an organized manner to an overwhelming volume of customer calls.

Website Usage

One of the ways that Ameren attempted to expand its efforts to communicate and provide information to the general public during major outages was through the use of its web site. The Outage Information Page website provides an update on restoration efforts, outage tips, and a way for individuals to view their outage status. Outage information is provided on a map organized by zip code to provide a method for the customer to locate their service location. Updates were posted to the website throughout the day. This resource was publicized by Ameren and through the news media. Customers utilized this website throughout the course of the outage restoration following these storms. However, the website's popularity caused an overload to occur the second day of the outage.

After the severe storms on August 13, 2005, customers also utilized the website to check on restoration progress. Over the period of August 13th to 20th, the highest day's usage was 28,400 hits on August 15th. Customers utilized the outage page, particularly the outage maps, in far greater numbers for information following the storms on July 19th and 21st.



Source: Ameren Presentation

On July 20th, network problems caused the outage maps and the "My Electric Outage" page to be unavailable from 8:00 AM to 4:30 PM. The ultimate cause of the problem was a network configuration issue that occurred due to the unexpected number of hits to the website during a period of time. This problem has been corrected and the infrastructure is now equipped to handle the level of traffic that occurred during the last storms. In addition, the Company has developed and will implement an enhanced infrastructure in January 2007 for its customer information applications, such as the outage maps. This will provide additional stability to these applications through load balancing and high redundancy.

This outage page proved to be very helpful to the customer and the Company should continue to explore ways to make it even more helpful and reliable. One item that could be promoted during this time is the customer's registration on the site in order to view more detailed information regarding their specific location. This registration requires an account number which is not always available during an outage.

Recommendation: AmerenUE should promote customer registration on its website to ensure that customers can access customer-specific information on service restoration in the event of a storm related outage.

Cooperative Efforts among City/County and Emergency Management Officials for Citizens Needing Special Assistance

Staff reports regarding AmerenUE's storm restoration efforts issued in 2002, 2004 and 2005 discussed the importance of communication and coordination between AmerenUE and city/county officials during a widespread outage. The Company has responded to specific recommendations made in these reports designed to educate emergency personnel and city and county officials regarding storm restoration procedures. In addition, communication efforts to be utilized during an outage were established. The Staff believes there has been significant progress in this area. This report does include several recommendations to achieve further improvements based upon the lessons learned in this major outage.

Customer comments during the public hearings in this case highlighted the need for specific efforts to take care of special customer populations, such as those customers with medical needs and the elderly. It should be noted that in this investigation, Staff came across numerous acts of heroism by people who were helping their neighbors. Several customers at these hearings communicated to Staff their belief that neighbors should take a more active role during an outage in assisting citizens that are elderly, alone or dealing with medical needs. The ideas expressed here are nearly identical to those that resulted in the establishment of the current Operation Weather Survival (OWS) network system in St. Louis. The concept of a neighborhood "watch group" was discussed with customers at several public hearings, after testimony was heard regarding concerns for the elderly and medical situations. These citizens could ensure that these customers are safe and, if needed, are transported to a location with power. Major widespread outages become emergency situations, especially in the weather conditions that existed on July 20th, and require the cooperation and participation of all interested citizens.

AmerenUE's efforts to restore power following a major storm should be a priority. Customers should not be involved in the discovery of technical and dangerous conditions. But given appropriate direction, customers can play an important role in the restoration process. This direction can come through a joint effort of AmerenUE and community agencies.

The Company can continue to work with city and county agencies to identify customers that may be at risk during an outage. These agencies could utilize this information to develop neighborhood groups that have responsibility for checking on these customers during an extended outage. The information that AmerenUE receives through its medical registry program could be a good way to start such a program.

Recommendation: City and county agencies, in conjunction with AmerenUE, should facilitate the development of neighborhood watch groups, or assess the ability of the current Operation Weather Survival (OWS) network system, to check on special needs customers during an extended outage.

Contact with City Officials & Agencies

Staff recommended, in its report following the ice storm of January 2002, that AmerenUE should contact city and county officials twice a year to update information regarding appropriate contact points. AmerenUE needs to maintain current information to easily contact these officials in the event that a particular area suffers a widespread outage. AmerenUE has implemented procedures to keep this information updated and programs to educate and communicate with the specific groups within their service territory identified below.

AmerenUE hosted several "Storm Schools" prior to this storm in an effort to educate the media, fire, police and city and county officials about what occurs during a widespread outage. AmerenUE believes that these were helpful in educating the personnel involved and will be repeated. AmerenUE has noted that attendance at these events could be better and is continuing to try to attract a larger audience. Staff believes the events of this summer may help with attendance at future Storm Schools.

Recommendation: AmerenUE should continue to make efforts to improve participation in the Storm Schools it offers for the media, fire, police, city and county officials.

AmerenUE has also attempted to expand its communication efforts with the general public by increasing its use of the media and an expansion of its web site information. AmerenUE faxed or e-mailed updates on the progress of restoration efforts to the major news media several times a day. These updates were also posted to the website. Customers with access to a computer were able to check on the progress of the service restoration effort through the Ameren.com website. The website provides information on a service map that allows the customer to view outage numbers and locations by zip code.

The power outages caused by these storms also impacted drinking water service in the area. For customers using private wells, loss of power often resulted in a loss of water from their well. For some of the customers being served by water utilities, drops in water pressure resulted in boil orders. Unfortunately, many customers who were under a boil order did not know they were under a boil order due to decreased access to their normal news sources. Many of these same customers also did not have access to power to boil water. During the public hearings in this case, Jackie Hutchinson of the Human Development Corporation testified that under similar circumstances in the future it may be appropriate to initiate communications through the OWS network system. In the Call Center Operations & General Consumer Communications section of this report Staff has noted a recommendation in this area.

In an effort to assess how effective the communications between AmerenUE and officials engaged in the restoration process were, Staff interviewed several city, county and state officials. Staff asked these officials if they believed AmerenUE communicated with them adequately or not and if they had any recommendations for future outage restoration efforts. Summaries of some of these interviews are provided below.

Captain Bob Young, St. Louis County Emergency Operations Center, was interviewed and noted his appreciation for AmerenUE's participation in the SEMA/EOC coordination meetings and their responsiveness to issues his office brought to their attention. Captain Young also noted appreciation of the AmerenUE storm center direct number. Captain Young made a special point to recognize the hard work and professional conduct of Dave Wakeman, who was one of the senior Ameren officials assigned to this restoration effort. Captain Young noted that they recognized that AmerenUE was overwhelmed but in his discussions with other emergency restoration groups he could not recall an expressed concern about AmerenUE's responsiveness.

Mayor Dudley, City of Potosi, was interviewed and also testified at the public hearing in Potosi. Mayor Dudley stated that for the first day to day and half of the outage contacts were good with the local district level AmerenUE engineers. After a day and a half though, calls were no longer being returned and AmerenUE was no longer responsive. At this point the only way to get action appeared to be through the SEMA/EOC coordination calls each morning and afternoon. The SEMO/EOC calls were helpful in getting AmerenUE pointed toward priority issues but Potosi still had some negative coordination experiences. At one point in the restoration effort, the City of Potosi was attempting to hook up a generator in order to return water service to the community and AmerenUE was required to be there to supervise the interconnection. Mayor Dudley believed he had appropriately coordinated AmerenUE's participation in this critical project, but when the hour for the restoration crews to rest came, Mayor Dudley believes they were told by senior AmerenUE management to go rest instead of supervising interconnection of the generator, which was close to complete. Also, Mayor Dudley believes that a local switch was the only remaining action to take for a group of customers to receive power and even though he made several attempts to bring this to AmerenUE's attention, it didn't appear that AmerenUE gave any priority to coming back and closing this switch.

Steve Moody, Operations Branch Chief, State Emergency Management Agency, was interviewed and noted his appreciation of AmerenUE's participation in the SEMA/EOC coordination meetings and being provided with the direct phone number for AmerenUE's storm center. Mr. Moody believed that AmerenUE was responsive to the requests identified in the SEMA/EOC meetings and demonstrated a high level of cooperation on several occasions, such as assisting with back-up generator interconnections, that were "above the call of duty." Like Captain Young, Mr. Moody also made a special point to recognize the hard work and professional conduct of Dave Wakeman.

Ken Walk, City of St. Louis Emergency Management Operations Center, was interviewed and shared several observations regarding AmerenUE's efforts to work with his organization during this restoration effort. Mr. Walk first noted his appreciation of the professional conduct and hard work of Mike Marx of AmerenUE who was in their office continually during the hours of operation. Mr. Walk noted that AmerenUE did everything they could do to help the City of St. Louis EOC and restore power as quickly as possible. Mr. Walk could not recall any instances of a lack of cooperation by AmerenUE or any instances where AmerenUE made unreasonable request of his organization during this restoration effort.

Jim Pasley, Area Coordinator for SEMA for Potosi and Washington County, State Emergency Management Agency, was interviewed and generally thought that AmerenUE did a good job keeping them informed of status and on what was being worked on. Mr. Pasley had several observations regarding the difficulty of AmerenUE's restoration effort in Washington County due to storm damage on feeders running through rough country that is heavily forested. Mr. Pasley was aware of helicopter surveys by AmerenUE to assess damage and to determine how to reach damaged areas. Mr. Pasley observed that one of AmerenUE's difficulties in this area was the difficulty getting to damaged infrastructure. In terms of web data, Mr. Pasley noted some difficulty with AmerenUE providing outage information by zip code and these zip code boundaries not being clearly understood by people trying to use this data. Like Mayor Dudley, Mr. Pasley also thought it would have been helpful to have had a local AmerenUE contact as opposed to having to go through the central AmerenUE office. Mr. Pasley observed one delay in restoration efforts that could be dealt with up front in the future related to AmerenUE tree crew ability to cut on damaged trees outside of their ROW. It appears that AmerenUE was at times unsure if they could cut on damaged trees outside of their ROW in order to gain access to their ROW for restoration work.

Recommendation: AmerenUE should further enhance its communications with field crews performing restoration work regarding AmerenUE's authority to cut trees outside of its right-of-way for the purpose of accessing its right-of-way for storm restoration work.

Recommendation: While centralization of AmerenUE's storm restoration process has brought about a number of coordination efficiencies, Staff believes that district managers should be available to local officials to deal with emergency situations and be provided with authority to request priority treatment of projects in their areas that require special attention.

Recommendation: AmerenUE's participation in the SEMA/EOC coordination phone calls during this restoration effort was extremely helpful to all the agencies involved. Staff recommends that SEMA request that each electric utility with damaged infrastructure attend and actively participate in all future storm restoration efforts where the level of damage prompts SEMA/EOC activation.

Recommendation: AmerenUE provided its storm center direct number to several city, county and state officials. Several officials reported that having this number available was extremely helpful to them. AmerenUE also reported that the calls received on this number did help it prioritize work on several critical projects. Unfortunately, AmerenUE also reported that too many individuals distributed this number to a broader group than it was intended to be provided to and at times issues that were not of a critical nature were being called in on this number, reducing the efficiency of personnel tracking outage repairs and dispatching crews. Staff recommends that AmerenUE continue to provide this number to key officials but caution these officials to be very careful in their distribution of this number, and that it be used only for emergency purposes.

Consumer Complaints

In many ways, this entire report relates to consumer complaints. Staff concerns and consumer complaints triggered the breakdown of categories and related assessments in almost all the sections of this report. What this section of the report provides is a brief summary of the consumer complaints received by the Commission and Staff associated with this major outage event.

During and following any major outage situation, a significant number of informal complaints and public comments are registered with the Commission via phone calls, letters, the PSC website, and the EFIS system.

The following table illustrates the number of complaints and public comments regarding the AmerenUE storm outage registered with the PSC from the date the storm began on July 19th through the end of August 2006.

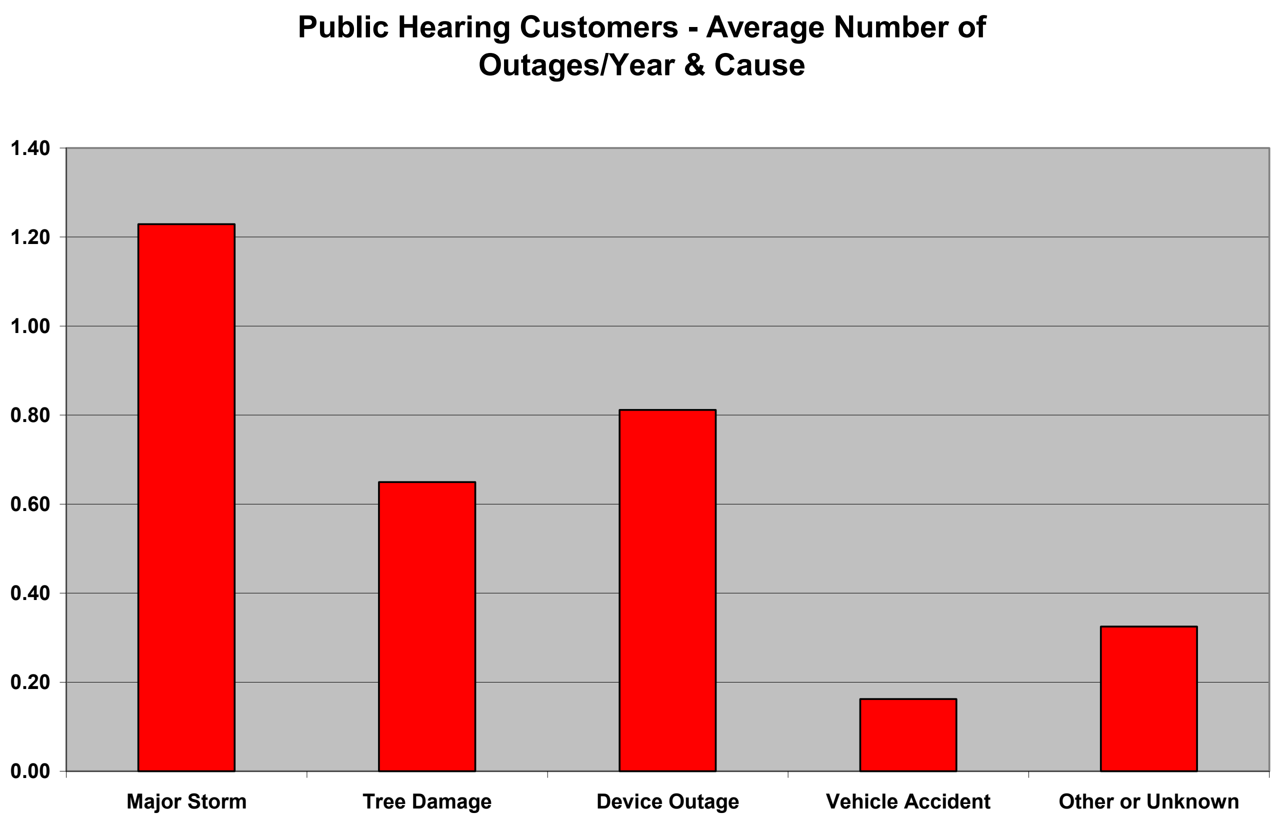
PSC Complaints & Public Comments Received

	Complaints	Public Comments
July 19-31	11	197
August 1-31	20	62

Questions from customers that did not require a response were classified as comments. If the inquiry from the customer involved a safety issue or frequent outages in their service location, these requests were classified as a complaint and routed to the PSC Engineering Department for further review. PSC Staff working on the outage reviewed every complaint and public comment filed with the Commission. In addition, PSC staff also attended every public hearing and met with consumers during these meetings to address their specific concerns.

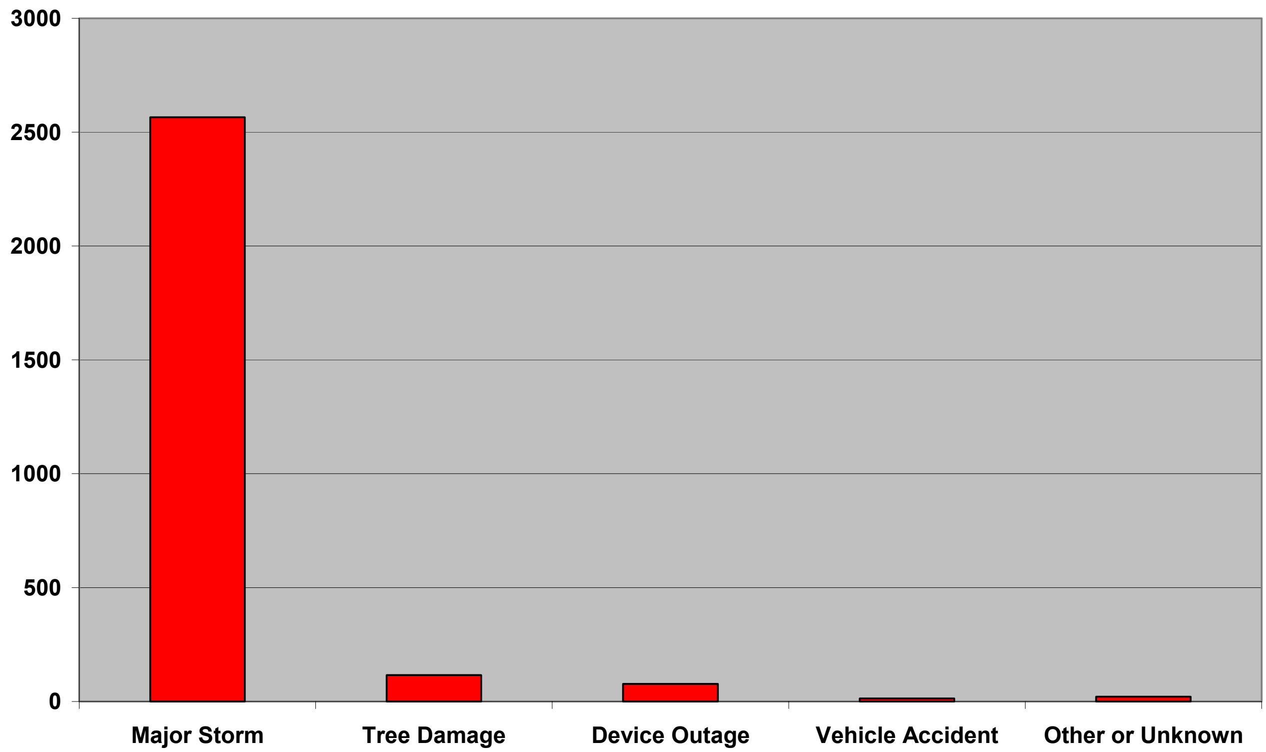
Customers during this storm outage noted the difficulties that they encountered when trying to get through to the Call Center. Many of the complaints cited the belief that the Company's lack of tree trimming in their area caused the outage to be more serious than it would have been otherwise. Many of the customers asked for more and better information regarding their outage and restoration status.

At the public hearings in this case, Staff visited with and took down information on nine witnesses particularly concerned about the frequency and duration of the outages they are experiencing. Staff reviewed the outage history for each of these customers and was able to determine a number of important trends from this data. The graph below illustrates the average number of outages per year experienced by these customers and what caused them. As this graph shows, major storms, non-storm related tree contacts and device outages were the major outage contributors for these customers. On average these customers have been experiencing 3.18 outages per year that lasted three minutes or longer.



While the above graph illustrates the number of outages, it does not provide any information on how long the outages were associated with each of these different causes. A review of the length of outage associated with each cause results in the graph below. As this graph shows, major storms resulted in the majority of outage durations being experienced by these customers. These customers have been averaging 46.5 hours without service per year and approximately ninety-two percent of these hours have been the result of major storm events.

Public Hearing Customers - Average No. of Minutes Without Service/Year & Cause



These observations provide additional foundation for the reliability and vegetation management recommendations in this report.

Compliance with Past Recommendations

The following section provides Staff's assessment of the actions AmerenUE took in response to the recommendations that the Staff made in its 2005 Storm Report. While the Company did take appropriate actions to respond to the Staff's recommendations made in that report, there are some instances where the Staff has developed additional recommendations in this report for that same area. The current recommendations, which are discussed in the Executive Summary and specific chapters of this report, may be the result of specific customer concerns brought to the Staff's attention or additional information discovered during this storm review.

'05 Recommendation # 1) The Company continues to maintain its mutual assistance agreements and in each major restoration effort evaluate the necessity of utilizing the agreements so that it will always have access to such resources when needed.

Status: Associated with this investigation, Staff carefully reviewed the agreements AmerenUE has in place for assistance from other utilities and their contractors following major outage events. The Mutual Assistance Agreements chapter of this report goes into detail regarding Staff's observations in this area. Staff believes that AmerenUE has acted appropriately in its continued participation and utilization of these mutual assistance agreements. It is important that AmerenUE continue to participate in these organizations and utilize them in an appropriate manner so that these resources will continue to be available to them when needed in the future.

'05 Recommendation # 2) The Company continues its plan to eliminate the tree trimming backlog by 2008. While AmerenUE should be commended for helping the utilities in the Gulf States restore electrical service, if it falls behind in its tree trimming schedule due to its efforts to help in the restoration in the Gulf States due to the hurricanes, AmerenUE should revise its schedule consistent with safe practices to return to its 4 year plan as quickly as possible.

Status: In Case No. EW-2004-0583 Staff continues to receive quarterly reports on AmerenUE's vegetation management (tree trimming) status. These reports are public but are not easy to understand for people who are not dealing with these numbers on a regular basis. Staff reviews the data submitted by AmerenUE pursuant to its obligations in this area and at this time believes that AmerenUE is in compliance with its obligations to address its tree trimming backlog on or before December 31, 2008. Staff has also been participating in field audits of AmerenUE's vegetation management program and believes that AmerenUE's program is in compliance with ANSI A300 standards. Staff does however note that a number of recommendations in this report focus on changes that should be made to AmerenUE's vegetation management program based on its observations in this review. These additional recommendations primarily relate to vegetation management program changes that may help to reduce the level of damage to AmerenUE's distribution system, and improve restoration efforts, following major storms in the future.

'05 Recommendation # 3) The Company should continue to review alternatives in the development of an estimate of restoration time provided to the customer.

Status: The development of an estimated restoration time (ERT) provided to the customer has consistently been an issue which Staff has examined in the analysis of past storm outages. Specific recommendations have been made by Staff to examine the development of the time to be provided to the customer. In its Staff Report on the 2005 Storm Outage, Staff also encouraged the Company to consider the scripts used to communicate with the customer. Many customer complaints received by the Commission noted that the estimates they received were so inaccurate, they would prefer to receive no estimate at all.

The 2005 Storm Outage Report noted the Company's efforts to work on the development of a better, more realistic provision of restoration time. Because of the importance of this type of information to the customer, the Staff recommended a further review of this estimate of restoration time.

Prior to the 2006 Storm, the Company took several steps to address the future utilization of ERT during major storm situations. The Company determined that it would disable the automatic generation and reporting of ERT to specific customers during major storms. They made the decision to produce a general ERT for all customers affected by this storm. This general statement of restoration was to indicate to the customer the severity of the storm and the potential for an extended outage.

After the storms on July 19th, AmerenUE issued information to the media and government officials that indicated that all customers would be restored within three to five days. On July 21st, the second wave of storms hit the service area and the estimates were updated to reflect the greater amount of damage brought on by these storms. As field checkers are able to determine the extent of damage and assign crews, more information is determined regarding the actual repairs needed and the relationship of this repair to others pending. As a crew is assigned to a job, they are required to enter an estimate of restoration time for that job.

Several messages have been developed and were used during this storm restoration effort to communicate the extent of the storm damage to customers. The following are examples of these messages:

> *Thank you for calling AmerenUE. Due to wide spread storm damage in the St. Louis metro area all efforts today are dedicated to power restoration. If you are calling for any reason other than to report an outage or emergency situation, please call back at a later date. We apologize for any inconvenience and thank you for your understanding.*
>
> *Due to wide spread storm damage in the St. Louis metro area, estimated restoration times are not available at this time; however, extended outages are anticipated and alternative arrangements for elderly or persons with medical needs are recommended. Downed wires may be energized and pose a serious hazard. Do not approach them. All non-outage related service requests have been suspended. If you are calling for any reason other than to report an outage or emergency situation, please call back at a later date. We apologize for any inconvenience and thank you for your understanding.*

The Staff believes that it was appropriate for AmerenUE to disable its ERT when it became clear that the storm had caused major, widespread damage throughout the Company's service area. Staff has reviewed all of the complaints and comments filed by customers as a result of this outage. The number of customers mentioning this issue has been significantly reduced from prior outages. While some customers still wanted an estimate of their restoration time, many more customers simply wanted better communication regarding the extent of the outage.

The Company has responded appropriately to the Staff's recommendation regarding estimated restoration time. The Call Center chapter of this report provides more detail on the utilization of estimated restoration time associated with the July 2006 outage.

'05 Recommendation # 4) The Company continues its efforts to communicate with its medical equipment registry customers the importance of customer initiated alternatives being available in the event of an extended outage.

Status: AmerenUE provides customers with a letter clearly explaining the provisions of the Medical Equipment Registry (MER). The letter is sent to all new enrollments, annual renewals and then again with the confirmation of new enrollments. This letter has been revised several times in response to Staff concerns noted in the prior Storm Reports of 2004 & 2005. The Company has rewritten its MER letter to customers to emphasize that it is very important that these customers have developed a back-up plan to be implemented in the event of a major widespread outage. The letter also includes information about a dedicated telephone number that MER customers can call in the event of a power outage at their residence.

The letter contains the following language:

> *We realize the importance of electric service to you. However, since we cannot guarantee uninterrupted electric service, you may want to refer to the supplier of the equipment or your physician for a back-up system. You should also be aware that after major storms or other unforeseen circumstances beyond our control, it may not be possible to restore service for lengthy periods of a time, and a back-up plan should be considered. While we will work as quickly as possible to restore service, priority treatment is not ensured.*

Customers in the MER program have taken advantage of the special phone lines to report their outage. The following table illustrates the large number of calls received in on this phone line to accept calls from MER customers and to report wires down.

WIRE DOWN AND MEDICAL EQUIPMENT REGISTRY
CALLS IN TO SPECIAL PHONE LINES

Date	Calls Offered	Calls Handled	% Answered	Average Speed of Answer (min:sec)
07/19/06	3067	975	31.79	6:58
07/20/06	13,629	12,903	94.67	0:27
07/21/06	11,732	11,460	97.68	0:10
07/22/06	8,344	8,301	99.48	0:03
07/23/06	7,065	7,026	99.45	0:03
07/24/06	6,753	6,695	99.14	0:06
07/25/06	4,926	4,910	99.68	0:04
07/26/06	4,064	4,049	99.63	0:03
07/27/06	2,538	2,531	99.72	0:03
07/28/06	1,593	1,562	98.05	0:14
Total	**63,711**	**60,412**	**94.82**	**0:17**

Source: Company response to Staff data request #7

It is difficult to directly compare the figures on medical equipment registry customers calling in from the prior storm in 2005 to this storm since this phone line also took reports of wires down. The figures above include both items. There were also some issues with the dedicated phone numbers being distributed to others outside of the specific group they were intended for. Even with these difficulties, it appears that the vast majority of the calls were answered in a timely manner.

The Staff believes that the Company's actions represent an appropriate response to this recommendation in the 2005 Storm Report.

’05 Recommendation # 5) Representatives from the nursing home industry and the Company meet to discuss the feasibility of AmerenUE’s proposal regarding the registration of long term care facilities.

Status: Representatives from Ameren’s management in Distribution Operations and Customer Relations met with representatives from the Department of Health and Senior Services (DHSS) on February 23, 2006, to discuss concerns regarding nursing home facilities during periods of extended outages. The group reviewed the Ameren proposal to register qualified facilities. Over the next several months, Ameren and DHSS continued their discussions to develop a list of nursing homes. From this list, Ameren determined which facilities were Ameren customers and then applied technology to plot the facilities on area maps.

During the most recent outage in July, Ameren worked closely with municipalities and other government offices to identify a number of facilities requiring special attention. The Company is continuing to investigate alternatives to help meet the need for the safety and health of this group.

The Staff believes the Company has responded appropriately to this recommendation in the 2005 Storm Report.

’05 Recommendation # 6) The Company should expand its presentation of informational meetings regarding major outages prior to storm season to include city and county officials.

Status: Ameren held a number of meetings with community leaders, mayors and municipal officials in response to this recommendation. The Company hosted the St. Louis County Municipal League monthly meeting at its corporate headquarters on January 26, 2006. Information was presented at the meeting about storm preparation and response. Approximately fifty community leaders attended the meeting. Ameren had a number of staff available to respond to questions and conducted tours of its EOC. A similar meeting was also held with the St. Charles County mayors and city administrators.

Two public meetings were held for the community at large at the Olivette Community Center on November 29 and December 1, 2005. A number of Company personnel were available to answer questions about storm restoration, tree trimming, and power quality. Customer service personnel were also available to answer specific questions related to a customer's account.

The Staff believes the Company has responded appropriately to this recommendation in the 2005 Storm Report. One of Staff's recommendations in this report is that AmerenUE continue to hold these informational meetings and make efforts to increase the number of attendees at these meetings.

'05 Recommendation # 7) The Company should develop an efficient method of communicating the status of restoration efforts with city and county officials in the affected area during a major outage.

Status: Community leaders were given an opportunity to receive storm restoration updates and information directly from Ameren via an e-mail. The community leaders were told that if they sent a request to an Ameren provided e-mail address, they would automatically receive updates during a storm. Staff was added to this e-mail distribution list and during this restoration effort, Staff received regular updates through this e-mail server list.

The Staff believes the Company has responded appropriately to this recommendation in the 2005 Storm Report.

Other Utility Impacts

Following the storms on July 19th and 21st, Staff received a number of phone calls and e-mails noting problems with water and telecommunications service. Water and Sewer Department and Telecommunications Department Staff have been in contact with the utilities they work with in the areas impacted by these storms and prepared the following assessments. As can be seen from the following, loosing power, and having limited back-up power, has impacts much broader than just loosing electric service.

Impact of the Storms on Telecommunications Services

Data requests were sent to telecommunications companies providing basic local telecommunications services in St. Louis, St. Charles, Jefferson, Washington, Iron, Franklin and St. Francois counties. These companies were selected based on lines served within any exchanges located within these seven counties according to the company's most recent annual report. Responses were received from eighteen companies. Staff did not pursue responses from the non-responding companies because these companies rely on facilities provided by an underlying carrier who provided both wholesale and retail information. Several companies reported the storms did impact their service offerings; however, only to the extent the underlying carrier experienced a problem or the telecommunications equipment supplied by the customer was dependant on commercial power. In this respect, four telecommunications companies (AT&T Missouri, CenturyTel, Charter and NuVox) had facilities that were directly affected by the storms of July 19th and 21st.

Listed below is a summary of how these storms impacted these four companies:

	Totals
1. Central offices impacted by the storm	34
2. Remote terminals impacted by the storm	178
3. Total access lines in the 7 counties	1,067,355
4. Total access lines in exchanges exposed to power & storm damage	954,343
5. Lines out-of-service due to loss of power	37,599
6. Lines out-of-service due to damaged plant	9,785
7. Total lines out-of-service (Line 5 + Line 6)	**47,384**
8. % of lines in total area without service (Line 7/Line 3)	**4.44%**
9. Total lines maintained by generators or battery back-up	906,959

Telecommunications Service Outages

A total of 47,384 lines experienced telecommunications service outages due to these storms. The reasons for customers experiencing service outages are two-fold. One reason is due to physical damage to telecommunications company facilities such as downed or damaged lines. Physical damage to telecommunications company facilities was the cause for telecommunications service outages for 9,785 St. Louis area lines. A second reason is due to the loss of commercial electrical power since all telephone service is somewhat dependant on electrical power. Analog telephone service requires electrical power only at the central office; however, other telephone technologies may require power at multiple locations. For example, telephone service provided by digital line carrier (DLC) requires power at both the central office and the DLC or node. In cable and fiber to the home applications electrical power is required at potentially three locations: the central office, a DLC or node and at the customer premise, including power for the customer's telecommunications equipment. Loss of commercial electrical power caused telecommunications service interruptions or outages for 37,599 consumers.

Proactive measures were taken by certain companies to try and minimize the number of customers experiencing an outage. For instance, back-up batteries and/or generators were placed at central offices or head-ends and remote terminals. Back-up power provided by telecommunications companies maintained telecommunications services for

906,959 lines. Absent the use of batteries and generators all of these lines would have experienced a telecommunications service outage. The average amount of time a company used back-up power was thirty-two hours. Some companies attempted to accelerate restoring service by using either contract labor or additional resources from other locations within their respective companies.

911 Service

Action was taken to ensure 911 services were available and working in all areas. Companies re-routed traffic for eleven public service answering points (PSAPs) which are locations where 911 calls are answered. Re-routing calls to a particular PSAP is necessary if calls to a PSAP location cannot be completed. In this instance the eleven PSAPs lost electrical power. The 911 networks are continually monitored and if a PSAP experiences problems a re-route of the 911 traffic to another PSAP will occur. The eleven PSAPs that lost power serve approximately 240,000 lines and 911 traffic rerouting was transparent to callers. The first occurrence of rerouting 911 traffic occurred at 7:45 PM on July 19th and the 911 network was finally back to normal by 9 AM on July 24th.

The Storms Did Create Call Congestion

The storms did create significant call congestion. Many callers received a "no circuits available" announcement or experienced a delay in receiving a dial tone. Callers attempting to dial three specific numbers in the St. Louis area created call congestion problems. Two of these telephone numbers are associated with AmerenUE's call center (314-342-1000 & 314-342-1111) while the third number serves a weather forecast hotline (314-321-2222). Implementation of network traffic controls occurred on these three numbers on three different occasions during the July 19th, 20th and 21st time period for a total of 19.5 hours. Network traffic controls limit the number of calls that can be completed to the terminating numbers and ensures network resources are available to complete other calls without completely shutting down the network.

Recommendation

Commission rule 4 CSR 240-32.060 (5) includes requirements for telecommunications companies in the event of an emergency such as an electrical power outage. Currently telecommunications companies are required to make reasonable provisions to meet emergencies resulting from lightning or power service failures and unusual and prolonged increases in traffic. The primary specific requirement is for a company to have a minimum of three hours of battery reserve at each central office. Although Staff has not currently evaluated the costs, the Commission may want to give consideration to expanding its rules to include a requirement that battery reserves and/or generators be installed or made available for Digital Line Carrier and node locations as well as the customer's location. Such a proposal, if implemented, could help to minimize service outages in the future for providers whose service requires electrical power.

Recommendation: (Telecommunications) The Commission may want to give consideration to expanding its current back-up power requirement to include battery reserves and/or generators for Digital Line Carrier and node locations as well as the customer's location.

Impact of the Storms on Water Utilities

As a result of the facility-specific impacts shown in the table at the end of this section, Missouri American Water Company's (MAWC) production, system pumping and usable storage capacities were significantly reduced, particularly in its systems located north of I-70. Also, MAWC's ability to pump in "replacement" water from unaffected supply and storage facilities was affected. As a result of these various capacity reductions, system pressures in certain communities located north of I-70 dropped below 20 psi. Due to this drop in pressure, MAWC issued a precautionary boil water advisory for the entirety of its system located north of I-70. MAWC did not, however, have any customer service outages.

The boil water advisory was issued on July 19th at 11:25 PM, and was subsequently lifted on July 21st at 4:30 AM. The boil water advisory was lifted after water samples taken from the affected areas on July 20th at approximately 9 AM were tested and found not to be contaminated. Follow-up water sampling was also done at approximately noon and 3 PM on July 20th, with the results from those sample tests also showing no contamination.

In addition to MAWC's efforts to ensure that its facilities were returned to service as quickly as possible, MAWC also made arrangements with a local supplier to have bottled water available for distribution in the affected area if it became clear that there was a demand for the bottled water. However, the Company did not have to implement the plan for making the bottled water available due to a lack of requests for it. MAWC was also advised by the Staff, during the evening of July 20th, to contact the EOC at SEMA regarding the arrangements it had made for a bottled water supply, as it was believed that SEMA was the best point of contact regarding the possible need for distribution of the bottled water supply that was available.

MAWC's North County production facility has been in operation since 1954 utilizing dual power feeds from separate supply grids, and until this storm had experienced only one other situation where both of these power feeds were lost at the same time for a period of over one hour.

Recommendation: (Water) MAWC should assess additional methods to get information to customers regarding boil orders, if any, during major outage events when customers do not have access to the normal media they use to receive information. These additional means may include the OWS network system, the Post Office, flyers posted at shopping centers, super markets, gas stations, and other locations where people are likely to read a notice.

Recommendation: (Water) MAWC should assess whether it needs to have on-site back-up generators installed, or have access to portable generators, at its major production facilities in order to provide reliable water service in the future given the outage history they have experienced at these facilities.

Notes Regarding Table Below on Impact of Storms on MAWC Facilities

All of the electric service interruptions reported in the table below occurred shortly after the storms on July 19th. While the primary and secondary power feeds to all of the affected facilities are provided by AmerenUE, the secondary feeds to each of the facilities are provided from different service "grids" than the grids from which the primary feeds are provided. Power supply was restored to the affected facilities at various times after the initial outages, and initially only to one of the power feeds for each of the facilities. The most important restoration of service shortly after the storms on July 19th was the restoration of service to the North Plant production facility at approximately 4:30 AM on July 20th.

Affected Facilities	Impact of Storm on Facilities
Fee Fee Storage Facility	Both the primary and secondary power feeds were lost.
Ferguson Storage Facility	Both the primary and secondary power feeds were lost.
Lucas & Hunt Booster Station	Both the primary and secondary power feeds were lost.
Meramec Production Facility	Both the primary and secondary power feeds to the plant's intakes were lost.
North Plant Production Facility	Both the primary and secondary power feeds were lost, and an on-site back-up generator was also damaged and could not be used for a short period of time.
Rock Hill Booster Station	Both the primary and secondary power feeds were lost.
South Plant Production Facility	Both the primary and secondary power feeds to the plant intakes were lost.

Other PSC-Regulated Water & Sewer Utilities

Other utilities contacted by the Water & Sewer Department regarding the possible impact of the storm were: Central Jefferson County Utilities; KMB Utility Corporation; Mill Creek Sewers; Port Perry Service Company; and Terre Du Lac Utilities Corporation. None of these utilities reported service-related problems, but Central Jefferson County Utilities and Mill Creek Sewers did report that there were short power supply outages in and around their service territories.

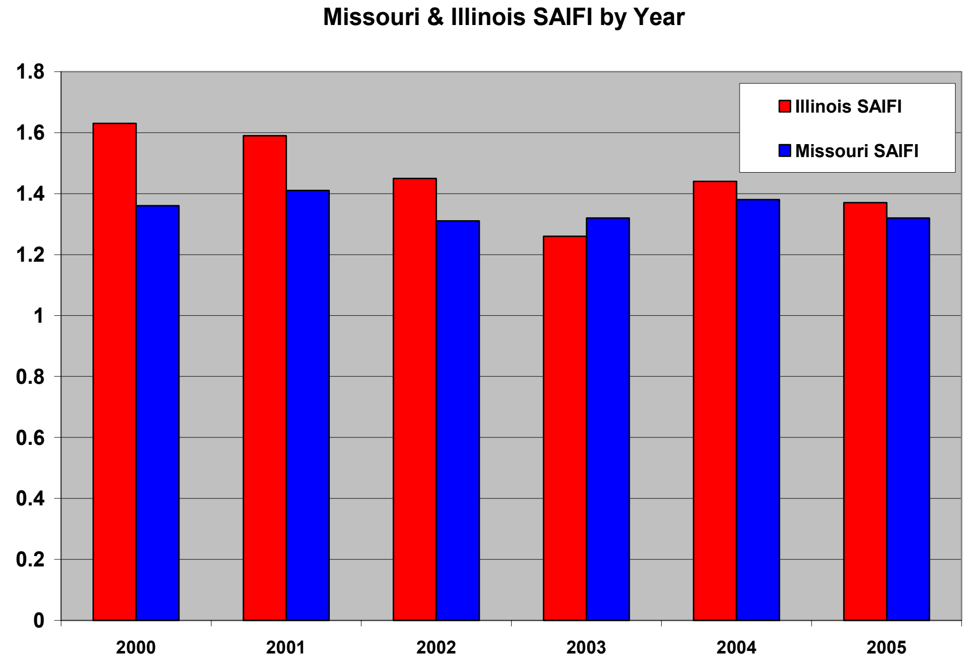
Appendix A
Electric Utility Reliability

Associated with this investigation, Staff reviewed AmerenUE's procedures to address day-to-day service reliability in general. Staff notes that general reliability of service and improved storm restoration performance through preparation for major storm outage events are two different topics with very limited relation to one another. Tree trimming to reduce the frequency of tree limb related momentary outages is very different than trimming to reduce the frequency of large limb damage to electric utility infrastructure during major storms.

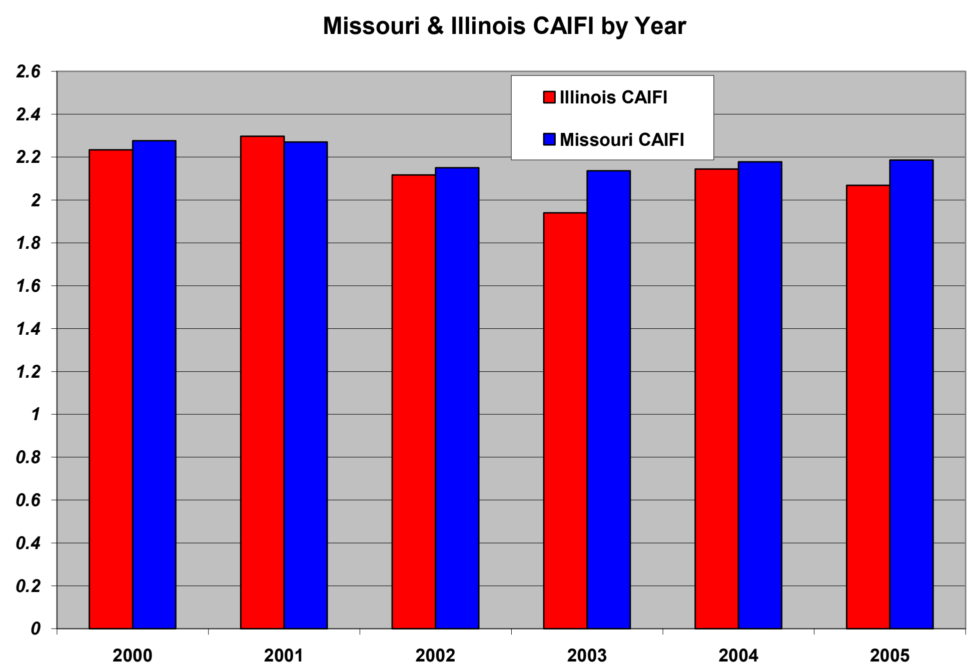
Staff's review of service reliability standards in nearby states shows that some states have implemented reliability reporting requirements while others have not. Ameren operates in both Missouri and Illinois. Ameren has stated in interviews with Staff that its procedures for tracking and improving reliability are basically the same in both states even though the reporting requirements are different. In Illinois service reliability metrics are required to be reported on a regular basis while in Missouri reporting is on an as-needed basis.

Associated with this investigation, Staff reviewed a number of standard reliability indices for Ameren's facilities in Missouri and Illinois and developed the following graphs to illustrate the results of this review.

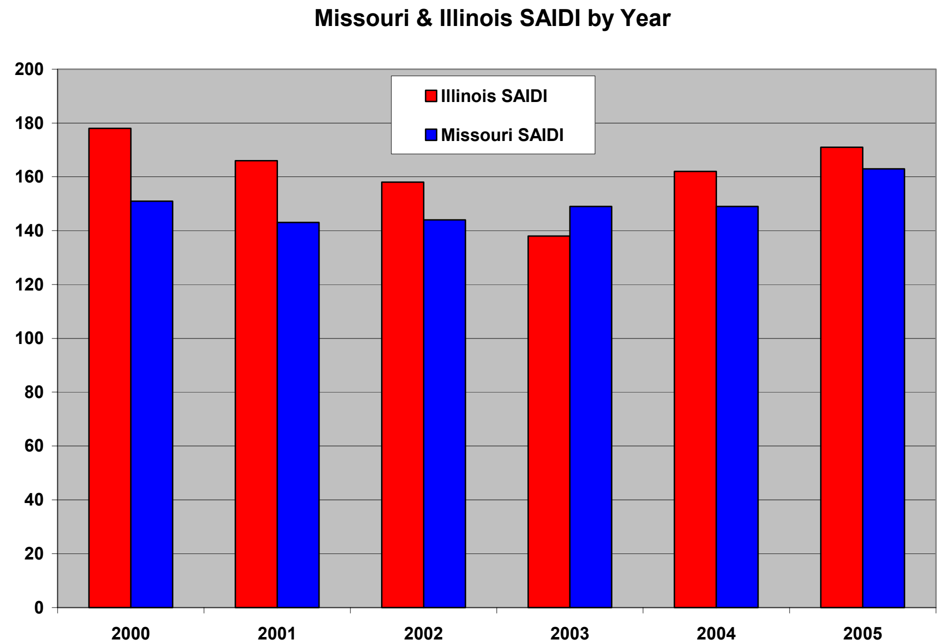
The following graph illustrates SAIFI which is calculated as the total number of customer interruptions in a year divided by the total number of customers served.



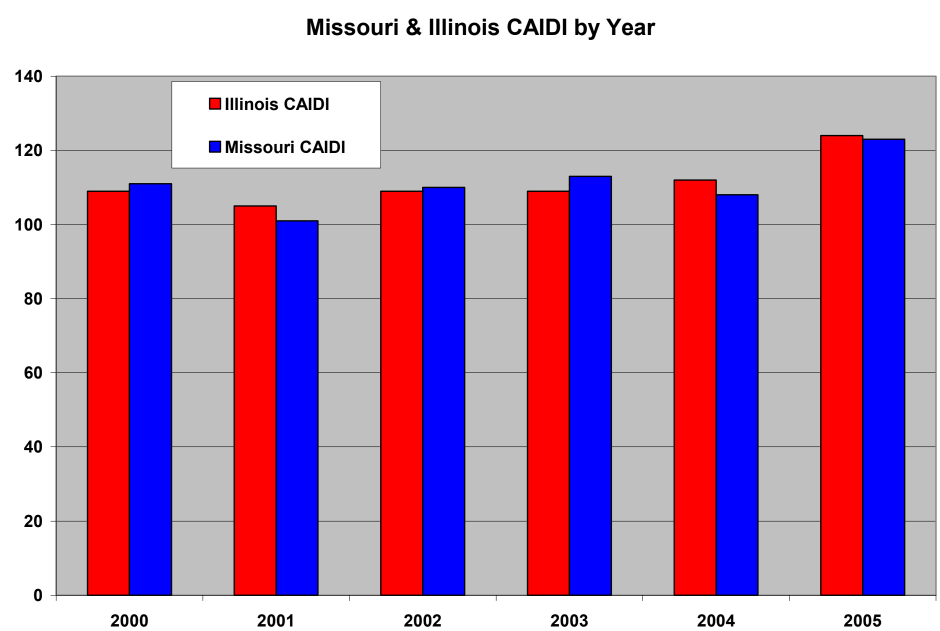
The graph below illustrates CAIFI which is calculated as the total number of customer interruptions in a year divided by the total number of customers affected by an interruption.



The graph below illustrates SAIDI which is calculated as the sum of customer interruption durations (in minutes) in a year divided by the total number of customers affected by an interruption.



Finally, the graph below illustrates CAIDI which is calculated as the sum of customer interruption durations (in minutes) in a year divided by the total number of customer interruptions.



AmerenUE has several programs in place focused on tracking and improving reliability within its different districts (usually referred to as divisions). These programs include the following: Overhead Circuit Inspections, Tap Fusing, Recloser/Sectionalization, Division Reliability Reviews and Weekly Device Outage Reviews. In addition to these formalized programs, AmerenUE also responds to individual customer requests related to frequent momentary outages and customer-specific concerns about general reliability.

AmerenUE's Overhead Circuit Inspection Program utilizes its vegetation management contractors to assist in identifying infrastructure problems. Vegetation contractors are trained to identify possible equipment problems and notify AmerenUE of these issues through overhead equipment damage reports. This program was implemented in 2002 and, along with AmerenUE's Third-Party Attachment Audit Program, is the primary means that AmerenUE is using to assess the condition of its non-feeder distribution poles.

AmerenUE's Tap Fusing, Recloser and Sectionalization Program utilizes past outage information, normalized to remove storm events, and the numbers of customers on each circuit to determine optimal locations to install tap fuses, reclosers and/or additional circuit sectionalization. Tap fuses limit the extent of an outage to other customers due to issues that may only affect a single service tap. Automatic reclosers detect fault conditions and rather than simply tripping the circuit as a fuse would do, will attempt several times to close the circuit back in and will only trip out of service if the fault appears to be more than a momentary condition. Sectionalization is similar to looping in that customers may be served from more than one circuit and switches can be set to automatically connect to a different circuit if loss of power is experienced on one side of the switch. The types of faults where this equipment is useful in improving reliability may include a single tree branch contacting a line or a squirrel on top of a pole mounted transformer. Division engineers review the information from tap fuse studies to coordinate these potential projects to improve reliability with other potential projects that may include reclosers and/or additional circuit sectionalization. Generally, installation of this type of equipment is more easily justified as the number of customers on a particular circuit increases.

The tap fusing program was implemented in 2003 and has resulted in approximately 1,200 tap fuses being installed. AmerenUE currently has approximately 2,400 reclosers and sectionalization devices on 1,143 12kV circuits.

AmerenUE's Division Reliability Reviews bring together division construction, forestry, operating, substations and reliability engineering on a semiannual basis to review worst performing circuits, extended outage data, frequent interruptions data, longest outage data, highest customer interruptions data and data describing the primary causes of outages. Each division's engineering group then annually generates a reliability improvement plan. These plans include recommended upgrades to improve worst performing circuits, reduce high loads on particular feeders, tap fuse installations, animal guarding and other projects. Each of AmerenUE's divisions is given a SAIFI target to hit and a timeframe to meet this target. SAIFI stands for System Average Interruption Frequency Index and is calculated based on the total number of customer interruptions in a year divided by the total number of customers served. As previously shown, from year 2000 to 2005, AmerenUE's Missouri SAIFI has varied between 1.31 and 1.41.

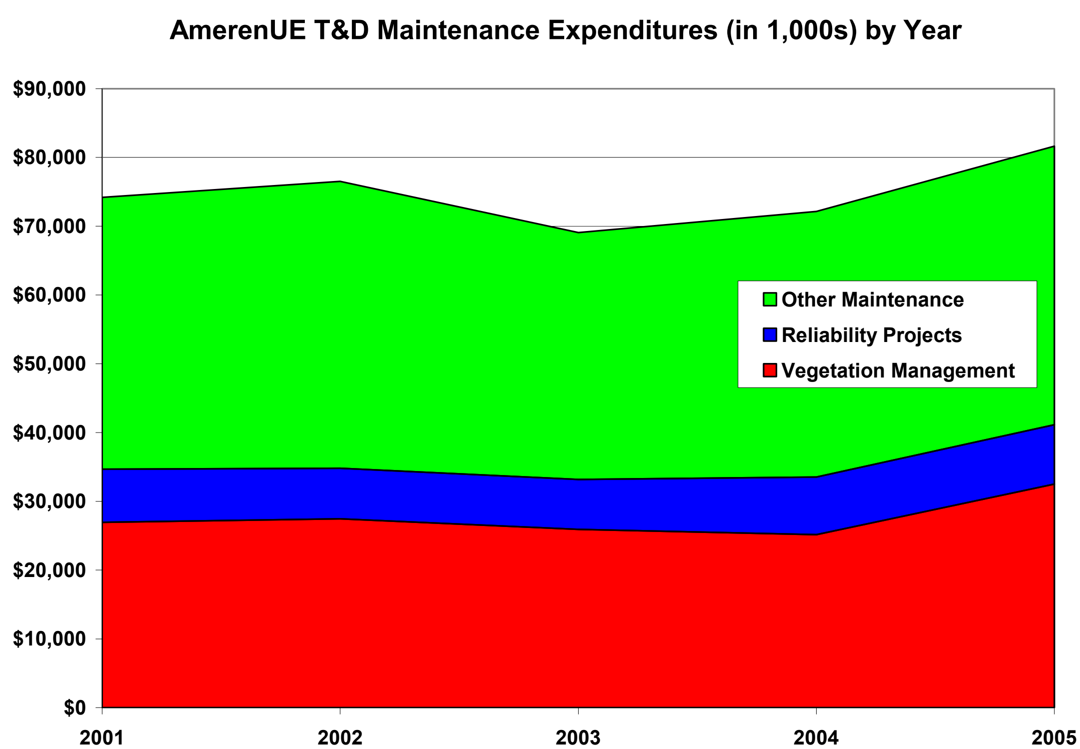
Raw outage data, including data from major storms, is typically normalized per The Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 1366 to remove major storm outages before reliability indices, including SAIFI, are calculated. Without this normalization it is possible that improvement work to address a particular reliability metric could be attempting to fix a problem that doesn't exist without the extraordinary impacts of a storm that is unlikely to happen again in the near future.

Each week Device Outage reports are provided to each division's engineer. Devices that experienced an interruption in the past week and having three or more interruptions in the last year are highlighted. Each division engineer then decides what action may be necessary, if any, for these devices and if a repair action is required it is scheduled in AmerenUE's Outage Analysis System (OAS).

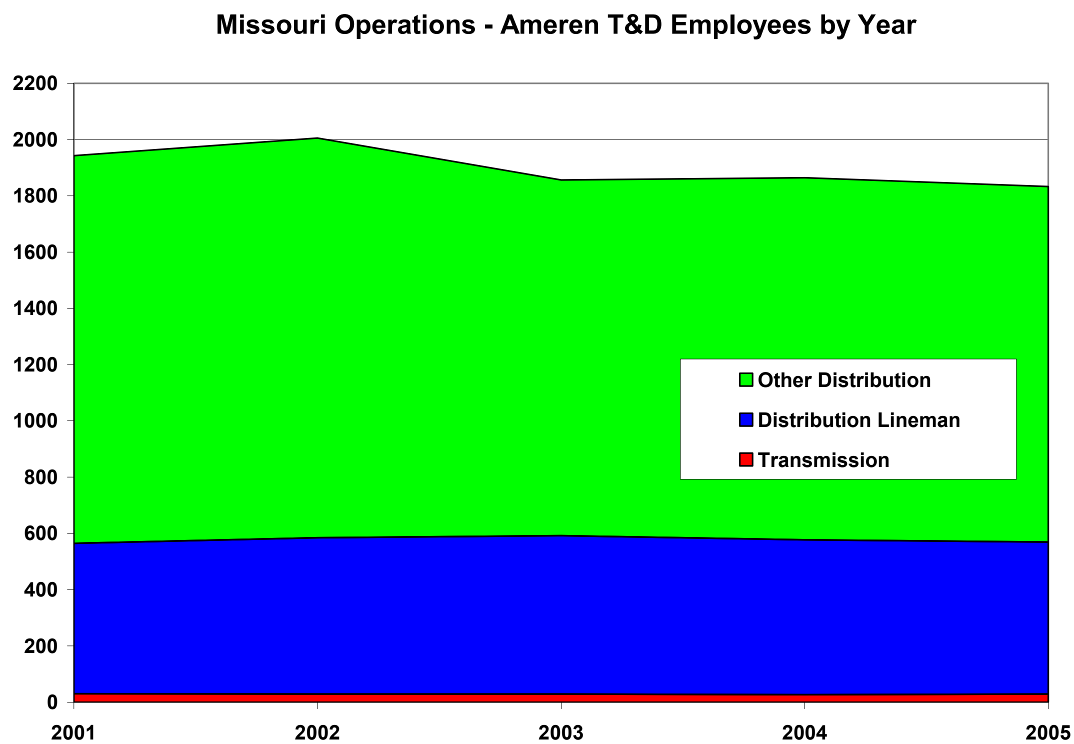
When particular reliability concerns are noted, AmerenUE assigns personnel to patrol and inspect these circuits. These concerns may be brought to AmerenUE's attention through customer calls, calls from local or state elected officials or calls from the Staff.

Projects identified in the programs above that require financial review, over $50k, are annually submitted to the Capital Review Committee within Ameren for prioritization. These programs are then assessed using AmerenUE's Integrated Spending Prioritization Tool that scores potential projects on their perceived impacts on safety, reliability, customer satisfaction, operations, cost and strategic objectives. The total expenditure levels made available to these programs each year are determined by AmerenUE based on overall spending targets and then operations and maintenance expense and capital expenditure spending targets are developed based on analyses of anticipated cash flow, net income, credit ratings and strategic goals.

In an effort to identify trends in transmission and distribution (T&D) maintenance funding by Ameren, Staff requested data from AmerenUE for 2001 through 2005. Expenditure levels for this time frame are shown in the following graph.



AmerenUE T&D operations employee levels by function are shown in the following graph (not including contractors). AmerenUE has stated in interviews with Staff that the "other distribution" employee reduction between 2002 and 2003 was a result of management and clerical staffing reductions. Transmission and distribution lineman levels remained relatively unchanged between 2001 and 2005.



One issue that Staff has noted in the past that certainly contributes to reliability problems on AmerenUE's system is its high percentage of circuits that are routed in the backs of housing lots versus along streets. This is sometimes referred to as "backlot routing". AmerenUE estimates that 40% of its distribution facilities in Missouri are located in off-road locations. In the St. Louis City/County area, AmerenUE estimates that the number of off-road distribution facilities may be as high as 50%.

Backlot line placement greatly increases the exposure of power lines to damage from trees and compounds storm restoration efforts due to difficulty accessing these corridors after a major storm. When a utility pole breaks in these backlot routed areas, the effort to bring a utility pole and drilling rig into these areas without damaging fences, hedge rows, rock gardens and landscaping can be extraordinary.

Associated with this case, six public hearings were held in the areas most impacted by storm related outages. It was anticipated that many of the witnesses would have concerns about vegetation management and how long they were without power associated with this restoration effort. In addition to these concerns many of the witnesses expressed frustration with the duration and frequency of outages they are experiencing not related to storms. The Consumer Complaints section of this report includes an outage analysis section on nine customers that expressed reliability concerns during the public hearings.

AmerenUE has, within the last five years, implemented a number of initiatives to improve reliability of service to their customers. Associated with their current rate case, Staff and AmerenUE are discussing additional programs to reduce storm related damage exposure to the portions of AmerenUE's system that serve large numbers of customers (feeders / backbone systems). In order to assess how successful AmerenUE's current and planned reliability improvement programs are, and provide the Staff with information on a more frequent basis for oversight purposes, implementing a reliability reporting rule is appropriate at this time. A draft rule that would accomplish this is attached in Appendix F.

Recommendation: Adopt and implement a Commission rule that requires electric utilities to annually report certain standard reliability metrics, their programs for attaining or improving these metrics, the status of these programs, and program funding levels.

Attached to the end of this appendix is a document from Cooper Power Systems (Reference Data R280-90-7) that provides a brief overview of reliability indices and how they can be improved by installation of different types of equipment.

Analysis of Distribution System Reliability and Outage Rates

R280-90-7

Reliability Analysis

Reference Data R280-90-7 provides information on the measurement and improvement of distribution system reliability. Standard indices to measure system reliability, outage rate goals, types of faults, and types of outages will be discussed. Both transient and permanent outages are included in the measurement of reliability. Examples of various types of distribution systems will show how outage rates can be reduced and system reliability improved by the application of distribution switchgear. Improvement that can be obtained through system automation using remote identification and remote switching will be included.

Performance Indices

When discussing outage rates, industry standard reliability indices will be used. Standard indices permit meaningful comparisons between utilities or between different divisions of a given utility. Most important, they allow evaluation of system changes by a direct comparison of past and future performance of a feeder or system as changes are made. An outage definition will vary from utility to utility. The standard indices used are listed below.

System Average Interruption Frequency Index (SAIFI)

Defines the average number of times that a customer's service is interrupted during a year. A customer interruption is defined as one interruption to one customer.

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

System Average Interruption Duration Index (SAIDI)

Defines the average interruption duration per customer served per year.

$$\text{SAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customers affected}}$$

Customer Average Interruption Frequency Index

Defines the average number of interruptions per customer interrupted per year.

$$\text{CAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers affected}}$$

Customer Average Interruption Duration Index (CAIDI)

Defines the average interruption duration for those customers interrupted during a year.

$$\text{CAIDI} = \frac{\text{sum of customer interruption durations}}{\text{total number of customer interruptions}}$$

Momentary Average Interruption Frequency Index (MAIFI)

Defines the average number of times that a customer's service is momentarily interrupted during a year. A customer interruption is defined as one interruption to one customer.

$$\text{MAIFI} = \frac{\text{total number of customer momentary interruptions}}{\text{total number of customers served}}$$

Momentary Average Interruption Frequency Events Index ($MAIFI_E$)

Defines the average number of times that a customer's service experiences a momentary interruption event during a year. An event is one, two, or more momentary interruptions during the short time period required by a device to restore service.

$$\text{MAIFI}_E = \frac{\text{total number of customer momentary interruption events}}{\text{total number of customers served}}$$

Average Service Availability Index (ASAI)

Defines the ratio of the total number of customer hours that service was available during the year to the total customer hours demanded. (Customer hours demanded = 24 hours/day x 365 days = 8760 hours)

$$\text{ASAI} = \frac{8760 - \text{SAIDI}}{8760}$$

For example, a SAIDI of 1.0 hours per year would be figured as follows:

$$\text{ASAI} = \frac{8760 - 1.0}{8760} = 99.989\%$$

Outage Rate Goals

An outage definition will vary from utility to utility. Some utilities define an outage as an interruption of electric service for a period of two minutes while others may consider five minutes of interrupted service an outage. There are two types of outages covered in the analysis. A sustained outage is defined as a loss of service for more than a normal reclosing interval. A momentary outage is a brief service interruption of less than a reclosing interval. Historically, power distribution systems have been designed to reduce sustained outages. Today, because of the increasing use of electronics and computer equipment, customers are more sensitive to momentary interruptions experienced during the clearing of temporary faults. Reducing both sustained and momentary outages is now a goal in designing system reliability.

Urban and Rural Systems

Outage rate goals will vary depending upon the nature of the distribution system. Urban systems typically have less line exposure than do rural systems. As a result, urban systems generally experience fewer outages per year than rural systems. Typical outage rate goals for urban and rural distribution systems are to limit outages to an average of 1.0 (urban) and 1.5 (rural) outages per year (SAIFI). With each outage lasting an average duration of 1 hour, (CAIDI), the average annual interruption is 1.0 hours for urban systems and 1.5 hours for rural distribution systems.

TABLE 1
Typical Utility Outage Rate Goals

Index	System Type	Operating Goal
SAIFI	Urban	1.0 Outages Per Year
SAIFI	Rural	1.5 Outage Per Year
CAIDI	Rural/Urban	1.0 Hours Per Outage
SAIDI	Urban	1.0 Outage Hours Per Year
SAIDI	Rural	1.5 Outage Hours Per Year
ASAI	Urban	99.989% Annual Service Availability
ASAI	Rural	99.983% Annual Service Availability
$MAIFI_E$	Rural	4.0 Interruptions per year

Feeder Length and Voltage

Many utilities have found that their service reliability deteriorated significantly when they converted to a higher distribution voltage (for example; from 4 kV to 13 kV). The higher distribution voltage allowed them to service longer feeder lengths and more customers with a given feeder; however, each outage that occurred affected more customers. The longer feeders also require more patrol time to locate and repair a fault.

To restore service reliability, the first step is to sectionalize each feeder into smaller sections. This limits the number of customers affected by a given outage and reduces the patrol time needed to locate and repair the fault. Operating experience of a number of utilities that have adopted this sectionalizing practice suggests that an optimum feeder segment is 3 to 5 MVA. As the load of a line segment approaches 8 to 10 MVA, outage rates increase to unsatisfactory levels.

When further reliability improvement is desired, some utilities have utilized loop operation of adjacent feeders, as shown in Figure 9. This operation not only sectionalizes the feeder into smaller segments, it allows the utility to restore service to customers at the end of a feeder, minimizing any outage to the smallest possible segment of the feeder. As an example, two large eastern utilities that have adopted this scheme have achieved the following service continuity records:

Utility A

0.715 outages per customer per year (SAIFI), 1.056 hours per outage (CAIDI), resulting in 0.767 outage hours per customer per year (SAIDI).

Utility B

0.475 outages per customer per year (SAIFI), 1.4 hours per outage (CAIDI), resulting in 0.665 hours per outage per customer per year.

Types of Faults

Maximum service reliability is achieved when the distribution system is designed and operated to minimize the effect of any fault that may occur. Two types of faults are encountered on an overhead distribution system: transient and permanent.

Transient Faults

A transient fault is one that does not require corrective action to remove the fault from the system. If the arc can be cleared quickly, before burning into a permanent fault, the cause of the fault is gone. Since no equipment damage has occurred, the circuit can be re-energized immediately and service returned to the entire system. A transient fault would result from occurrences such as lightning, an arc caused by an animal or tree branch that then falls clear, or the wind momentarily blowing two conductors together.

On most distribution systems, the majority of faults (60% to 90%) are transient in nature. With proper protection devices (fast tripping with fast reclosing), these faults can be cleared without a sustained outage.

Permanent Faults

A permanent fault is one in which permanent damage has resulted from the cause of the fault. A permanent fault usually requires some form of repair before power can be restored. Examples include a broken insulator, a broken conductor, or an automobile knocking a pole down. It also includes faults that are initially transient in nature but result in permanent damage to the system With permanent faults, the line must be de-energized, a line crew brought to the site, and repairs made. Outage times range from 30 minutes to many hours and produce sustained outages.

Outage Rate Reduction Methods

For faults on the main feeder line, a line-sectionalizing device (recloser or sectionalizer) can be used to divide the feeder into smaller line segments. All taps should have a protective device (fuses for small taps, a recloser or sectionalizer for larger taps) where they connect to the main feeder. Even on very small taps, a fuse should be used. The justification is that this type of tap fuse does not protect the tap, it protects the remainder of the distribution feeder from a fault on the tap.

The extent of the outage can be minimized by limiting the size and length of the affected line. The shorter line segment minimizes the number of customers affected and minimizes the time required to patrol the line and locate the fault.

A combination of a recloser and fuses, as shown in Figure 1, is typically used to provide protection against both transient and permanent faults.

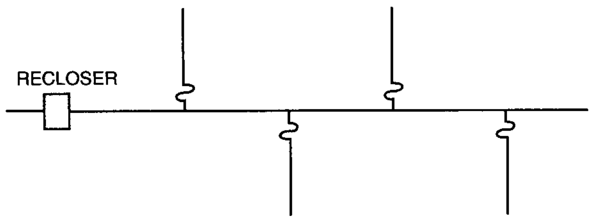


Figure 1.
Reclosers and fuses provide protection against transient and permanent faults.

The fast trip curve of the recloser is used to clear all transient faults on the main feeder and taps. For permanent faults on the taps, the recloser time-delay curve allows the tap fuse to clear, resulting in an outage on the tap only as shown in Figure 2.

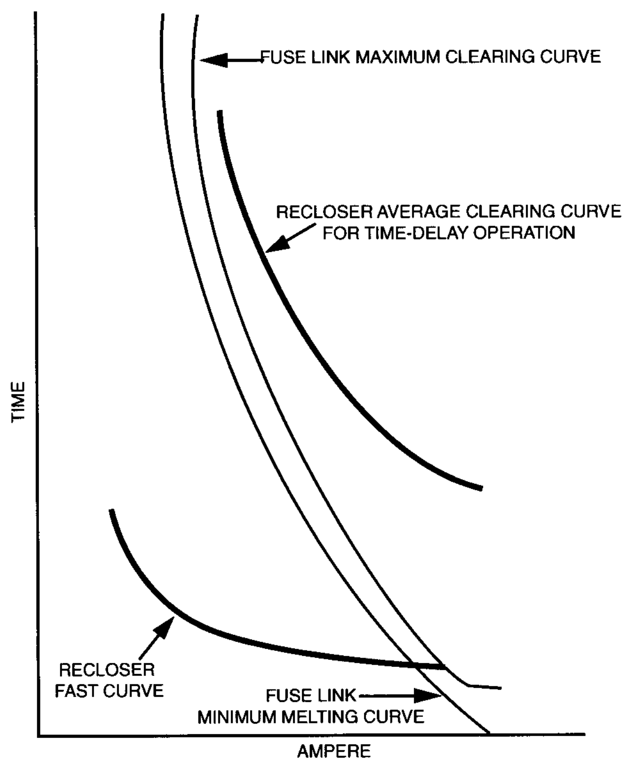


Figure 2.
Recloser/fuse link coordination.

Outage Rate Reduction Examples

The following examples describe how outage rates can be reduced by various approaches to using main-line sectionalizing devices, recloser/fuse coordination, and loop schemes.

Example 1

Use of Main-Line-Sectionalizing Device

Investigate outage rates for one fault at F1 and one fault at F2 as shown in Figure 3.

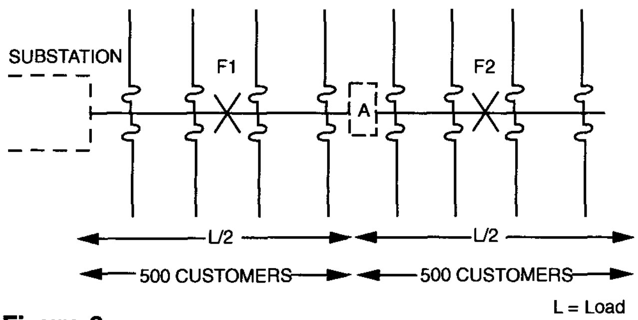


Figure 3.
Calculating reliability.

Each outage = 1 hour in length (time required to locate fault and restore service).

With No Line Recloser:

Fault at F1: 1000 customers x 1 hr. = 1000 cust. hrs.

Fault at F2: 1000 customers x 1 hr. = 1000 cust. hrs.

Outage Total = 2000 cust. hrs.

Option to Improve Service Reliability

Adding a recloser at point A, shown in Figure 3, as a main-line-sectionalizing device will reduce outage rates caused by faults on the main feeder.

With Recloser at A:

Fault at F1: 1000 customers x 1 hr. = 1000 cust. hrs.

Fault at F2: 500 customers x 1 hr. = 500 cust. hrs.

Outage Total = 1500 customer hours

Outage rate with line recloser equals 1500/2000 or 75% of rate without line recloser; or: 500/2000 = 25% reduction in outage rate.

Note: A sectionalizer can be substituted at point A to produce the same 25% reduction in outage rate.

The actual reduction in outage rate will be greater than the 25% calculated due to the shorter time required to patrol the line and locate the fault (crew must patrol only 1/2 of total line for fault at either F1 or F2).

Example 2

Circuit Breaker in Substation without Instantaneous Tripping

All faults on taps result in an outage due to fuse operation. Refer to Figure 4.

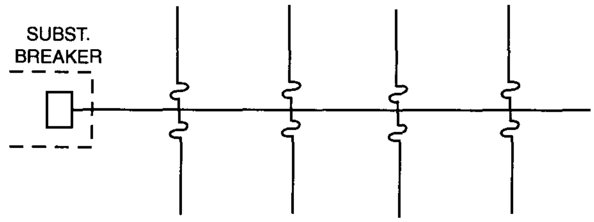


Figure 4.
Substation breaker set on all delay operations to lockout.

Options to Improve Service Reliability

1. Replace breaker with recloser.

   Outage rate should decrease by a rate equal to the ratio of transient faults to permanent faults on the system. Therefore, if 70% of faults are initially transient by nature, outage rates will decrease by 70%.

2. If committed to existing breaker protection, adding a recloser in line will still provide a dramatic decrease in outage rate:

Note: 25% decrease due to line sectionalizing as described in earlier systems.

Additional Benefits

Reduction in tap outages due to transient fault protection provided by recloser. 50% of taps x 70% transient fault rate = 35% reduction in outage rate.

Therefore, the total reduction in outage equals 25% +35% = 60% reduction in outage rate.

Example 3

Circuit Breaker in Substation with Fast and Delayed Relay Settings

A breaker utilizing a conventional relay setting of one instantaneous (INST) trip followed by time-delay trip operations, with the INST trip level set typically at 2 1/2 times the basic phase and ground trip settings, as shown in Figure 5.

Phase trip = 800 A, INST at 2000 A

Ground trip = 300 A, INST at 750 A

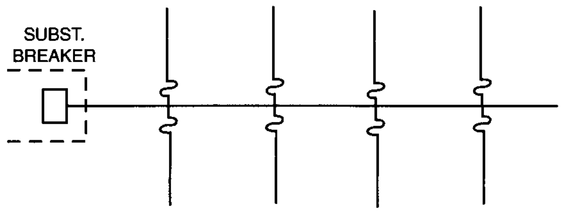


Figure 5.
Substation breaker with typical relay settings.

The 750 A ground trip instantaneous setting generally will not provide reach for faults distant from the substation; thus all transient faults occurring at these locations and all faults below 750 A magnitude on any tap will result in an outage.

Options to Improve Service Reliability

1. Replace breaker with recloser using conventional recloser sequence providing fast tripping at basic trip levels selected. With electronic control the fast Time-Current Curve (TCC) can be selected with adequate time delay near minimum trip to prevent any nuisance trips. Sequence coordination feature can be used for even better coordination if any down-line reclosers are used.

   The reduction in outage rate is dependent on the parameter of the circuit – how many faults below 750 A (as an example) are experienced. For a moderately long feeder with lengthy taps, a 50% reduction in the outage rate may be reasonable.

2. Add a recloser in line; even without breaker change-out, it will still provide dramatic improvement. The line recloser provides a 25% reduction in outage rate plus the reduction in outages on the taps due to the increased reach of the recloser.

3. Add a recloser in the line as shown in Figure 6. This will provide the 25% reduction in the outage rate as described earlier, plus some added improvement due to the added reach (or sensitivity) afforded by the more sensitive trip settings of the line recloser.

Note: It is generally very difficult, or impossible, for any substation device to be set to provide reach for protection to the ends of all taps.

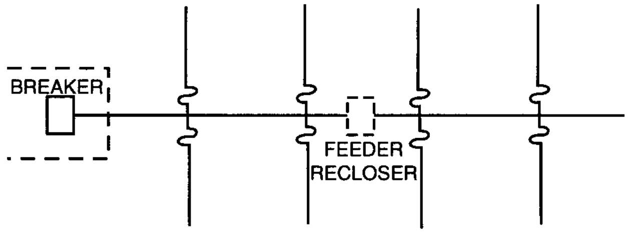


Figure 6.
Feeder recloser with conventional recloser settings.

Example 4

Loop Schemes

For the highest level of service reliability, some utilities have chosen loop schemes. The following example shows the improvement in service reliability that can be accomplished by midpoint sectionalizing and addition of a tie recloser between feeders.

Assume one fault at each section, for one hour duration each, as shown in Figure 7.

Fault at F1: 1000 customers x 1 hr. = 1000 cust. hrs.

Fault at F2: 1000 customers x 1 hr. = 1000 cust. hrs.

Fault at F3: 1000 customers x 1 hr. = 1000 cust. hrs.

Fault at F4: 1000 customers x 1 hr. = 1000 cust. hrs.

Outage Total = 4000 cust. hrs.

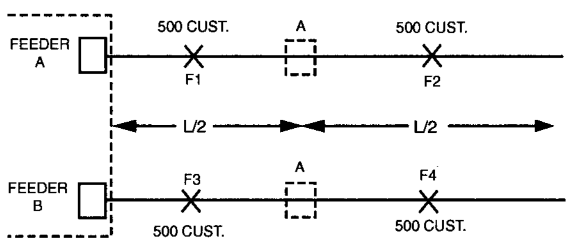


Figure 7.
Typical recloser-protected feeders without midpoint sectionalizing.

Options to Improve Service Reliability

Refer to Figure 8 and assume one fault at each section, for one hour duration, to show the effects of midpoint sectionalizing.

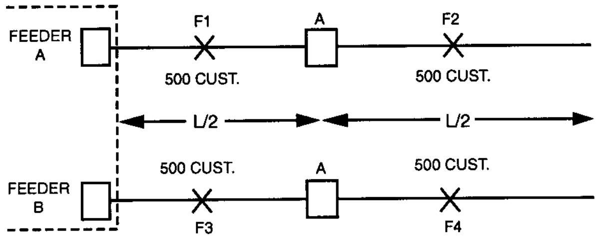


Figure 8.
Reclosers at midpoint of feeders.

Fault at F1: 1000 customers x 1 hr = 1000 cust. hrs.

Fault at F2: 500 customers x 1 hr = 500 cust. hrs.

Fault at F3: 1000 customers x 1 hr = 1000 cust. hrs.

Fault at F4: 500 customers at 1 hr. = 50 cust. hrs.

Outage Total = 3000 cust. hrs. (25% reduction)

Add a normally open tie recloser between feeders as shown in Figure 9, set to close upon loss of voltage from either side. The midpoint reclosers will be sectionalizing type reclosers, set to automatically open for loss of voltage from their source side.

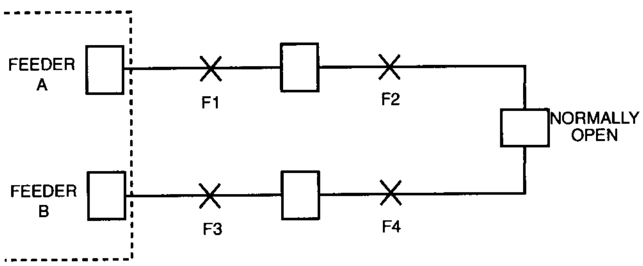


Figure 9.
Normally open tie recloser between feeders.

Fault at F1: 500 customers x 1 hr. = 500 cust. hrs.

Fault at F2: 500 customers x 1 hr. = 500 cust. hrs.

Fault at F3: 500 customers x 1 hr. = 500 cust. hrs.

Fault at F4: 500 customers x 1 hr. = 500 cust. hrs.

Outage Total = 2000 cust. hrs.

Adding a tie recloser as shown in Figure 9 and operating the midpoint reclosers as sectionalizing reclosers has resulted in a 33 1/3% reduction in customer outage: (3000–2000)/4000 = 33 1/3%.

Adding the three reclosers as shown in Figure 9 to the two feeders has reduced the outage rate to 50% of the original: (4000–2000)/4000 = 50%.

Example 5

Application of Recloser at Feeder Tap

Assume the reach of recloser A extends to point D on the tap as shown in Figure 10.

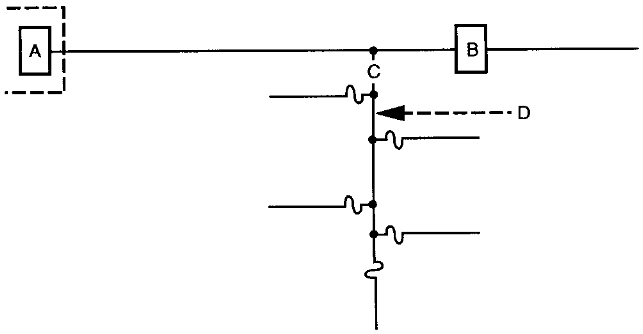


Figure 10.
Feeder tap without recloser protection.

If a fuse is used at location C:

1. Any transient fault on the main tap line beyond location D will cause the fuse at C to operate, resulting in an outage on the entire tap for a fault that was initially transient.
2. Service restoration can be delayed since crew may spend considerable time looking for a fault that no longer exists.
3. For a transient fault beyond any of the downline fuses, the downline fuse will operate, again resulting in a unnecessary outage for a fault that was initially transient. Use of a recloser at location C can normally be sized to provide reach for the entire tap. The fast trip of the recloser (as shown in Figure 2) will then clear transient faults, the reclosing operation then restoring service to all customers on the tap.

Underground Distribution

Reliability comparisons between overhead and underground feeders and distribution systems present a unique problem. Underground installation is more costly than overhead. Since there is no exposure to wind, trees, or ice, an underground system has few transient faults. This means there is no need for fast tripping or reclosing operations. Typically, protection at the substation consists of a single time-delay trip operation and lock open.

When a fault does occur, the outage duration can be long. It takes time to patrol the line and locate the fault. Equipment or cable repair can require considerably more time than equivalent overhead equipment repair. Fewer outages in an underground system means a lower SAIFI ratio, while significantly longer repair times will drive the SAIDI ratio up. The end result may be an unacceptable average outage ratio.

Option to Improve Service Reliability

The addition of a midpoint fault-sensing and interrupting device can be used to reduce the number of customers affected and reduce the time required for fault location.

System Automation

After protective devices are properly applied on a distribution system, the next higher level of system reliability can be achieved by automating the entire system for remote identification of faulted sections and rapid isolation of these sections by means of remote switching operations.

Remote identification of the faulted section eliminates the time required for line patrol. The remote switching function allows the faulted line to be isolated and service restored to all other line sections (assuming availability of an alternate feed to the remote sections) in less than 2 minutes. Thus, the outage is limited to only the faulted portion of the line.

Figure 11 illustrates a distribution system using both switches and line reclosers that can all be operated remotely.

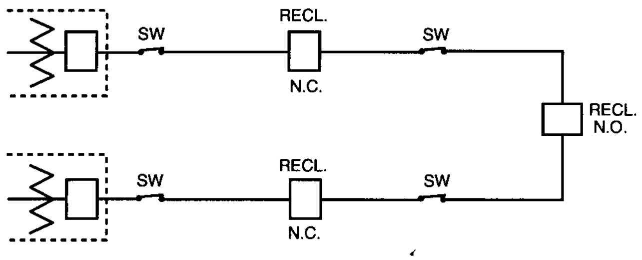


Figure 11.
Automated distribution system.

For this automated operation, switches have been developed that have stored energy operators (allowing remote switching without power at the switch location) and fault indicators to provide remote indication of fault location. The use of switches allows more sectionalizing points on the feeder without adding any steps of coordination. Reclosers are used to provide immediate local fault clearing capabilities that are independent of the communication system or remote computer control.

Summary

Increased usage of electricity has led to the need to increase distribution system voltages. Utilization of these higher distribution voltages has resulted in decreased system reliability and higher customer outage rates. Efficient application of reclosers and sectionalizers can provide dramatic improvements in distribution system reliability.

Using reclosers to provide transient fault protection on the entire distribution system can improve outage rates by 50–90%. Reclosers or sectionalizers used as main-line-sectionalizing devices can improve outage rates an additional 25%.

Even greater service continuity can be achieved by using nearby feeders as backup supplies. By using reclosers or sectionalizers as normally open feeder ties with local supervisory controls, outage rates can be improved by an additional 50% over unsectionalized systems.

Additional improvements in distribution system reliability can be obtained through the application of supervisory control or distribution automation.

Appendix B
Electric Utility Infrastructure Inspection Programs

Associated with this investigation, Staff reviewed AmerenUE's infrastructure inspection and maintenance programs. Not surprisingly, this topic overlaps somewhat with the reliability discussions in Appendix A as infrastructure inspection and maintenance programs impact reliability. As described in Appendix A, AmerenUE's reliability maintenance and enhancement programs include the following: Overhead Circuit Inspections, Tap Fusing, Recloser/Sectionalization, Division Reliability Reviews and Weekly Device Outage Reviews. In addition to these formalized programs, AmerenUE also responds to individual customer requests related to frequent momentary outages and customer-specific concerns about general reliability. These programs, to differing degrees, all relate back to infrastructure inspection and maintenance programs.

Associated with its investigation, Staff contacted sixteen nearby states to determine how many of them have rules that require their electric utilities to inspect their entire infrastructure on some specified maximum timeframe. Staff found that of the sixteen states contacted, four of them require system inspections on specified maximum timeframes. After examining AmerenUE's programs and contacting the other investor-owned electric utilities in Missouri, Staff believes that it is appropriate to implement an infrastructure inspection reporting rule at this time. AmerenUE, as well as some other electric utilities, have recently implemented a number of programs to inspect and maintain their electricity delivery infrastructure. This rule would provide for regular reporting on the structure, objectives, funding and status of these programs. A draft rule that would accomplish this is attached in Appendix E.

Recommendation: Adopt and implement a Commission rule that requires electric utilities to annually submit a report on the structure, objectives, status, and funding of their transmission and distribution infrastructure inspection and maintenance programs.

One program that was not addressed in Appendix A was AmerenUE's utility pole inspection program. Associated with this investigation Staff has carefully reviewed AmerenUE's pole inspection program. As noted earlier in this report, Staff did not find that AmerenUE's infrastructure, including utility poles, exhibited an abnormally high failure rate in the July 19th and 21st storms.

AmerenUE's transmission, sub-transmission and backbone feeder system poles currently fall under specific inspection programs that assess all poles that are older than fifteen years on regular intervals that do not exceed ten years. Many of the aspects of these inspection programs implement procedures described in RUS Bulletin 1730B-121. Attached to the end of this appendix is the U.S. Dept. of Agriculture's, Rural Utilities Service (RUS), Bulletin 1730B-121. This bulletin focuses on utility pole inspection and maintenance programs. The purpose of this document is to provide RUS borrowers with information and guidance for establishing or sustaining a continuing program of pole maintenance. In evaluating pole inspection programs, Staff found that electric utility programs typically implement many of the concepts outlined in this bulletin.

AmerenUE's formalized inspection program for sub-transmission poles began in 1991 and its inspection program for feeder poles began in 1997. These programs, including AmerenUE's transmission pole inspection program, are structured to achieve inspections of these poles on a ten year cycle and AmerenUE has approximately 220,000 poles under these programs. These pole inspection programs do not extend down to non-feeder distribution poles. AmerenUE has approximately 550,000 non-feeder distribution poles that are currently inspected under AmerenUE's Overhead Circuit Inspection and Pole Attachment Audit Programs.

In this investigation Staff has not concluded that AmerenUE's current program for assessing distribution poles is insufficient. Staff is however concerned with the average age of AmerenUE's distribution poles, their expected useful life and the current rejection and replacement rate of these poles. Staff therefore recommends that AmerenUE assess its current program according to the following recommendation:

Recommendation: AmerenUE should assess its current non-feeder distribution pole inspection programs and report to Staff within 180 days on which of the following approaches it believes is appropriate regarding maintenance and inspection of these distribution poles:

1) **Enhance its existing distribution pole audit programs (overhead circuit inspection program and pole attachment audits) to increase the likelihood that these audits will identify distribution poles that should be rejected or receive additional treatment to extend their useful life;**
2) **Implement a new program specifically for inspection of distribution poles that is structured to have a high likelihood of identifying poles that should be rejected or receive additional treatment to extend their useful life;**
3) **Demonstrate that the current rate of replacement of distribution poles is consistent with the anticipated average age of currently installed distribution poles and their expected useful life, and therefore, no distribution pole audit program changes are appropriate at this time; or**
4) **Propose an alternate approach to those programs noted above.**

UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

BULLETIN 1730B-121

SUBJECT: Pole Inspection and Maintenance

TO: All Electric Borrowers

EFFECTIVE DATE: Date of Approval

EXPIRATION DATE: Seven years from effective date

OFFICE OF PRIMARY INTEREST: Transmission Branch, Electric Staff Division

FILING INSTRUCTIONS: This bulletin replaces REA Bulletin 161-4, "Pole Inspection and Maintenance," dated October 17, 1974. File with 7 CFR Part 1730.

PURPOSE: To provide RUS borrowers with information and guidance for establishing or sustaining a continuing program of pole maintenance**.**

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ABBREVIATIONS

ACA	-	Ammoniacal copper arsenate
ACZA	-	Ammoniacal copper zinc arsenate
ANSI	-	American National Standards Institute
AWPA	-	American Wood Preservers' Association
CCA	-	Chromated copper arsenate
EPA	-	Environmental Protection Agency
EPRI	-	Electric Power Research Institute
NaMDC	-	N-Methyldithiocarbamate
NESC	-	National Electrical Safety Code
MITC	-	Methylisothiocyanate
OCF	-	Overload Capacity Factor
pcf	-	pounds per cubic foot
REA	-	Rural Electrification Administration
RUS	-	Rural Utilities Service

DEFINITIONS

Accelerometer – A device used to measure acceleration.

Fumigants – Preservatives delivered into a pole in a liquid or solid form that vaporize over time sending fumes throughout a given pole section.

Fungi – Lower life plant form which uses wood for food to sustain life.

Incipient decay – The early stage of decay that has not proceeded far enough to soften or otherwise perceptibly impair the hardness of wood. It is usually accompanied by a slight discoloration or bleaching of the wood.

1. PURPOSE: The purpose of this guide bulletin is to furnish information and guidance to Rural Utilities Service (RUS) electric borrowers in establishing or sustaining a continuing program of effective, ongoing pole maintenance. Discussed are methods and procedures for inspecting and maintenance of standing poles and for determining the minimum required groundline circumferences for distribution and transmission poles.

2. GENERAL DISCUSSION OF POLE DECAY: Decay of a treated pole is usually a gradual deterioration caused by fungi and other low forms of plant life. Damage by insect attack (termites, ants and wood borers) is usually considered jointly with decay because preservative treatment of wood protects against both fungi and insects. In most cases, the decay of creosote and pentachlorophenol treated poles occurs just below the groundline where conditions of moisture, temperature and air are most favorable for growth of fungi. Decay factors affecting pole life are discussed below.

2.1 Pole Species: Of the millions of poles installed on RUS borrowers' systems, about 85 percent are deep sapwood southern pines. Untreated, southern pine sapwood is especially vulnerable to attack by wood destroying fungi, termites, and carpenter ants. In the Gulf States, where temperature and moisture are most favorable for fungi growth and environmentally favored by termites and carpenter ants, pole replacement time of an untreated southern pine pole would be 2 to 3 years. In areas of lower rainfall and average lower temperatures, the time to pole failure for untreated pine would increase to 5 to 10 years.

The bulk of the remaining pole population is classified as the western species, comprised of Douglas fir, western red cedar, lodgepole pine, and ponderosa pine. The northern pine species, red and jack, are used in relatively small amounts.

Adequate preservative treatment (pole conditioning and preservative penetration and retention) provides relatively good protection of pole sapwood and the underlying heartwood. Heartwood of most species varies widely in decay resistance, and is almost impossible to treat with preservatives. Species resistance to decay are classified as follows:

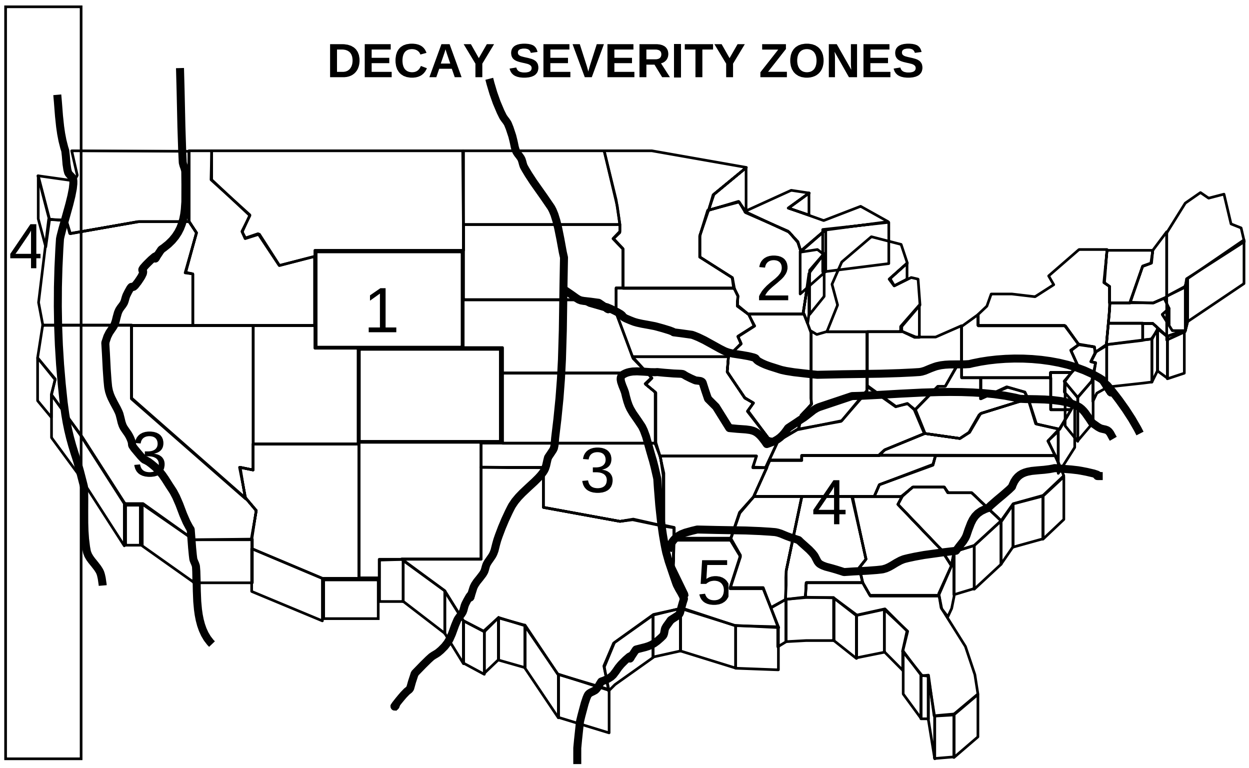
Durable – Western red cedar.
Moderately Durable – Douglas fir and most of the pines.
Least Durable – Lodgepole pine. (The use of this species has been limited primarily to the Mountain States areas.)

2.2 Preservative Treatments: There are two general classes of preservative treatment, oil-borne (creosote), pentachlorophenol (penta) in petroleum, and Copper Naphthenate) and water-borne (arsenates of copper). Creosote was the only preservative used on rural system poles until 1947, when post-war chemical shortages prompted the introduction of penta and Copper Napthenate. Both of these preservatives were dissolved in fuel oils from petroleum or mixed with creosote. Today, these preservatives are blended with petroleum distillates.

Penta is now the most widely used pole preservative. Where decay problems have occurred, they have not been attributed to any deficiencies of the preservative, but to one or more of the following: (1) loss of solvent carrier due to gravitation and bleeding, (2) poor conditioning of the poles, and (3) loss of dissolved penta to retentions below the effective threshold. To overcome these deficiencies, treatments and quality control have been improved.

Wood preservatives used in water-borne solutions include ammoniacal copper zinc arsenate (ACZA), and chromated copper arsenate (CCA) (types A, B, and C). These preservatives are often employed when cleanliness and paintability of the treated wood are required. Several formulations involving combinations of copper, chromium, and arsenic have shown high resistance to leaching and very good performance in service. Both ACZA and CCA are included in many product specifications for wood building foundations, building poles, utility poles, marine piles, and piles for land and fresh water use. Treatment usually takes place at ambient temperature. During treatment of Douglas fir, experience has shown that care needs to be taken to ensure that the pole is sterilized.

2.3 Decay Zones: The map on the following page details the five Decay Severity Zones of the United States. These zones were originally based on summer humidity and temperature information and later on a pole performance study conducted by the Rural Electrification Administration (REA). Decay severity ranges from least severe in Zone 1 to most severe in Zone 5. Service life records, individual experience, and/or a planned sample inspection should indicate if the decay hazard for a particular system is typical of the zone in which the system is located.



2.4 Types of Decay: After installation, decay organisms may invade the heartwood of poles through the poorly treated sapwood zones, checks, or woodpecker holes. Internal decay may occur in pole tops cut after treatment and in holes bored in the field where supplementary treatment has been neglected. Insufficient amount of preservative or migration of oil-type preservatives are the principal causes of external decay in southern pine poles. Poles in storage can decay because being stacked horizontally can encourage migration of the oil to the low side, depleting oil and preservative from the top side. For this reason, it is recommended that poles in storage are rolled annually to eliminate depletion of preservative from the top side.

Internal decay may be found in southern pine poles that were not properly conditioned or in which penetration or the amount (retention) of preservative is lacking entirely or insufficient. Internal decay of the western species usually involves the heartwood which has been improperly seasoned prior to treatment.

External decay above ground, more commonly known as “shell rot”, occurs frequently in butt-treated western red cedars after 12-15 years of service.

3. PLANNED INSPECTION AND MAINTENANCE PROGRAM: The purpose of a planned inspection program is to reveal and remove danger poles and to identify poles which are in early stages of decay so that corrective action can be taken. The end result of the inspection program is the establishment of a continuing maintenance program for extending the average service life of all poles on the system. The steps in developing a planned pole inspection and maintenance program are outlined below:

3.1 Spot Checking: Spot checking is the initial step in developing a planned pole inspection and maintenance program. Spot checking is a method of sampling representative groups of poles on a system to determine the extent of pole decay and to establish priority candidates for the pole maintenance measures of the program. A general recommendation is to inspect a 1,000-pole sample, made up of continuous pole line groupings of 50 to 100 poles in several areas of the system. The sample should be representative of the poles in place. For instance, all the poles on a line circuit or a map section should be inspected as a unit and not just the poles of a certain age group. The inspection of the sample should be complete, consisting of hammer sounding, boring, and excavation as described in Section 4. Field data should be collected on the sample as to age, supplier, extent of decay, etc.

The data should be analyzed to determine the areas having the most severe decay conditions and to establish priorities for a pole-by-pole inspection of the entire system. It may be desirable to take additional samples on other portions or areas of the system to determine if the severity of decay is significantly different to warrant the establishment of an accelerated pole inspection and maintenance program for that portion of the system. The results of the spot check will aid in scheduling a continuous pole inspection and maintenance program at a rate commensurate with the incidence of decay.

3.2 Scheduling the Inspection and Maintenance Program: If an ongoing maintenance program is not in place, the suggested timing for initial pole-to-pole inspection and subsequent re-inspection is shown in Table 3-1. Supplementary treatment is performed where necessary after the initial inspection.

Decay Zone	Initial Inspection	Subsequent Re-inspection	Percent of Total Poles Inspected Each Year
1	12 – 15 Yrs	12 Yrs	8.3%
2 & 3	10 – 12 Yrs	10 Yrs	10.0%
4 & 5	8 – 10 Yrs	8 Yrs	12.5%

TABLE 3-1 – Recommended Pole Inspection Schedules

The vulnerability of poles to decay is generally proportionate to the decay zone in which they are installed. As a general recommendation, the initial pole-by-pole inspection program should be inaugurated at a yearly rate of 10 percent of the poles on the entire system when the average age of the poles reaches 10 years. If a spot check indicated that decay is advanced in 1 percent of the pole sample, the inspection and maintenance program should be accelerated so that a higher percentage of poles are inspected and treated sooner than the figures shown in Table 3-1. If the decay rate is low for a particular decay zone or area of the system, the pole-by-pole inspection can be adjusted accordingly. Historical inspection data indicates that the ratio between the decaying/serviceable poles to reject poles in the 10-15 year age group is about six or more to one. In a 30-year age group, the ratio was down to about one to one or less. In the latter group, the survivors have more than sufficient residual preservative to protect them indefinitely. The poorly treated poles in the 30-year old group usually have already decayed and been replaced.

The greatest economic benefit from regular inspection is in locating the decaying/ serviceable group. Treatment of poles in this group can extend pole life, thereby avoiding the cost of emergency replacement. Inspection and proper maintenance can more than pay dividends by extending the serviceable life of the poles. With the costs of replacing poles rising, the economics of extending the service life become more favorable.

3.3 Setting Up the Program: The pole-by-pole inspection and maintenance work may be done by system employees or by contracting with an organization specializing in this type of work. The choice should be made on the basis of the amount of work to be done, availability, depth of trained people on staff, and a comparison of the costs. Developing the necessary skills in the system’s own crews may require considerable time and be contingent upon the availability of an experienced inspector to train system employees. Therefore, qualified contract crews may be preferable for this work in many instances. To be considered qualified, the individual should have inspected, at a minimum, 5,000 poles under a qualified inspector and another 5,000 poles independently, but under close supervision. When the inspection program is underway, the work of the person chosen to inspect should be checked every week or two by the system’s representative and the inspector’s supervisor. The best way to check on inspector’s work is to select at random about 10 poles inspected in the last few weeks, and perform a complete re-inspection of the 10 poles. The re-inspection should include: re-excavating, removal of paper and treatment, testing for hollow sounds, taking a boring, checking soft surface wood, re-measuring the pole, rechecking the calculations, then retreating and backfilling. If any serious first inspection errors are discovered, all work performed by the inspection between these spot checks should be re-inspected.

The pole inspection and maintenance program may result in a large number of replacements. If the reject rate is high, the system's crews may not be able to replace rejected poles in a reasonable time because of other work. The temporary addition of skilled personnel for inspection or pole replacement may be required. It is generally necessary to use at least one crew full time to keep up with the pole inspector. An average pole inspector can check 150-200 poles per week or 800 poles per month. It is desirable to have one person responsible for supervision and coordination.

3.4 Re-inspections: Information obtained during the first pole-y-pole inspection can serve as the basis for scheduling subsequent inspections. It is recommended that a re-inspection be made ever 8 to 12 years as mentioned in paragraph 3.2, according to the decay zone and severity of decay. These recommendations should be modified by personal experience, but the intervals should not be extended by more than 3 years. It is advisable to recheck some poles which have been groundline treated at intervals sooner than recommended in paragraph 3.2 to assure field applied treatment is working properly and recommended time intervals for re-inspection can be trusted.

4. INSPECTION METHODS: There are varying types of inspection, each with a different level of accuracy and cost. Inspection methods with low accuracy require more frequent re-inspection than methods which are detailed and more accurate.

4.1 Visual Inspection: Visual inspection is the easiest and lowest cost method for inspecting poles and has the lowest accuracy. Since most decay is underground or internal, this method will not detect the majority of any existing decay. Obvious data can be collected on each specific structure, such as the above ground relative condition of the pole, crossarm, and hardware. However, because this method misses the most crucial part of a true pole inspection and maintenance program, this method is not recommended.

4.2 Sound and Bore: This method involves striking a pole with a hammer from groundline to as high as the inspector can reach and detecting voids by a hollow sound. An experienced inspector can tell a great deal about a pole by listening to the sounds and noticing the feel of the hammer. The hammer rebounds more from a solid pole than when hitting a section that has an internal decay pocket. The internal pocket also causes a sound that is dull compared to the crisp sound of a solid pole section.

Some inspection methods require all poles to be bored, while others require boring only when decay is suspected. Boring is usually done with either an incremental borer or power drill with a 3/8" bit. An experienced inspector will notice a change in resistance against the drill when it contacts decayed wood. The shaving or the borings can be examined to determine the condition of the wood, and the borings can be analyzed for penetration and retention.

When voids are discovered, a shell thickness indicator can be used to measure the extent of the voids. This information can be used to estimate the reduction in strength caused by the void, as discussed in Section 8.

The effectiveness of the sound and bore method varies with different species. For southern yellow pine poles, which represent a majority of the poles in North America, decay normally is established first on the outside shell below ground. The decay moves inward and then upward to sections above ground. By the time sound and bore inspection methods can detect internal decay pockets above ground, the pole is likely to have extensive deterioration below ground.

The sound and bore method is more effective with Douglas fir and western red cedar poles. Decay on these poles is likely to begin internally near the groundline, or in the case of Douglas fir, above the groundline. Therefore, sounding and boring can identify at least some decay at a stage before the groundline section is severely damaged.

All borings should be plugged with a treated wood plug which is properly sized for the respective hole.

Sound and bore method is recommended for the inspection of Douglas fir and western red cedar poles but should be used in combination with excavation for southern pine poles.

4.3 <u>Excavation</u>: The effectiveness of the sound and bore inspection is greatly increased when excavation is added to the process. Excavation exposes the most susceptible section of the pole for inspection. For southern yellow pine, this is particularly true since decay begins externally and below ground.

Poles should be excavated to a depth of 18 inches in most locations. Deep excavation may be required in dry climates. After excavation, the exposed pole surface should be scraped clean to detect early surface decay. The best results can be obtained by using a triangular scraper.

Shell rot and external decay pockets should be removed from the pole using a specially designed chipper tool. Axes or hatchets should never be used for this application. The remaining pole section should be measured to determine if the pole has sufficient strength with the reduced circumference. Tables 2, 3, and 4 on page 19, assist in determining the effectiveness.

After complete inspection and application of preservative treatment, the pole is backfilled by tamping every 6 to 8 inches of dirt at a time until the hole is filled. The backfill should mound up around the pole to allow for future settling and drainage away from the pole.

5. ADDITIONAL INSPECTION TOOLS AND METHODS: Additional equipment and methods are available which can be incorporated into the inspection process.

5.1 Shigometer: The Shigometer uses electrical resistance to detect incipient decay before it can be detected with the human eye or sensed with a drill. During the decay process, negative ions form in the infected wood and cause the electrical resistant to lower. The Shigometer measures electrical resistance and detects incipient decay when there are sudden drops in resistance readings.

The Shigometer employees test leads consisting of a twisted pair of insulated wires with bare metal tips. Both metal tips are slowly inserted into a 7/64" diameter hole bored into the pole. The instrument delivers an electric current pulse through the probes each second. The resistance of the wood tissue is measured between the contact points of the two tips.

By detecting incipient decay, the inspector can decide what further steps of inspection and preservative treatments to take.

5.2 Poletest: Poletest is a sonic instrument developed through research funded by the Electric Power Research Institute. During the development of this instrument, spectral analyses of sound waves that traveled through cross sections at various locations were compared to the actual breaking strength of poles. The end result of the research is a field test device that provides a statistically reliable direct readout of the strength of a pole at a specific cross section.

The intent of the Poletest instrument is to provide a strength assessment for individual poles as opposed to assuming pole designated fiber stresses of the American National Standards Institute (NASI) 05.1. However, Poletest is not a substitute for traditional inspection because it does not detect decay, especially below ground. Measured strength values can be used to assist in determining when pole replacement is necessary.

5.3 De-K-Tector: The De-K-Tector and other waveform analysis instruments analyze sound wave patterns as they travel through a cross section of a pole. A calibrated mechanical striker impacts the pole and the sound wave or vibration wave caused by the impact is sensed by an accelerometer on the opposite side of the poles.

The waveform that is detected by the accelerometer is electronically divided into high and low frequency components. Research has shown high frequencies are absorbed more by decayed wood. Therefore, a reading with a low magnitude, high frequency component would indicate a "questionable" pole because decay absorbed some of the high frequency component before the waveform reaches the opposite side of the pole. That pole would need further inspection by traditional methods.

6. RESULTS OF WOOD POLE INSPECTION

6.1 Inspection Results: Inspection results should be used to update pole plant records, evaluate pole conditions, plan future inspection and maintenance actions, and provide information for system map revisions. The inspection process will result in identifying the condition of each individual distribution and transmission pole.

In general, ANSI C2, "National Electric Safety Code (NESC)," requires that if structure strength deteriorates to the level of the overload factors required at replacement, the structure shall be replaced or rehabilitated. The inspection results should be replaced or rehabilitated. The inspection results should indicate if a pole is "serviceable" or a "reject".

6.1.1 A pole is considered "serviceable" under any of the following conditions:

a. Large portion of completely sound wood exists.
b. Early stages of decay which have not reduced the pole strength below NESC requirements.
c. Pole condition is as stated in (1) or (2) but a defect in equipment may exist, such as a broken ground or loose guy wire. Equipment defects should be subsequently repaired.

6.1.2 Any pole that does not meet the above conditions should be classified as a "reject". Any of the following conditions are characteristics of rejects:

a. Decay, insect or mechanical damage has reduced pole strength at the groundline below NESC requirements.
b. Severe woodpecker hole damage has weakened the pole such that it is considered below NESC requirements.
c. Hazardous conditions exist above ground, such as split top.

6.1.3 Rejected poles may be classified further depending on the severity of the deterioration and whether they are reinforceable:

a. A "reinforceable reject" is any reject which is suitable for restoration of the groundline bending capacity with an industry acceptable method of reinforcement.

b. A "replacement" candidate is a rejected pole which is not suitable for necessary rehabilitation.

c. A "priority reject" is a reject pole that has such severe decay deterioration, it should be removed as soon as possible.

7. REMEDIAL TREATMENT

7.1 The purpose of remedial treatment of a standing pole is to interrupt the degradation by the addition of chemicals, such as pesticides, insecticides and fungicides, thereby extending the useful life of the structure. Treatment may be external groundline treatment or internal treatment.

7.2 Regulations and Licensing: Most states require applicators or job supervisors to obtain a pesticide applicator license. Testing for this license includes a "basic skills test" to show knowledge of the rules and regulations governing pesticides. Some states also give a "category test" which is specific to wood poles and wood preservation.

The uses of pesticides are classified by the United States Environmental Protection Agency (EPA) as either "general" or "restricted". A "general use" pesticide is not likely to harm humans or the environment when used a directed on the label. These pesticides may be purchased as applied without a pesticide applicator license. However, a manufacturer may choose not to make a product available for purchase by the general public.

A "restricted use" pesticide could cause human injury or environmental damage unless it is applied by competent personnel (certified applicators) who have shown their ability to use these pesticides safety and effectively. These wood preservatives can only be purchased and applied by someone who has a pesticide applicator license or whose immediate supervisor has a pesticide applicator license.

7.3 Groundline Treatment: All treated poles eventually lose resistance to decay, and groundline treatment provides an economical extension of their useful life. Experience has shown that groundline decay can be postponed almost indefinitely in cases where periodic inspection and maintenance programs are in effect. Groundline treatment is recommended under the following conditions:

a. Whenever a pole is excavated during an inspection, and the pole is sound or decay is not so far advanced that the pole has to be replaced or repaired.

b. Whenever a pole over 5 years old is reset, or

c. Whenever a used pole is installed as a replacement.

The two general types of external preservatives used for groundline treatment are either waterborne or oilborne. The fungi-toxic components of waterborne preservatives are water soluble while the oilborne preservatives carry oil soluble fungicides. There are formulations that contain both waterborne and oilborne solutions.

Sodium fluoride is the most commonly used water soluble active ingredient in remedial treatments. Historically, oilborne preservatives have included creosote and pentachlorophenol. However, use of penta in supplemental preservatives appears to be declining. In recent years, Copper Naphthenate has been used in external preservative pastes. Boron has also been introduced as an ingredient in a groundline paste.

Before application of external preservatives, decayed wood should be stripped from the pole and removed from the excavation. The preservative paste or grease is most commonly brushed onto the pole. A polyethylene backed paper is then wrapped around the treatment and stapled to the pole. The paper helps to facilitate the migration of the preservative into the critical outer shell.

7.4 Internal Treatment: The three basic types of preservatives used for internal treatment are liquids, fumigants, and solids.

7.4.1 Liquid Internal Preservative: Liquid internal preservatives should be applied by pressurized injection through a series of borings that lead to internal decay pockets or voids. Adequately saturating the pocket and surrounding wood should arrest existing decay or insect attack and prevent further degradation for an extended time.

Liquid internal preservatives contain water soluble or oil soluble active ingredients. Sodium fluoride is the principle active ingredient in the water based formulations. Moisture that is present in the pole will help facilitate diffusion of the active ingredients into the wood beyond a decay pocket.

Oil based internal preservatives most often incorporate Copper Naphthenate as an active ingredient with fuel oil or mineral spirits as the solvents. Since Copper Naphthenate is not soluble in water, it is likely to migrate into the surrounding wood only as far as the oil will travel.

7.4.2 Fumigants: Most of the fumigants in use for wood poles today were originally developed for agricultural purposes. Applying fumigants to soil will effectively sterilize the ground. Due to high levels of microorganisms and chemical activity in soil, the fumigants will degrade fairly rapidly and dissipate so that new crops can be planted in a short time.

These same fumigants do not degrade rapidly in wood and will remain affixed to sound wood cell structure for many years. Fumigants have also been found to migrate longitudinally in wood, several feet away from the point of application. This helps control decay in a large section of the pole. When the vapors migrate into a decay void, however, they may dissipate through associated checks and cracks. This reduces the long term effectiveness and requires more frequent application.

Registered pole fumigants include Sodium N-methyldithiocarbamate (NaMDC), Methylisothiocyanate (MITC), Chloropicrin and Vorlex. Vorlex has not yet been commercially used for utility poles, since it requires a closed application system. Chloropicrin is a very effective wood fumigant. However, the liquid has to be applied from pressurized cylinders, and the applicator has to wear a full-face air respirator.

NaMDC and MITC are the most widely used wood pole fumigants. NaMDC is soluble in water to a maximum amount of 32.7 percent. Treatment holes drilled in a wood pole are filled with the aqueous solution so the appropriate dosage is applied. Recommended dosages vary according to pole size. The NaMDC solution decomposes and generates MITC as the main fungi-toxic ingredient. The maximum theoretical amount of resultant MITC at ideal conditions is 18.5 percent by weight. The MITC vapors then migrate up and down the pole to help control decay.

Pure MITC is a solid below 94ºF and contains 97 percent active ingredient. Solid MITC sublimes directly into fumigant vapors. Avoiding the liquid stage helps to minimize loss of fumigant during application through checks and cracks. MITC is packaged in vials to facilitate installation. Just before placing the vial into a treatment hole, the cap is removed. As with any fumigant, application holes should be plugged with pressure treated plugs.

7.4.3 Solids: Currently, one solid preservative, a boron rod, is available in North America as a supplemental preservative treatment for wood poles. However, the American Wood Preservers' Association (AWPA) Standards do not include borates for ground contact applications like utility poles. Research and development continues in evaluating formulations of borates with other compounds.

7.5 Woodpecker Damage: Woodpecker damage is another problem that requires attention. Many methods have been used in attempts to prevent such damage, but nothing has been entirely successful.

It appears that a woodpecker selects a pole only by chance, and that the first hole invites further attack by other woodpeckers. For these reasons, it is good maintenance practice to seal up the smaller holes. Various materials are available for plugging the holes, and a wire mesh can be used to cover the plugged hole as well as large areas of a pole.

8. DETERMINING THE SERVICEABILITY OF DECAYED POLES

8.1 The decision to treat or replace a decayed pole depends upon the remaining strength or serviceability of the pole. The permissible reduced circumference of a pole is a good measure of serviceability. The following procedure may be used to assist in determining if a pole should be replaced or reinforced.

8.2 Decay Classifications: Decay at the groundline should be classified as:

a. General external decay.
b. External pocket.
c. Hollow heart or
d. Enclosed pocket.

8.3 Permissible Reduced Circumference Safety Factors: Wood pole lines are designed using designated fiber strengths and loads multiplied by an overload capacity factor (OCF). For tangent structures the NESC prescribes on OCF “when installed” (new) for Grade B construction (transmission lines) of 4.0 and requires replacement or rehabilitation if the OCF reaches below 2.67. For Grade C construction (usual distribution line grade of construction) the “when installed” OCF is 2.67 and replacement or rehabilitated OCF is 1.33.

Using Tables 1 through 4, on pages 17 and 19 of this bulletin, will give assistance in determining when replacement or rehabilitation is necessary. If the reduced circumference indicates a pole at or below the “at replacement” OCF, the pole should be replaced, splinted, stubbed immediately, or otherwise rehabilitated. Appendix A, of this bulletin, shows the typical pole stubbing detail for distribution poles. Poles are successfully rehabilitated using steel channels, fiberglass reinforcing and epoxy.

8.4 General Procedures for Using Tables 1, 2, 3, and 4:

8.4.1 General External Decay. After removing all decayed wood, measure the circumference above and below the decayed section to determine the original circumference. Then measure the reduced circumference at the decayed section. If the line is built to Grade B construction (transmission), enter the original circumference in the OCF 4.0 column of Table 1. Move right across from the original circumference column of Table 1 until you find the reduced circumference. Once you find the reduced circumference, read the OCF at the top of the column in which your reduced circumference ended. If this OCF meets or exceeds the 2.67 OCF column, replacement is not necessary. However, poles with values close to the minimum should be monitored frequently to ensure that the poles OCF does not fall below the minimum.

For Grade C construction (usually distribution) enter Table 1 using the original circumference in column 4, OCF 2.67. These poles have to stay above the values of the OCF 1.33 column.

8.4.2 External Pockets. Remove decayed wood and make measurements of the depth and width of the pocket. Measure the pole for the original circumference. Refer to Table 2 to determine the circumference reduction. Enter Table 1 with the original circumference and the reduced circumference to determine the current OCF.

8.4.3 Hollow Heart (Heart Rot). If hollow heart is found, determine the shell thickness and measure the original circumference of the pole. Refer to Table 3 to determine the circumference reduction. Enter Table 1 with the original circumference and the reduced circumference to determine the current OCF.

To determine the shell thickness, bore three holes (preferably of 1/4 -3/8-inch diameter), 120º apart; measure the shell thickness at each hole, and average the measurements. After shell thickness is determined, treat and plug holes with tightly fitting cylindrical wood plugs that have been treated with preservative. No transmission pole should remain in service with a shell thickness less than 3 inches.

8.4.4 Enclosed Pocket. An enclosed pocket is an off-center void as shown in Table 4, and its diameter should be measured by boring holes as described in section 8.4.3. Using the minimum thickness of the shell, refer to Table 4 for the reduction in circumference. Measure the original circumference. Enter Table 1 with the original circumference and the reduced circumference and determine the current OCF.

Table 1
Pole Circumference Overload Capacity Factors (OCF)

Original Circumference (Inches)	Reduced Circumference (Inches)						
OCF 4.0	OCF 3.5	OCF 3.0	OCF 2.67	OCF 2.5	OCF 2.0	OCF 1.5	OCF 1.33
30.0	28.7	27.3	26.1	25.6	23.8	21.6	20.7
31.0	29.7	28.2	27.0	26.5	24.6	22.3	21.4
32.0	30.6	29.1	27.8	27.4	25.4	23.0	22.1
33.0	31.6	30.0	28.7	28.3	26.2	23.8	22.8
34.0	32.5	30.9	29.6	29.1	27.0	24.5	23.5
35.0	33.5	31.8	30.5	29.9	27.8	25.2	24.2
36.0	34.4	32.7	31.4	30.8	28.6	25.9	24.9
37.0	35.4	33.6	32.3	31.6	29.4	26.6	25.6
38.0	36.3	34.5	33.1	32.5	30.2	27.4	26.3
39.0	37.3	35.4	34.0	33.3	31.0	28.1	27.0
40.0	38.3	36.3	34.9	34.2	31.8	28.8	27.7
41.0	39.2	37.3	35.8	35.1	32.5	29.5	28.4
42.0	40.2	38.2	36.7	35.9	33.3	30.2	29.0
43.0	41.1	39.1	37.5	36.8	34.1	31.0	29.7
44.0	42.1	40.0	38.4	37.6	34.9	31.7	30.4
45.0	43.0	40.9	39.3	38.5	35.7	32.4	31.1
46.0	44.0	41.8	40.2	39.3	36.5	33.1	31.8
47.0	45.0	42.7	41.0	40.2	37.3	33.8	32.5
48.0	45.9	43.6	41.9	41.0	38.1	34.6	33.2
49.0	46.9	44.5	42.8	41.9	38.9	35.3	33.9
50.0	47.8	45.4	43.6	42.7	39.7	36.0	34.6
51.0	48.8	46.3	44.5	43.6	40.5	36.7	35.3
52.0	49.7	47.2	45.4	44.5	41.3	37.4	36.0
53.0	50.7	48.2	46.3	45.3	42.1	38.2	36.7
54.0	51.6	49.1	47.1	46.2	42.9	38.9	37.4
55.0	52.6	50.0	48.0	47.0	43.7	39.6	38.1
56.0	53.6	50.9	48.9	47.9	44.4	40.3	38.7
57.0	54.5	51.8	49.8	48.7	45.2	41.0	39.4
58.0	55.5	52.7	50.6	49.6	46.0	41.8	40.1
59.0	56.4	53.6	51.5	50.4	46.8	42.5	40.8
60.0	57.4	54.5	52.4	51.3	47.6	43.2	41.5

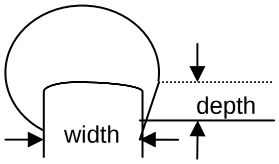


Table 2
Reduction in Measured Circumferences to Compensate for External Pockets

Pocket Width (ins)	1					2					3					4					5					6				
Pocket Depth (ins)	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Measured Circumference Of Pole (ins)	Reduction in Circumferences (ins)																													
20 to 30	1	1	2	-	-	2	2	3	-	-	2	3	4	-	-	3	4	5	-	-	4	6	8	-	-	6	8	-	-	-
30 to 40	1	1	1	2	-	1	2	2	3	3	2	3	4	4	4	2	4	5	5	6	3	5	6	7	8	5	7	8	9	-
40 to 50	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	4	5	6	3	4	5	6	7	3	5	6	7	8
50 to 60	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	3	4	5	3	4	4	5	6	3	4	5	6	7

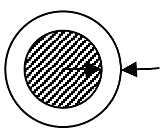


Table 3
Reduction in Measured Circumferences to Compensate For Hollow Heart

Measured Circumference Of Pole (ins)	Minimum Thickness of Shell (ins)					
	2	2.5	3	3.5	4	4.5
20 to 25	1	-	-	-	-	-
25 to 30	2	1	-	-	-	-
30 to 35	3	2	1	-	-	-
35 to 40	4	3	2	1	-	-
40 to 35	5	4	3	2	1	-
40 to 45	7	5	4	3	2	1

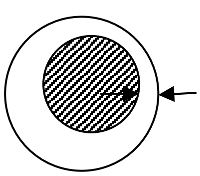
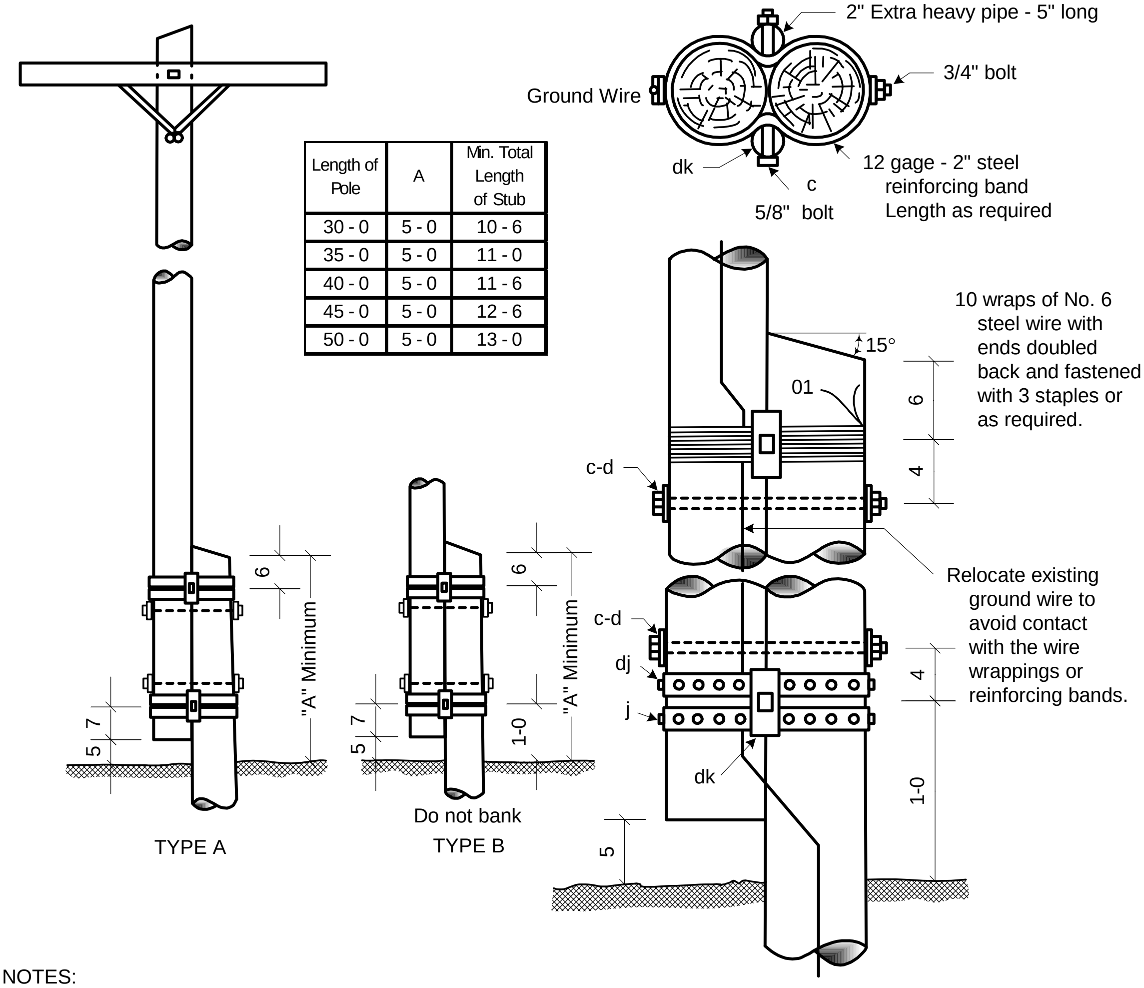


Table 4
Reduction in Measured Circumferences to Compensate For Enclosed Pockets

Diameter of Pocket (ins)	3			4			5		
Shell Thickness (ins)	1	2	3	1	2	3	1	2	3
Measured Circumferences Of Poles (ins)	Reduction in Circumferences (ins)								
20 to 30	2	1	-	3	1	-	4	2	-
30 to 40	2	1	1	3	1	1	4	2	1
40 to 50	2	1	1	3	2	1	4	3	1



Length of Pole	A	Min. Total Length of Stub
30 - 0	5 - 0	10 - 6
35 - 0	5 - 0	11 - 0
40 - 0	5 - 0	11 - 6
45 - 0	5 - 0	12 - 6
50 - 0	5 - 0	13 - 0

NOTES:
Use either wire wrapping or reinforcing band for stubbing material as required.
Position stub at side of pole (At right angle to direction of line and outisde of angle.)

ITEM	NO REQ'D	MATERIAL		ITEM	NO REQ'D	MATERIAL	
c	2	Bolt, machine. 3/4" x required length				Wire. No. 6 galvanized. as required.	
c	2	Bolt, machine. 5/8" x required length		01		Staples. as required.	
d	4	Washer. 2 1/4" x 2 1/4" x 3/16". 13/16" hole					
j	4	Screw, lag. 1/2" x 4"					
dj	4	Band, reinforcing. 12 gage x 2" x req'd length					
dk	4	Pipe spacer. 2" extra heavy x 5" long					

STUB REINFORCING OF DISTRIBUTION LINE POLES		
SCALE : NTS		DATE : 02/20/95
		M15

Metric Conversion Factors

To Convert From	To	Multiply By
Foot (ft)	Meter (m)	0.3048
Inch (in)	Centimeter (cm)	2.54
Degrees Fahrenheit (x°F)	Degrees Celsius (°C)	5/9 (x° - 32)

Appendix C

Electric Utility Third-Party Attachment Programs

Associated with this investigation, Staff reviewed AmerenUE's programs for assessing the impacts of third-party attachments to its utility poles. AmerenUE's formalized audit of third-party attachments began in 2001 and is operating on a five year cycle.

This program involves visual audits of third-party attachments on all AmerenUE poles to identify attachments AmerenUE was not aware of and may be non-compliant. All attachments are followed up on and either confirmed to be acceptable without modification or modified to be compliant. Compliance issues are assessed against NESC requirements and can be either clearance or pole strength related. Most attachments are assessed and found to be compliant; those that are not are typically in violation of clearance requirements not pole strength requirements. AmerenUE uses a contractor to assess third-party pole attachments.

AmerenUE completed the first cycle of its third-party attachment audits in January of this year. As a result of these audits, AmerenUE identified approximately 47,000 violations. Of these violations, 92% were at the pole versus midspan line clearance violations. Of the identified pole violations, approximately 98 to 99% were clearance violations. The small remaining percentage of violations was typically hardware related, and some of these required structural analyses due to a large bundle being attached to the pole.

AmerenUE's third-party attachment audits are structured to identify attachments to AmerenUE's utility poles that may not have been considered in existing calculations that confirmed the pole's acceptability for the loads it was intended to carry. Most third-party attachments are compliant and their approval by AmerenUE is completed before they are attached to the utility pole.

Any third-party that wishes to attach infrastructure to AmerenUE's poles must first determine what type of equipment and loads they plan to attach to AmerenUE's poles. The calculations to confirm that the loads on the pole do not exceed the pole's allowable stresses are certified by a professional engineer. They are then submitted to AmerenUE. Only attachments approved through this process are permissible on AmerenUE's poles.

Attached to the end of this appendix is an example pole attachment calculation package provided by AmerenUE. The first page of this attachment explains the six labeled attachments that follow the first page.

Ameren Pole Attachments

Post Attachment Audits

Ameren utilizes an independent contractor, Utilimap, to perform audits on 3rd party attachments on Ameren poles. Utilimap reports the results of the audits to Ameren via email notification. Data is reviewed through Utilimap's web-based portal.

Attachment 1 is a screen shot of the web portal showing poles audited relating to permit no. 2410.

Attachment 2 is a copy of the location detail of the pole audited.

Attachment 3 is a copy of the violation detail associated with the attachment on the pole.

Attachment 4 is an actual field photo of the pole audited.

Attachment Pole Loading

Ameren also utilizes Utilimap to perform field inspection, structural analysis, and recommended make-ready for all 3rd party attachment applications. Each pole attachment is field measured and loaded into a pole loading program called O-Calc. The program calculates the pole's structural loading with the proposed attachment added. In addition, clearances are measured to verify compliance with the NESC. Any make-ready required either due to loading or clearances is shown as a recommendation.

Attachment 5 is a copy of the analysis result summary reported back Ameren.

Attachment 6 is a copy of the O-Calc output for a particular pole on a permit application showing the loading calculations, 3D image of pole with attachments and an actual field photo of the pole.

ATTACHMENT 1

Utilimap Power Portal - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Address http://dev.utilimap.com:3100/postaudits/owner

Utilimap Power Portal

Poles by Attachment Owner

Goto page: 1 2 3 ... 230

next >>

pole #	permit	owner	city	intersection	latitude	longitude	violation	action
12227	2410	Charter	Hazelwood	Howdershell & Altavia			CATV	Show
12228	2410	Charter	Hazelwood	Howdershell & Lightfoot Dr			CATV	Show
280678	2410	Charter	Hazelwood	Howdershell & Lightfoot Dr			CATV	Show
12229	2410	Charter	Hazelwood	Howdershell & Tesson Rd			CATV	Show
12230	2410	Charter	Hazelwood	Howdershell & Tesson			CATV	Show
12231	2410	Charter	Hazelwood	Howdershell & Tesson Rd			CATV	Show

[redacted]

Local intranet

ATTACHMENT 2

Utilimap Power Portal

Date: Mon Jul 26 00:00:00 CDT 2004

Pole num seq: 1509-1504-19

Pole num: 12227

Permit num: 2410

Company: Charter

City: Hazelwood

Street: Howdershell

Cross street: Altavia

Loc add:

Lat: 0.000000000

Long: 0.000000000

Violation: CATV

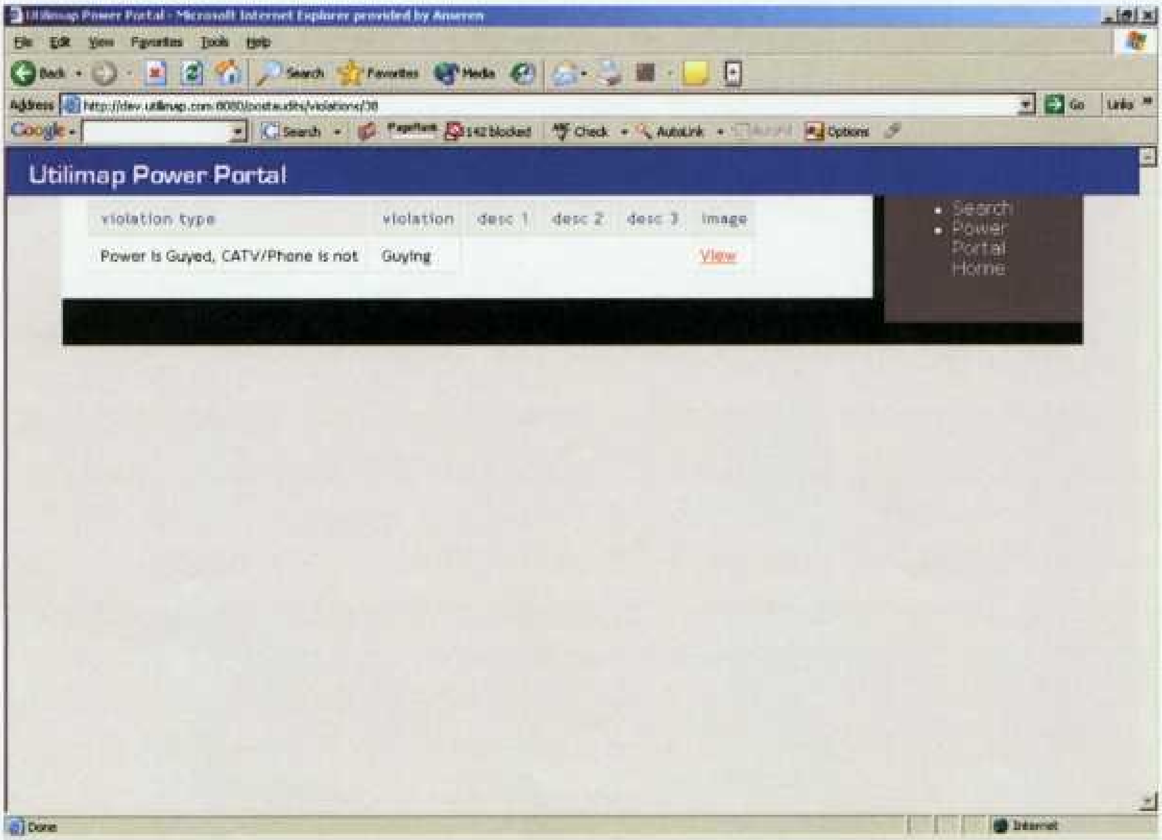
Violation other:

Viol category:

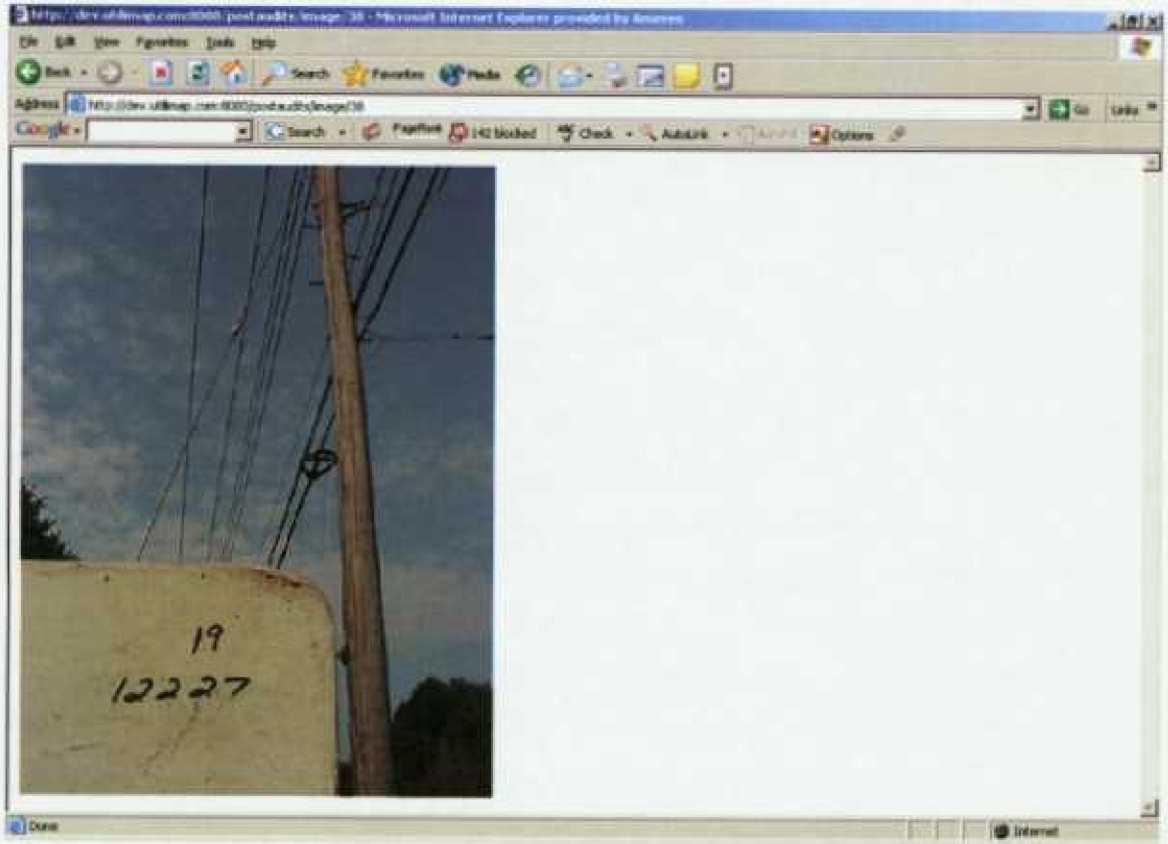
Back

- Search
- Power Portal Home

ATTACHMENT 3



ATTACHMENT 4



Utilimap Corporation
1053 Headquarters Park
Fenton, MO 63026
Ph: 636-533-4018
Fax: 636-533-4056

Total New Builds

12

The recommendations on this "make-ready" document are based on field measurements and pole load analysis calculations. They are not intended to be detailed engineering instructions for construction. The attaching party is responsible for verifying actual field conditions and developing details for construction prior to attachment in accordance with the NESC, local ordinances and the appropriate utility requirements.

Engineer Seal

STATE OF MISSOURI
KENNETH W. ROBB
NUMBER
PE-[redacted]
PROFESSIONAL ENGINEER

Kenneth W. Robb
5/11/06

Application # 6542		# of Poles: 21	Proposed Attachment: .625 Coax / .875 Coax
City/Township: Maryland Heights		STATE MO	Attaching Client Company: Cable America

Client Map Number		Pole Owner	Pole Owner #	Pole Structure	Overlash	Existing Attachment Height	Proposed Attachment Height	Lowest Power	Midspan	Neutral Midspan	Extreme %	Heavy % Loaded/Capacity	Guy Req'd (Y/N) Power or other	Guy Lead & Position	Violation or Clearance Issue	Make Ready Recommendations Power	Make Ready Recommendations CATV
K6	1	AUE	154861	3PH TANGENT; POLE TO POLE	OL	25ft 06in	24ft 06in	26ft 02in	22ft 01in	26ft 07in		51.2%	N		YES		LOWER CATV TO 24' 06" & RE-SAG. LOWER OTHER CATV FROM 24' 06" TO 23' 06" & RE-SAG.
K6	2	AUE	154860	3PH DOUBLE DEADEND TANGENT; UNGUYED	OL	21ft 01in	21ft 01in	25ft 11in	18ft 00in	23ft 07in		48.2%	N		NO		N/A
K6	3	AUE	154859	3PH ANGLE; GUYED	OL	19ft 07in	19ft 01in	20ft 09in	18ft 04in	23ft 11in		57,1%	N		YES		LOWER CATV TO 19' 01" & RE-SAG. LOWER OTHER CATV FROM 18' 05" TO 18' 01" & RE-SAG.
K6	4	AUE	154858	3PH TANGENT; UNGUYED	OL	18ft 01in	18ft 01in	22ft 03in	17ft 00in	22ft 00in		16.0%	N		NO		N/A
K6	5	AUE	154856	3PH TANGENT; 3PH DEADEND ANGLE; UNGUYED	OL	19ft 06in	18ft 02in	22ft 06in	15ft 06in	21ft 10in		67.0%	N		YES		LOWER CATV TO 18' 02" & RE-SAG. LOWER OTHER CATV FROM 19' 06" TO 19' 02" AND FROM 17' 06" TO 17' 02" & RE-SAG.
K6	6	AUE	154855	3PH TANGENT; UNGUYED	OL	19ft 01in	17ft 09in	20ft 09in	N/A	24ft 10in		30.6%	N		YES		OVERLASH TO EXISTING STRAND AT 19' 01", LOWER TO 17' 09" & SAG. LOWER OTHER CATV FROM 18' 01" TO 16' 09" & RE-SAG.
K6	7	AUE	154852	3PH TANGENT; UNGUYED	OL	24ft 07in	24ft 07in	28ft 00in	N/A	28ft 02in		55.0%	N		NO		OVERLASH TO EXISTING STRAND AT 24' 07" & SAG
K6	8	AUE	154853	SECONDARY POWER POLE; GUYED		N/A	23ft 02in	26ft 06in	N/A	22ft 11in		45.0%	N		YES		ATTACH CATV AT 23' 02" & SAG. LOWER OTHER CATV FROM 22' 06" TO 22' 02" & RE-SAG. LOWER PHONE FROM 22' 06" 21' 02" & RE-SAG.
J8	9	AUE	2336118	SECONDARY POWER POLE; GUYED		N/A	19ft 07in	26ft 09in	N/A	N/A		28.2%	Y	11' @ 0°	YES		PROPOSE 6M COMM GUY AT 19' 07" WITH 11' LEAD AT 0°. ATTACH CATV AT 19' 07" & SAG.
K6	10	AUE	154851	3PH TANGENT; 1PH DEADEND ANGLE; UNGUYED	OL	21ft 08in	21ft 08in	24ft 03in	N/A	25ft 03in		65.9%	N		NO		OVERLASH TO EXISTING STRAND AT 21' 08" & SAG
K6	11	AUE	154849	3PH TANGENT; UNGUYED	OL	18ft 04in	18ft 04in	21ft 06in	N/A	25ft 06in		46.7%	N		YES		OVERLASH TO EXISTING STRAND AT 18' 04" IN BACKSPAN & SAG. LOWER EXISTING CATV FROM 18' 00" TO 17' 04" & RE-SAG.
K6	12	AUE	154850	1PH DEADEND TANGENT; UNGUYED		N/A	22ft 04in	25ft 04in	N/A	N/A		41.5%	N		NO		ATTACH CATV AT 22' 04" & SAG

ATTACHMENT 5

Utilimap Corporation
1053 Headquarters Park
Fenton, MO 63026
Ph: 636-533-4016
Fax: 636-533-4056

Total New Builds 12

The recommendations on this "make-ready" document are based on field measurements and pole load analysis calculations. They are not intended to be detailed engineering instructions for construction. The attaching party is responsible for verifying actual field conditions and developing details for construction prior to attachment in accordance with the NESC, local ordinances and the appropriate utility requirements.

Engineer Seal

STATE OF MISSOURI
KENNETH W. ROBB
NUMBER PE-2001029646
PROFESSIONAL ENGINEER
Kenneth W. Robb
5/11/06

Application # 6542 | # of Poles: 21 | Proposed Attachment: .625 Coax / .875 Coax

City/Township: Maryland Heights | STATE MO | Attaching Client Company: Cable America

Client Map Number		Pole Owner	Pole Owner #	Pole Structure	Overlash	Existing Attachment Height	Proposed Attachment Height	Lowest Power	Midspan	Neutral Midspan	Extreme %	Heavy % LoadedCapacity	Guy Req'd (Y/N) Power or other	Guy Lead & Position	Violation or Clearance Issue	Make Ready Recommendations Power	Make Ready Recommendations CATV
J6	13	AUE	2336119	SECONDARY POWER POLE; GUYED	[redacted]	N/A	21ft 03in	24ft 07in	N/A	N/A		22.7%	Y	5' @ 0°	YES		PROPOSE 6M COMM GUY AT 21' 03" WITH 5' LEAD AT 0°. ATTACH CATV AT 21' 03" & SAG. LOWER EXISTING CATV FROM 21' 03" TO 20' 03" & RE-SAG.
K6	14	AUE	154848	3PH TANGENT; 3PH DEADEND ANGLE; GUYED	[redacted]	N/A	22ft 11in	26ft 03in	N/A	26ft 11in		21.4%	Y	10' @ 55°	YES		PROPOSE 6M COMM GUY AT 21' 11" WITH 10' LEAD AT 55°. ATTACH CATV AT 22' 11" & SAG. LOWER EXISTING CATV FROM 22' 11" TO 21' 11' & RE-SAG.
K6	15	AUE	154835	3PH DOUBLE DEADEND ANGLE; UNGUYED	[redacted]	N/A	24ft 09in	30ft 05in	N/A	25ft 11in		52.2%	N		NO		ATTACH CATV AT 24' 09" & SAG
J6	16	AUE	154837	3PH DOUBLE DEADEND ANGLE; GUYED	[redacted]	N/A	20ft 02in	23ft 06in	N/A	22ft 02in		8.7%	Y	10' @ 280°	YES		PROPOSE 3/8" HS COMM GUY AT 20' 02" WITH 10' LEAD AT 280°. ATTACH CATV AT 20' 02" & SAG. LOWER EXISTING CATV FROM 20' 10" TO 19' 02" & RE-SAG. LOWER PHONE FROM 19' 02" TO 18' 02" & RE-SAG.
J6	17	AUE	154838	3PH TANGENT; UNGUYED	[redacted]	N/A	18ft 09in	21ft 03in	N/A	22ft 08in		50.4%	N		YES		ATTACH CATV AT 18' 09" & SAG. RE-SAG PHONE FRO MIDSPAN CLEARANCE.
J6	18	AUE	154840	3PH TANGENT; POLE TO POLE	[redacted]	N/A	19ft 08in	23ft 00in	N/A	26ft 06in		74.2%	N		YES		ATTACH CATV AT 19' 08" & SAG. LOWER EXISTING CATV FROM 19' 08" TO 18' 08" AND FROM 21' 09" TO 18' 08" & RE-SAG. LOWER PHONE FROM 21' 09" TO 17' 08" & RE-SAG.
J6	19	AUE	154842	3PH TANGENT; POLE TO POLE	[redacted]	N/A	20ft 04in	26ft 07in	N/A	25ft 00in		75.4%	N		NO		ATTACH CATV AT 20' 04" & SAG
J6	20	AUE	154843	3PH TANGENT; 1PH DEADEND ANGLE; GUYED	[redacted]	N/A	20ft 06in	27ft 03in	N/A	22ft 01in		14.1%	Y	10' @ 50°	YES		PROPOSE 3/8" HS COMM GUY AT 20' 06" WITH 10' LEAD AT 50°. ATTACH CATV AT 20' 06" & SAG.
J6	21	AUE	2336121	1PH TANGENT; UNGUYED	[redacted]	N/A	17ft 08in	21ft 00in	N/A	21ft 03in		43.2%	Y	10' @ 0°	YES		PROPOSE 6M COMM GUY AT 17' 08" WITH 10' LEAD AT 0°. ATTACH CATV AT 17' 08" & SAG. LOWER EXISTING CATV FROM 17' 04" TO 16' 08" & RE-SAG. LOWER PHONE FROM 18' 00" TO 15' 08" & RE-SAG.

Osmose O-Calc ™ Pole Loading Analysis Report

Licensed To: Utilimap

Group ID:	K6_6542	Pole Length / Class:	45 / 3	Code:	NESC Standard	Extreme Wind:	No
Pole ID:	15_154835	Pole Species:	SOUTHERN PINE	Construction Grade:	C	Extreme Wind Speed (mph):	
Related To:	PARENT	Groundline Fiber Stress (psi):	8,000	Loading District:	Heavy	Strength Factor:	0.85
OWNER:	AUE 154835	Fiber Stress Height Reduction:	No	Ice Radial Thickness (in):	0.50	Transverse Wind OLF:	1.75
JOB #:	6542	Structure Type:	ANGLE	Wind Speed Applied (mph):	39.53	Transverse Wire Tension OLF:	1.30
CLIENT:	CABLE AMERICA	Setting Depth (ft):	7.25	Wind Pressure (psf):	4.00	Longitudinal Wire Tension OLF:	1.00
EMPL. #:	133	Allowable Moment at 0.0 ft:	91,143	Wind Angle (deg):	-103.25	Vertical Load OLF:	1.90

Maximum Capacity Utilization:	52.7%	with wind at -103.2°	at 0.0 ft
Groundline Capacity Utilization:	52.7%	with wind at -103.2°	at 0.0 ft
Vertical Buckling Capacity Utilization:	11.9%	with wind at -103.2°	at 23.3 ft

Wind at -103.2° **Moment 47,620 lb-ft at -109.5°**

GROUNDLINE LOAD SUMMARY:** | **0.50" Ice + 39.53 mph Wind at -103.2°** | **Applied Moment 47,620 lb-ft at -109.5°** | **Allowable Moment 91,143 lb-ft**

	Shear Load (lb)**	Percent Applied Load	Bending Moment (lb-ft)	Percent of Applied Moment*	Percent of Pole Capacity	Bending Stress (psi)	Vertical Load (lb)	Vertical Stress (psi)	Total Stress (psi)	Percent of Pole Capacity
Power Conductors:	685	41.6	24,473	51.4	26.9	1,826	-417	-4	-1,830	26.9
Comm. Cables:	734	44.6	18,113	38.0	19.9	1,351	-384	-4	-1,355	19.9
Pole:	209	12.7	3,640	7.6	4.0	272	-2,182	-20	-292	4.3
Crossarms:	7	0.4	268	0.6	0.3	20	-190	-2	-22	0.3
Insulators:	6	0.4	220	0.5	0.2	16	-139	-1	-18	0.3
Transformers:	0	0.0	0	0.0	0.0	0	0	0	0	0.0
Equipment:	4	0.2	905	1.9	1.0	68	-171	-2	-69	1.0
Guy Wire Loads:	0	0.0	0	0.0	0.0	0	0	0	0	0.0
Guy Wire Reactions:	0	0.0	0	0.0	0.0	0	0	0	0	0.0
Pole Residual Load:	1,645	100.0	47,620	100.0	52.2	3,553	-3,482	-32	-3,585	52.7
Pole Reserve Capacity:			43,523		47.8	3,247			3,215	47.3

Vertical Load Summary:

Buckling Constant:	2.00
Buckling Column Height (ft):	23.31
Buckling Section Height (% Col. Hgt.):	33.51
Buckling Section Diameter (in):	10.86
Min. Buckling Diameter at GL (in):	7.30
Diameter at Tip (in):	7.32
Diameter at GL (in):	11.79
Modulus of Elasticity (psi):	1,600,000
Buckling Load Capacity at Height (lb):	29,319
Buckling Load Applied at Height (lb):	3,482
Buckling Load Margin of Safety:	7.42

Power Conductors:	Phase	Attach Height (ft)	Left Sag (ft)	Right Sag (ft)	Horiz. Offset (in)	Cable Dia. (in)	Cable Weight (lb/ft)	Left Span (ft)	Left Angle (deg)	Left Tension (lb)	Right Span (ft)	Right Angle (deg)	Right Tension (lb)	Tension Moment (lb-ft)**	Offset Moment (lb-ft)**	Wind Moment (lb-ft)**	Moment at GL (lb-ft)**
ACSR 1/0 AWG 6/1 RAVEN		36.75	4.65	-	13.92	0.398	0.145	105.0	0.0	209	-	-	-	3,334	27	1,444	4,805
ACSR 1/0 AWG 6/1 RAVEN		36.75	-	0.74	13.60	0.398	0.145	-	-	-	36.0	-25.0	155	709	-4	526	1,230
ACSR 1/0 AWG 6/1 RAVEN		36.25	4.65	-	46.28	0.398	0.145	105.0	0.0	209	-	-	-	3,288	-194	1,424	4,519
ACSR 1/0 AWG 6/1 RAVEN		36.25	4.65	-	46.28	0.398	0.145	105.0	0.0	209	-	-	-	3,288	270	1,424	4,982
ACSR 1/0 AWG 6/1 RAVEN		36.25	-	0.74	48.27	0.398	0.145	-	-	-	36.0	-25.0	155	699	71	519	1,289
ACSR 1/0 AWG 6/1 RAVEN		36.25	-	0.74	43.88	0.398	0.145	-	-	-	36.0	-25.0	155	699	-88	519	1,131
ACSR 1/0 AWG 6/1 RAVEN		32.83	4.65	0.55	13.78	0.398	0.145	105.0	0.0	209	36.0	-25.0	209	3,833	102	1,759	5,694
DUPLEX 1/0		32.83	-	6.55	14.05	0.954	0.260	-	-	-	36.0	-25.0	30	123	44	656	823
Totals: 8 Wires														**15,973**	**228**	**8,271**	**24,473**

Communication Cables:	Owner	Attach Height (ft)	Left Sag (ft)	Right Sag (ft)	Horiz. Offset (in)	Cable Dia. (in)	Cable Weight (lb/ft)	Left Span (ft)	Left Angle (deg)	Left Tension (lb)	Right Span (ft)	Right Angle (deg)	Right Tension (lb)	Tension Moment (lb-ft)**	Offset Moment (lb-ft)**	Wind Moment (lb-ft)**	Moment at GL (lb-ft)**
PRO 625/PRO 875		24.75	3.28	0.39	5.24	1.63	0.513	105.0	0.0	772	36.0	-25.0	772	10,672	101	2,495	13,269
CATV 500 + 1/4 MESSENGER		23.75	6.01	0.70	4.89	0.81	0.214	105.0	0.0	237	36.0	-25.0	237	3,144	53	1,648	4,845
Totals: 2 Wires														**13,816**	**154**	**4,143**	**18,114**

Attachment 6

* not including Guy Wire Tension ** includes Overload Factor(s)

Osmose O-Calc ™ Pole Loading Analysis Report

Licensed To: Utilimap

Group ID:	K6_6542	Pole Length / Class:	45 / 3	Code:	NESC Standard	Extreme Wind:	No
Pole ID:	15_154835	Pole Species:	SOUTHERN PINE	Construction Grade:	C	Extreme Wind Speed (mph):	
Related To:	PARENT	Groundline Fiber Stress (psi):	8,000	Loading District:	Heavy	Strength Factor:	0.85
OWNER:	AUE 154835	Fiber Stress Height Reduction:	No	Ice Radial Thickness (in):	0.50	Transverse Wind OLF:	1.75
JOB #:	6542	Structure Type:	ANGLE	Wind Speed Applied (mph):	39.53	Transverse Wire Tension OLF:	1.30
CLIENT:	CABLE AMERICA	Setting Depth (ft):	7.25	Wind Pressure (psf):	4.00	Longitudinal Wire Tension OLF:	1.00
EMPL. #:	133	Allowable Moment at 0.0 ft:	91,143	Wind Angle (deg):	-103.25	Vertical Load OLF:	1.90

Crossarms:	Owner	Attach Height (ft)	Horiz. Offset (in)	Gap to Pole (in)	Offset Angle (deg)	Rotate Angle (deg)	Incline Angle (deg)	Unit Weight (lb)	Unit Height (in)	Unit Width (in)	Unit Diameter (in)	Unit Length (in)	Shape Factor	Offset Moment (lb-ft)**	Wind Moment (lb-ft)**	Moment at GL (lb-ft)**
1) CROSSARM 3-1/2 X 4-1/2 X 8		36.25	6.50	1.00	180.0	180.0	0.0	50.0	4.50	3.50	-	96.00	1.6	17	134	151
2) CROSSARM 3-1/2 X 4-1/2 X 8		36.25	6.50	1.00	0.0	0.0	0.0	50.0	4.50	3.50	-	96.00	1.6	-17	134	117
Totals: 2Crossarms								**100.0**						**0**	**268**	**268**

Insulators:	Owner	Attach Height (ft)	Horiz. Offset (in)	Gap to Pole (in)	Offset Angle (deg)	Rotate Angle (deg)	Incline Angle (deg)	Unit Weight (lb)	Unit Height (in)	Unit Diameter (in)	Shape Factor	Offset Moment (lb-ft)**	Wind Moment (lb-ft)**	Moment at GL (lb-ft)**
Dead End Insulator, 6"		36.75	8.22	3.00	180.0	-90.0	90.0	10.5	11.00	3.00	1.0	5	26	30
Dead End Insulator, 6"		36.75	8.22	3.00	0.0	65.0	90.0	10.5	11.00	3.00	1.0	-5	24	20
Dead End Insulator, 6"		36.25	44.19	38.94	108.1	270.0	90.0	10.5	11.00	3.00	1.0	-58	25	-33
Dead End Insulator, 6"		36.25	44.19	38.94	-108.1	270.0	90.0	10.5	11.00	3.00	1.0	73	25	99
Dead End Insulator, 6"		36.25	44.19	38.94	-71.9	65.0	90.0	10.5	11.00	3.00	1.0	58	24	82
Dead End Insulator, 6"		36.25	44.19	38.94	71.9	65.0	90.0	10.5	11.00	3.00	1.0	-73	24	-50
Post Insulator		32.83	8.83	3.00	-90.0	0.0	90.0	10.0	9.50	3.75	1.0	13	59	72
Totals: 7 Insulators								**73.0**				**13**	**207**	**220**

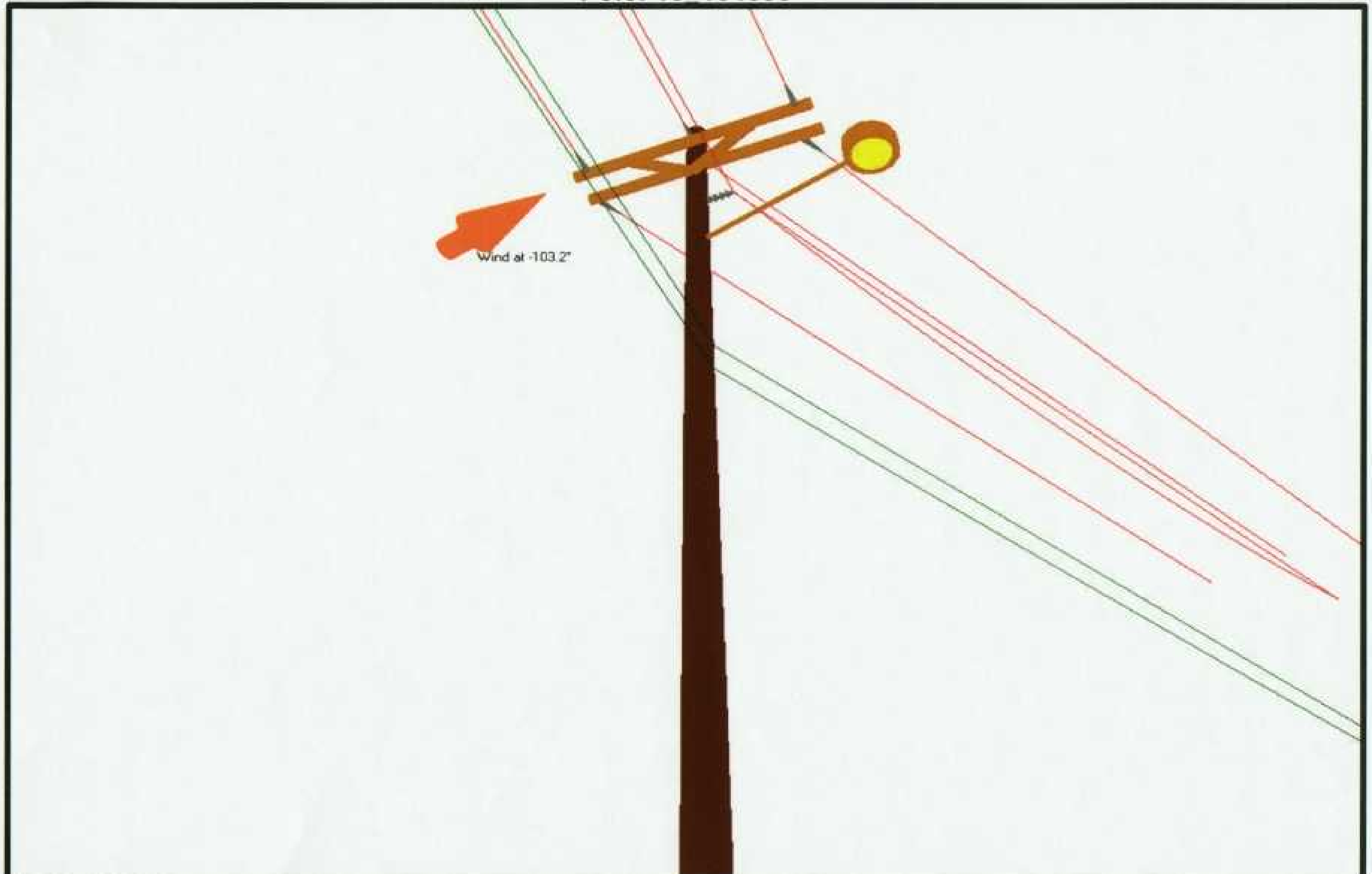
Equipment:	Owner	Attach Height (ft)	Horiz. Offset (in)	Gap to Pole (in)	Offset Angle (deg)	Rotate Angle (deg)	Incline Angle (deg)	Unit Weight (lb)	Unit Height (in)	Unit Width (in)	Unit Diameter (in)	Unit Length (in)	Shape Factor	Offset Moment (lb-ft)**	Wind Moment (lb-ft)**	Moment at GL (lb-ft)**
LIGHT SUPPORT		30.42	36.00	29.91	-105.0	165.0	0.0	40.0	-	-	4.00	72.00	1.0	227	17	245
LIGHT BULB		30.42	72.00	63.41	-105.0	0.0	0.0	50.0	-	-	9.00	6.00	1.0	568	92	661
Totals: 2Equipment								**90.0**						**796**	**110**	**905**

Pole Notes:

38° 42.218
-90° 27.736

* not including Guy Wire Tension ** includes Overload Factor(s)

Group: K6_6542
Pole: 15_154835



Wed, May 10, 2006 04:21 pm

O-Calc™ Version: 3.4


15-4835
15

Appendix D

Draft Vegetation Management Reporting Rule

Title 4 – DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240 – Public Service commission
Chapter 3 – Filing and Reporting Requirements

PROPOSED RULE

4 CSR 240-3.191 Electric Utility Vegetation Management Reporting and Plan Submission Requirements

(1) *Annual submission of performance report.* Commencing on January 1, 200X, each electric utility shall accumulate the following information for each calendar year and annually transmit it to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of February in the following calendar year.

(A) *Contents of report.* A summary report detailing all activities conducted during the calendar year related to vegetation management.

1. The report shall segregate the activities based on circuit voltage groupings. These groupings shall be used to differentiate between transmission and distribution.
2. The report shall include circuit-miles affected by vegetation management activities during the calendar year for each grouping. [The circuit-miles reported should be expressed as the physical length of the affected circuits within the grouping and also as a percentage of the total length of circuits for that grouping.]
3. The report shall include expenses incurred and techniques utilized (e.g., chemical, mechanical, or other methods) for overall vegetation management activities.
4. The information for section 1.(A).1,1(A),2, and 1(A).5 shall be reported for the entire electric utility system (Missouri jurisdiction) and also reported by regional/district/division operating areas, if the utility is divided into regions/districts/divisions.

5. The report shall provide detailed information regarding the extent of vegetation management and tree removals on both the utility system right-of-way and off the utility system right-of-way (adjacent to the utility system right-of-way).

(B) A summary report detailing the electric utility's criteria for assessing the effectiveness of the vegetation management plan and the results of those assessments.

(C) The summary report required by Section (1)(A) shall include a comparison of vegetation management activities scheduled for the calendar year and the actual vegetation management activities completed.

(D) A summary report detailing total customer outages during the calendar year that are attributable to vegetation interference, excluding major storm events. The information shall be reported for the entire electric utility system (Missouri jurisdiction) and also reported by regional/district/division operating areas, if the utility is divided into regions/districts/divisions.

(2) *Annual submission of plan*. Commencing on January 1, 200X, each electric utility shall prepare the following information for each calendar year and annually transmit it to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of December in the preceding calendar year.

(A) *Contents of plan.* A summary report detailing all scheduled vegetation management activities for the following calendar year including affected circuit-miles, budgeted expenses, and methods to be utilized for vegetation management. The report information shall be limited to distribution facilities. The information shall be reported for the entire electric utility system (Missouri jurisdiction) and also reported by regional/district/division operating areas, if the utility is divided into regions/districts/divisions. Transmission system information shall be reported by each utility submitting a copy of FERC report FAC-003-1.

(3) *Field inspections.* All electric utilities shall participate in joint field inspections of vegetation management activities, as requested by the staff of the commission. These field inspections may include vegetation management activities in progress and locations of completed vegetation management activities.

Appendix E

Draft Infrastructure Inspection Reporting Rule

Title 4 – DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240 – Public Service Commission
Chapter 3 – Filing and Reporting Requirements

PROPOSED RULE

4 CSR 240-3.192 Electric Utility Infrastructure Inspection and Maintenance Plan Submission Requirements

(1) *Submission of plan.* Each electric utility shall adopt and annually transmit to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of February a written program for inspecting and maintaining its electric supply lines and substations (excluding generating stations), for the current year, in order to determine the necessity for replacement, maintenance and repair. If the plan is amended or altered, revised copies of the appropriate plan pages shall be submitted.

(2) *Annual report.* Each utility shall include as part of its annual report to the commission staff an analysis and certification of compliance with each area of the inspection plan for the previous year's plan or a detailed statement on areas of noncompliance to the previous year's plan

(3) *Contents of plan.* The inspection plan shall include the following elements:

(A) *General.* A listing of all counties or parts of counties in which the utility has electric supply lines in Missouri. If the utility has district or regional offices responsible for implementation of a portion of the plan, the addresses of those offices and a description of the territory for which they are responsible shall also be included.

(B) *Inspection of lines, poles, and substations.*

1. Inspection schedules. The plan shall contain a schedule for the periodic inspection of the various units of the utility's electric plant. The period between inspections shall be based on accepted good practice in the industry, but shall not exceed twelve years for any given line or piece of equipment.

2. Inspection coverage. The plan shall provide for the inspection of all supply line and substation units, of primary voltage, within the adopted inspection periods and shall include a complete listing of all categories of items to be checked during an inspection.

3. Instructions to inspectors. Copies of instructions or guide materials used by utility inspectors in determining whether a facility is in acceptable condition or in need of corrective action or further investigation.

(4) *Records.* Each utility shall keep sufficient records to demonstrate compliance with its inspection programs. For each inspection unit, the records of line, pole, and substation inspections shall include the inspection date(s), the findings of the inspection, and the disposition or scheduling of repairs or maintenance found necessary during the inspection. The record shall be kept until two years after the next periodic inspection is completed or until all necessary repairs or maintenance are completed, whichever is longer.

(5) *Conduct of inspections*. Inspections shall be conducted in a manner conducive to the identification of safety, maintenance, and reliability concerns or needs.

(6) *Correction of problems found during inspections.* Corrective action shall be taken within a reasonable period of time on all potentially hazardous conditions, instances of safety code noncompliance, maintenance needs, potential threats to safety and reliability, or other concerns identified during inspections. Hazardous conditions shall be corrected promptly.

Appendix F

Draft Reliability Reporting Rule

Title 4 – DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240 – Public Service commission
Chapter 3 – Filing and Reporting Requirements

PROPOSED RULE

4 CSR 240-3.193 Electric Utility System Reliability Monitoring and Reporting Submission Requirements

(1) *Annual submission of report.* Commencing on January 1, 200X, each electric utility shall accumulate the following information (on a monthly basis) for each calendar year and annually transmit it to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of April in the following calendar year.

(A) *Contents of report.* System Average Interruption Frequency Index (SAIFI) which reflects the average frequency of service interruptions in number of occurrences per customer and is defined as the total number of customer interruptions for the period covered divided by the total number of customers served.

(B) Customer Average Interruption Frequency Index (CAIFI) which reflects the average number of interruptions per customer interrupted and is defined as the total number of customer interruptions for the period covered divided by the total number of customers affected.

(C) System Average Interruption Duration Index (SAIDI) which reflects the average interruption in hours or minutes per customer served for the period covered and is defined as the sum of all customer interruption durations divided by the total number of customers served.

(D) Customer Average Interruption Duration Index (CAIDI) which reflects the average interruption duration and is defined as the sum of all customer interruption durations divided by the total number of customers interrupted.

(2) The information required by Section (1) shall be submitted electronically in tabular and graphical formats.

(3) The information required by Section (1) shall be submitted unadjusted and adjusted to exclude major storm events per IEEE Standard 1366, IEEE Guide for Electric Power Distribution Reliability Indices.

(4) The information required by Section (1) shall be reported for the entire electric utility system (Missouri jurisdiction).

(5) *Interruptions not to be reported.* The following interruption causes shall not be included in the calculation of the reliability indices required by Section (1):

(A) Interruptions initiated pursuant to the provisions of an interruptible service tariff or contract and affecting only those customers taking electric service under such tariff or contract;

(B) Interruptions due to nonpayment of a bill;

(C) Interruptions due to tampering with service equipment;

(D) Interruptions due to denied access to service equipment located on the affected customer's private property;

(E) Interruptions due to hazardous conditions located on the affected customer's private property;

(F) Interruptions due to a request by the affected customer;

(G) Interruptions due to a request by a law enforcement agency, fire department, other governmental agency responsible for public welfare, or any agency or authority responsible for bulk power system security or reliability; or

(H) Interruptions caused by the failure of a customer's equipment; the operation of a customer's equipment in a manner inconsistent with law, an approved tariff, rule, regulation, or an agreement between the customer and the electric utility; or the failure of a customer to take a required action that would have avoided the interruption, such as failing to notify the company of an increase in load when required to do so by a tariff or contract.

(6) *Worst performing circuits.* Each electric utility shall establish and maintain a program for identifying and analyzing its worst performing circuits during the course of each calendar year. The program shall include, but should not be limited to, an analysis of the top 5% worst performing circuits for the entire electric utility system (Missouri jurisdiction). The worst performing circuits shall be identified and ranked using SAIFI values computed for each circuit, adjusted to exclude major storm events per IEEE Standard 1366, IEEE Guide for Electric Power Distribution Reliability Indices and in any other manner chosen by the utility. The SAIDI value for each circuit shall also be listed.

(7) The information developed in accordance with Section (6) shall be reported for each calendar year to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of April in the following calendar year. This report shall also include actions taken (or planned) to improve the performance of the circuits identified in Section (6).

(8) *Multi-year worst performing circuit reporting*. For subsequent years, following calendar year 200X, the performance of the circuits reported in accordance with Section (7) for the three (3) previous calendar years (as developed) will be reported to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of April in the following calendar year. If a circuit is on the worst performing circuit list, submitted in accordance with Section (7), for three (3) consecutive calendar years; the electric utility shall include detailed plans and schedules for improving the performance of that circuit in the annual report required by Section (7). Such plans and schedules may vary from circuit to circuit based on differences in geography or other local conditions, customer density and cost considerations.

(9) *Reliability improvement programs.* Commencing on January 1, 200X, each electric utility shall prepare the following information for each calendar year and annually transmit it to the manager of the Energy Department of the commission, or his/her designee, no later than the last business day of December in the preceding calendar year.

(A) *Contents of plan*. A summary report detailing all programs scheduled for the following calendar year designed to maintain or improve service reliability. The information shall be reported by regional/district/division operating areas, if the utility is divided into regions/districts/divisions. This report shall include funding levels and the status of each of these programs.

Appendix G

Pictures

(Courtesy: Ameren)

(Courtesy: Ameren)

(Courtesy: Ameren)

(Courtesy: Channel 4, St. Louis)

Part of Lambert Terminal Roof on I-70
(Courtesy: Channel 4, St. Louis)


Switzer Bldg. in Laclede's Landing
(Courtesy: Ameren)

(Courtesy: Ameren)

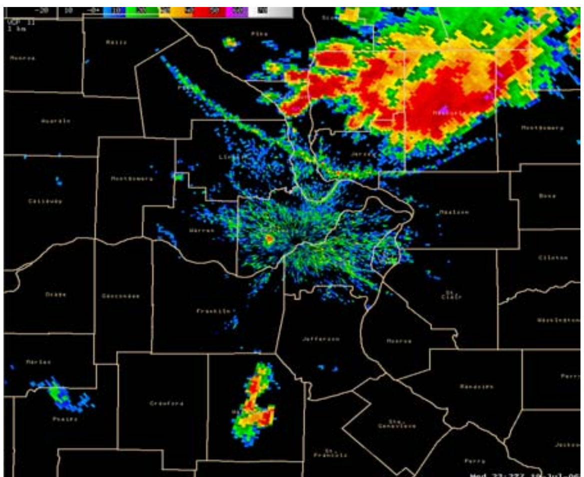

(Courtesy: Ameren)


Tipped Rail Cars on Bridge
(Courtesy: Ameren)

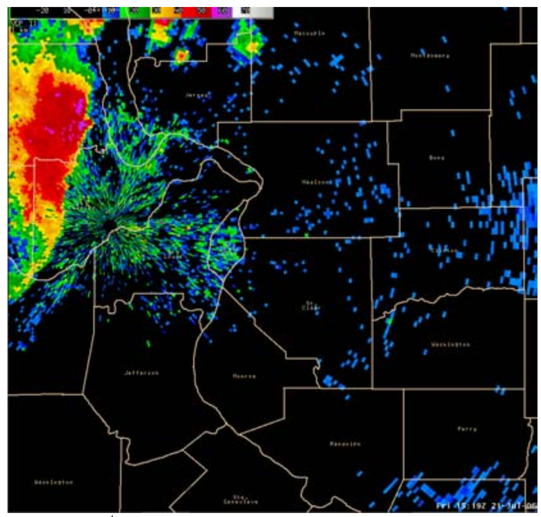

(Courtesy: National Weather Service)

(Courtesy: National Weather Service)

(Courtesy: Mr. Daniel Schesch)



July 19th Storm Approaching St. Louis
(Courtesy: National Weather Service)



July 21st Storm Approaching St. Louis
(Courtesy: National Weather Service)

(Courtesy: Ameren)

Manufactured Home on Highway
(Courtesy: Channel 4, St. Louis)

APPENDIX H

NEWSPAPER ARTICLES

Unexpected fury

The storm's aftermath | Hundreds of thousands face a steamy day without electricity after a swift-moving storm knocks down buildings, trees and power lines.

Neighbors Hugh Wheeler (left) and Terry Penberthy stand amid damage on Louisville Avenue in St. Louis' Dogtown neighborhood. Jerry Naunheim Jr. | Post-Dispatch

FROM STAFF REPORTS

A powerful summer storm slammed into the St. Louis area Wednesday evening, toppling buildings, street lights, tractor trailers and hundreds of trees.

At least 476,000 customers lost power, Metrolink was shut down and just one-third of flights were getting in and out of Lambert Field.

"This is one of the worst storms we can all remember to hit the city of St. Louis in recent years," St. Louis Mayor Francis Slay said at a hurriedly called news conference.

The power outages will present a challenge to utility crews trying to get the power back on in temperatures expected to exceed 100 degrees today.

Until Wednesday, the two biggest storms to hit the area in the last few years were in July 2004, when about 225,000 lost power, and in August 2005, which affected about 250,000. It took AmerenUE crews four days to restore power to all customers in 2004 and five days in 2005.

The storm brewed quickly in central Illinois and swept southwest toward the St. Louis area shortly after 7 p.m. Meteorologists said the storm was unusual, not because of its path, but because a powerful "gust front" preceded the rain and thunder, causing damage from St. Charles County in the west to Madison County in the east, but hitting St. Louis and St. Louis County hardest.

PLEASE SEE **STORM** | **A2**

Thursday, July 20, 2006
St. Louis Post-Dispatch

Lives and limbs

HISTORIC POWER OUTAGE • NATIONAL GUARD ARRIVES • TWO DEAD

In Arnold on Thursday, Tom Harris waits for the arrival of the American Red Cross after trying to salvage belongings at his home on Fannie Drive. A large white oak tree ripped through his living room Wednesday night while he and his wife, Tana, were watching television weather reports with their family. When the roof collapsed, his son Levi, 5, was trapped and was freed when family members lifted the roof trusses. Robert Cohen | Post-Dispatch

A state of emergency

Residents on both sides of the Mississippi River began on Thursday the long, tedious job of piecing together their communities, starting just hours after a devastating storm caused widespread damage. Two deaths and 30 injuries were blamed on the storm. Missouri's National Guard was scheduled to begin assisting cleanup efforts. AmerenUE customers without power could only wait; it might take a few days before their power is restored.

FULL STORM COVERAGE

PAGES A10-12 • METRO • BUSINESS • SPORTS

Friday, July 21, 2006
St. Louis Post-Dispatch

THE KANSAS CITY STAR.

Saturday, July 22, 2006

WWW.KANSASCITY.COM

Outages the worst ever in St. Louis

New storms have undone efforts to restore electricity as residents seek refuge.

By JEFF DOUGLAS
The Associated Press

ST. LOUIS | A fresh round of storms brought new power outages to St. Louis on Friday as about 570,000 homes and businesses braced for a weekend without electricity.

Crews worked feverishly to restore power after storms toppled trees and tore the roofs off homes Wednesday, but a second wave of storms Friday erased utility workers' progress.

Ameren Corp. officials said it could be early next week before all power is restored. Ameren called the outage the worst in the city's history.

"It definitely represents some more challenges for us. The storm that blew through here left a lot of damage," Ameren spokesman Tim Fox said. "It essentially has affected power for another 200,000 customers."

Three people have died as result of the storms and heat.

The heat subsided Friday-with highs in the 70s and low 80s, and highs in the 70s were forecast for the weekend.

Residents turned their attention to the mess left by the storms and the loss of power.

HUY RICHARD MACH | THE ASSOCIATED PRESS

Members of the Missouri National Guard removed a fallen limb off Kingshighway on Friday as they helped check on residents in the neighborhoods of north St. Louis. Missouri Gov. Matt Blunt mobilized the troops to help the area recover from Wednesday's storms.

In northwest St. Louis County, winds from the latest storm tore the roof off an office building, causing concerns about a natural-gas leak and displacing about 100 workers.

"I saw the roof flying, and I was thinking, 'Please, don't hit my car,'" said Jeff Winkler, 26, an analytical chemist at Severn Trent Labs, who was pulling into the parking lot. "I thought I saw the worst of it earlier this week — but this was worse."

More than 500 people spent Thursday night in two Red Cross shelters. A third opened Friday afternoon, said Jeff Rainford, chief of staff for Mayor Francis Slay. Besides the overnight centers, municipal officials set up 52 cooling centers in the city and St. Louis County.

"There are a lot of people who are hungry because all of their food has spoiled," said Agnes Reese, 48, who spent Friday at one of the shelters.

Many fast-food restaurants and groceries remained closed and without power. Schnuck Markets Inc., which operates 65 groceries in the St. Louis area, said 26 of its stores lost power. Eight were still without electricity Friday.

Reese relaxed in a tub of cool water Thursday night and had not decided whether to stay in the shelter, where 300 people slept Thursday night even though there were cots for 200.

Among those taking shelter at the community center were about 200 residents of nursing homes, some of them using wheelchairs.

Debra Raymond, 50, hoped to avoid staying overnight at the shelter. She slept Thursday with a dozen relatives and friends on the floor of her daughter's air-conditioned home.

"We came to the shelter to cool off and get some warm food," Raymond said. "We are hoping and praying we'll have electricity tonight."

In De Soto, about 40 miles south of St. Louis, the death of a 93-year-old man appeared to be heat-related, Jefferson County Sheriff's Capt. Ralph Brown said. The man and his 82-year-old wife had refused to leave their home despite Thursday's heat and power outage. Brown said the temperature inside the home was 85 degrees.

Virtually every hotel room in the region was booked for the weekend, mostly by residents fleeing homes without power.

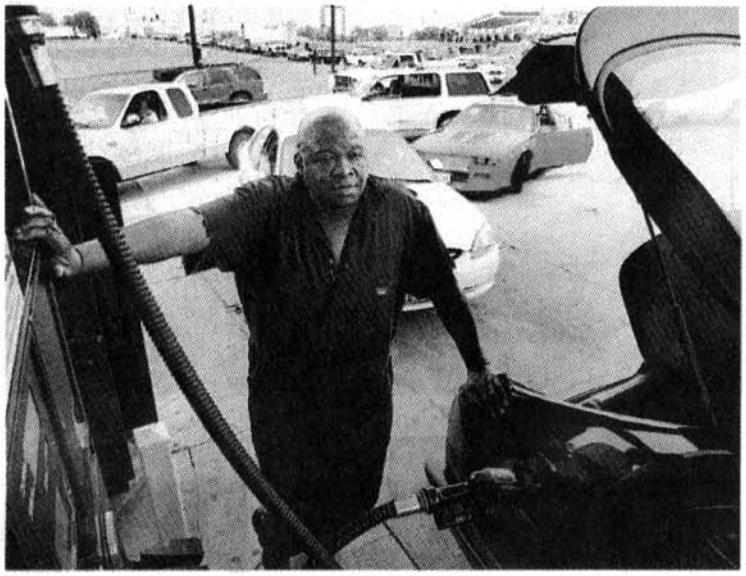
Gov. Matt Blunt on Thursday declared a state of emergency in the city. The state has asked President Bush for federal disaster assistance.

Jim Salter of The Associated Press contributed to this report.

Gauging economic impact of storms can be guesswork

Early reports of costs should be viewed with skepticism, experts say.

By Repps Hudson
ST. LOUIS POST-DISPATCH



Charley Williams fills his tank Friday at a QuickTrip in north St. Louis County. The station operated on a generator. Many stations that lost power were closed. Jerry Naunheim Jr. | Post-Dispatch

Measuring the economic impact of a natural disaster such as the storms that struck the St. Louis area Wednesday and Friday is at best guesswork by careful analysts — and even those numbers won't be available for weeks or even months.

So economists and government leaders advise skepticism over economic loss estimates likely to arise over the next few days.

The best estimates are derived from a careful analysis of affected neighborhoods, the level of income of residents in those neighborhoods and the loss of business when restaurants and stores are forced to close because they have no electricity, said Don Phares, professor emeritus of economic and public policy at the University of Missouri at St. Louis.

"It would be an educated guess, with some qualifications," Phares said.

He cautioned that until all electrical power is restored and the emergency for residents and businesses is ended, there is no way to plausibly gauge economic losses.

Still, such a calamity is a net loss to the economy, said Glenn MacDonald, associate dean of Washington University's Olin School of Business. It's not even offset by the many people working overtime to put things back in order and by stores selling generators, plywood, batteries and other necessities.

"We look at all the work some people do, but then look at the capital losses," he said. "This is bad, on net. If it were good (for the local economy), we'd want to create more storms."

MacDonald noted that there are two things to consider when studying the economic impact of a disaster such as the storms. "What kind of economic activity has been delayed? If I was going to wash my car and the storm hit, I'll probably still go wash my car in a few days," he said. "What kind of economic activity has been lost forever? If a tree or a car or a house is damaged, broken or gone, that's destroyed capital. The net is bad."

A natural disaster can hit different segments of society very differently, Phares said.

For example, some businesses that have had to close because they have no electricity have employees who are paid minimum wage or slightly more.

"Those people are at the low end of the spectrum," he said. "They are just creeping by. If the place they work is closed three, four or five days or more, that's one less paycheck, and that can put them into a tailspin. If you or I lose a week's paycheck, we can survive. They may not be able to."

Another factor to consider is the business and commercial areas disabled by the storm or the outage. That would lead to losses in sales taxes, which makes up 50 percent to 60 percent of the operating budgets for some cities.

"The sales tax has become a primary source of income for cities," said Stuart Haynes, staff associate of the Missouri Municipal League. "If you're talking about a week (of not collecting sales taxes), boy, that's a lot."

Cities also count on receipts from utility taxes. If a customer's electricity is cut off, then his or her city may not receive as much revenue from that tax, which Haynes said typically makes up about 15 percent of city budgets.

But that seemingly clear picture is muddled by other factors.

For instance, said Willie Norfleet, director of finance of University City, which has been damaged by winds and has residential and business power outages, the loss of utility taxes may differ little from a typical summer.

"We may have cool days in July when people don't use their air conditioning," Norfleet said. "The storm could hurt individual businesses, but not so much the city."

rhudson@post-dispatch.com
314-340-8208

Sunday, July 23, 2006
St. Louis Post-Dispatch

St. Louis Post-Dispatch -- Sunday, July 23, 2006

POWER STILL OUT IN BALLWIN. Huge 60-plus-year-old tree on the deck. It took out the deck/shade cover and a corner of the house. Also took another smaller tree with it. Had the wind come from the west like normal, it would have taken the cars and half the house. Numerous limbs and trees down in the neighboorhood (Kehrs Mill/Skyline area). **Christy**

POWER STILL OUT AT MY HOUSE IN BEVO (at my parents' house now). Watched the storm from my porch as it tore siding parts of the neighbors' houses, snapped many trees and shorted out the power lines. My house was strangely unscathed. Saw a piece of aluminum soffit twisted and woven between wires up in the power lines on the telephone pole (that's going to have to be taken down before the power can come back on, I'm sure). Lots of damage and power out in that part of south city though. Saw a storefront collapsed inward on Morganford near Tower Grove Park. Quite a few overhead traffic signals lying on the ground. Traffic signals at Hampton and Chippewa were partially down as well as flashing green and flashing red both in the same direction. That was a bit amusing. **Mike H**

I WAS ALSO AT THE STADIUM. I have never been so fearful for my life. It was truly terrifying, since there is really no place for shelter for 40,000 people. The crowd was pretty orderly, all things considered. The road in front of the Arch was completely trashed. It was littered with debris from stuff that was alongside the road for the Live On The Levee festival this weekend. Heading east, the first town we came to that had power was O'Fallon, Ill. For once, it was actually a good thing to live so far away from civilization, as the small town that I live in did have power. **TC**

FOURTEEN HOURS LATER, POWER IS STILL OUT on Ridgeview Drive (unincorporated St. Louis County, near Carman & Doughtery Ferry roads). This is completely understandable given the scope and power of (Wednesday) night's storm. What is NOT understandable is that this is the fourth time this year alone that power to this neighborhood has been lost for a signifcant amount of time. That's correct, four times in seven months. In addition, power outages took place here at least four times in 2005. In my 20s, I lived for two years in a Third World country and didn't lose electrical power this often. **Dan Layton**

MY HUSBAND WAS SUPPOSED TO LEAVE ST. LOUIS (Wednesday) night at 6. As he waited, it got very dark. He said that when they were about to board the plane, an announcement was made that boarding would be delayed because of a storm. He sat back down and a fellow passenger asked him to watch her bags as she went to the restroom. While she was gone, they announced that everyone needed to evacuate the terminal. My husband said that the windows started to bend and flex! As soon as the lady returned, they left. He tried calling relatives to find out what was going on and when he got a hold of one cousin she couldn't tell him anything since they had lost power. He finally got to LAX at 11:20 p.m., or 1:20 a.m. your time. We got home at 1:10 our time and he was up at 5 a.m. to go to work. Can we have less drama when we come in September for his high school reunion?
Roberta Fleishman

I WAS AT THE CARDS GAME (Wednesday) night. It was one of the scariest moments of my life. I thought the scoreboard was going to come down at one point. **Scott**

Allyson Heil, 9, of Hamel, stands Sunday amid the rubble of Landmark Pentecostal Church in Bethalto, which was shattered in Wednesday's storm. "I took a few mementos of our church," she said, with tears in her eyes. The congregation worshipped Sunday at First Baptist Church of Bethalto. Gabriel B. Tait | Post-Dispatch

Congregation that lost church counts its blessings

By Jake Wagman
ST. LOUIS POST-DISPATCH
7-24-06

BETHALTO • Every week, Pastor Mark Burk's congregation sings about praise and sacrifice. This week, they had special reason to pray.

While they worshipped as the guests of another church on Sunday, less than a mile away stood the rubble of their former home, the roof ripped off and the sanctuary destroyed by the tempest that tore through the region on Wednesday.

Last week's storms hit Bethalto and parts of the Metro East area like a buzz saw. Gov. Rod Blagojevich declared Clinton, Jefferson, Madison and St. Clair counties disaster areas. As of Sunday, there was still a boil-water order for Caseyville.

Burk's church, the Landmark United Pentecostal Church on Central Avenue, is one of the oldest buildings in Bethalto. The brick and wood structure was built around 1860 and was a place where residents of this town of about 10,00 have gathered for generations.

"So it's seen a lot of storms in its time," Burk said.

Yet none, it appears, had been so fierce as to deposit the church's ceiling beams on the ground below, creating a pile of warped boards and rusting nails.

But the loss for the church could have been more than wood and metal

PLEASE SEE **CHURCH** | A4

had three young adults at Bible study not heeded the tornado warning sirens Wednesday evening. Just moments before the wind whipped through the church, the three went down to the basement. Though the church crumbled, they came through unscathed.

"They heard the sirens. They went down to the basement, and everything collapsed around them," Burk said.

Ryan Harris, 20, was one of the three. He said the group had prayed in the basement, using the glare from their cell phones for light. Harris briefly re-emerged when the storm began, watching it through the crack in the front door.

"I started hearing noises and stuff and thought, 'All right, God, I can take a hint," Harris said.

It's a good thing he did: After he went back to the basement, the church caved in, destroying the pews, the altar and even the baby grand piano.

Burk's pastoral assistant, the Rev. John Heil, was the one who discovered the three who fled to the basement. They have more than that to be thankful for, Heil said — the church was scheduled to have an evening worship later that night.

"If this would have happened 30 minutes later, the church would have been full," Heil said.

On Sunday, Heil's young daughter took a brick from the pile of debris as a memento. Later, Heil met the rest of the congregation at the First Baptist Church of Bethalto, which opened the building to Landmark's members to hold an afternoon service.

Burk said the church's board soon will begin discussions about where to relocate. In the meantime, they were asking for volunteers to haul what could be salvaged from the destroyed building.

"I realize we lost a church, but the church is right here," Burk said. "The church is wherever we gather."

Many people in the area were still without power, making church a welcome respite. The Bethalto Church of God held its service under a tent in the parking lot, where worshippers traded traditional Sunday best for open collars and open-toed shoes.

"I'm a preacher in flip-flops. Good grief," said Pastor Jeremy Robinson.

Storm damage to the church was relatively minor, but it has been without power since Wednesday. Robinson encouraged the congregation to pray for the community, pray for their neighbors and pray — please pray — for the Ameren workers.

jwagman@post-dispatch.com | 314-622-3580

Monday, July 24, 2006
St. Louis Post-Dispatch

INSURANCE CLAIMS

Insurers call storms 'catastrophe'

This tree fell on this home in Troy, Ill., during last week's storms. Claims for property damage from rain, wind, fallen trees and limbs, and lightning throughout the area have been filed with insurance companies. Dawn Majors | Post-Dispatch

State Farm reports 3,900 claims as of Monday, Allstate has 1,344

By Rebecca Roussell
ST. LOUIS POST-DISPATCH

Two large insurers are using the term "catastrophe" to describe the extent of damage from last week's storms, and are providing extra adjusters to handle the demand in claims.

State Farm Insurance Co. reported 3,900 claims as of Monday, said Tia Lindell, spokeswoman for the company. A team of 60 adjusters was sent to the area, in addition to local claims officers reacting to the storm.

State Farm is the No. 1 auto and homeowner insurer in Missouri and Illinois.

Allstate Insurance Co., a top-10 insurer in both states, reported 1,344 claims and sent 42 additional adjusters to the area, said spokeswoman Emily Pukala.

For Allstate, a catastrophe includes events where losses from customers exceed $1 million. State Farm doesn't place a dollar value on the term, but Lindell said it's based on the number of customers affected and the severity of the damage.

The number of homeowner and property claims surpassed auto claims for both companies.

Most of the property damage was from rain, wind, fallen trees and limbs, and lightning, which caused fires.

"This storm [was] really consistent with wind damage," Lindell

PLEASE SEE INSURANCE | C6

MEDICAL CARE

Storms, heat put area hospitals and their staffs to the test

Mary Jo Feldstein
ST. LOUIS POST-DISPATCH

As its neighborhood battled falling trees and widespread power outages, St. Louis University Hospital opened a closed unit to house residents of area nursing homes that are without power. Nurses volunteered for extra shifts. Meanwhile, tired, hungry hospital workers nibbled on granola bars and other snacks wheeled through the floors on a cart.

"We're trying really hard to make it as easy on our staff as possible," said Susan Hakes, a spokeswoman.

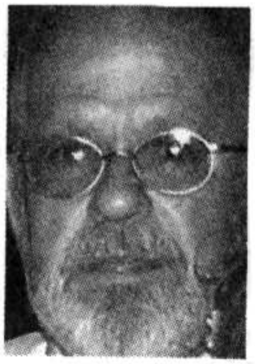
Across the region, hospitals scrambled into action during the storms and throughout the clean-up, but the effort has stressed emergency rooms and staff.

SLU Hospital has used two nurses from an outside staffing agency since the storms hit. That's actually less than it typically would bring in during busy times. The hospital wanted to hire more, but Hakes said they weren't available.

On Monday, airmen from Scott Air Force Base helped SLU move nursing home residents back to their homes. But its emergency room was still seeing about 10 to 15 percent more patients than usual.

At first SLU's emergency room filled up with people who injured themselves stumbling in the dark or picking up debris, Hakes said. Now, the hospital is seeing more patients with heat-related illnesses.

PLEASE SEE HOSPITALS | C6



Robert Tackett
of St. Charles

AFTER THE STORM | A DANGEROUS JOB

Ameren worker electrocuted

Another lineman is shocked and burned atop a pole in Spanish Lake.

By Heather Ratcliffe
and Jessica Bock
ST. LOUIS POST-DISPATCH

As up to 4,000 repair workers hung from truck booms and power poles in a race to restore electricity to desperate Ameren customers, it was the simple mistake of stepping on a hidden downed wire that killed one of them Tuesday.

Robert Tackett, 56, of St. Charles, touched an energized power line partially hidden in brush behind a Ladue mansion while surveying damage about 7:45 a.m.

Not an hour later, a contract

PLEASE SEE DEATH | A11

Wednesday, July 26, 2006
St. Louis Post-Dispatch

WHY ARE SOME OF US

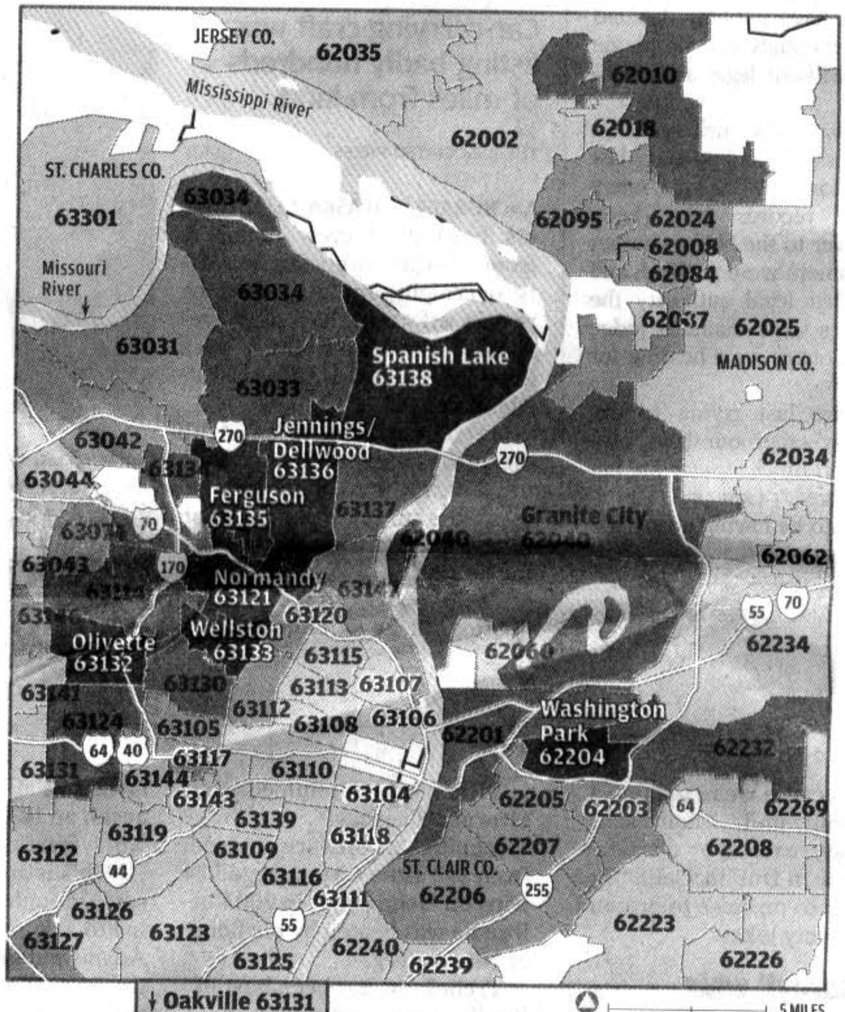
Still in the dark?

The pace of power restoration

A Post-Dispatch analysis of power outages by ZIP code shows that many communities in the northern tier of the St. Louis area have been the slowest to regain electricity. Ameren says its efforts have been hampered because of large-scale damage and because many homes in those areas are built back-to-back, restricting access.

Customers with restored power

- 80-100% restored
- 40-59% restored
- 60-79% restored
- 20-39% restored



Ten ZIP codes with highest number of power outages

ZIP code, city	Without power during peak outage times	Without power Tuesday	Percent with power restored
63129, Oakville	21,268	43	99.8%
63136, Jennings	**21,006**	**15,138**	**27.9%**
63301, St. Charles	20,595	66	99.7%
63033, Black Jack	19,178	11,150	41.9%
62040, Granite City	18,199	7,624	58.1%
63031, Florissant	17,954	7,147	60.2%
63123, Affton	16,118	505	96.9%
63125, Lemay	14,231	227	98.4%
62234, Collinsville	12,892	1,405	89.1%

Thankful or angry: Storm drew out emotions

On the radio

One of the most annoying aspects of this storm was the lack of reliable information. I was frustrated listening to the radio stations advertising that the latest storm information would be available on the 5 or 6 or 10 o'clock news or by checking Web sites. With the storm devastation in such a concentrated area, my neighbors, friends and family were powerless, too. In many emergency situations, electric power is lost, so television's "emergency broadcast system" is useless. This was a severe wind storm, but, with determination, most people could find gas, water, ice, food, batteries, cooling stations, etc. What would happen in case of a massive tornado touch-down, earthquake, etc, making roads impassable, collapsing bridges, causing casualties, flooding, evacuations, gas fires, etc.?

Radio has to be the answer for communicating. All St. Louis-based radio stations should be required to broadcast official information at designated hourly intervals when an emergency is declared. We should establish a centralized emergency communication source based on information from a trustworthy source for broadcasting to the masses. If this type is in existence, it failed.

Sue Morton | Florissant

Lest we not forget ...

Thanks to the trash collectors. They have the back-breaking job of lifting all those trash cans full of decomposed, spoiled foods. The smell alone is enough to turn a stomach. The collectors have worked very hard at each stop where cans and plastic bags are swollen with this filthy organic matter.

Jackie Hasty | Woodson Terrace

What do you say?

I am so sick of people complaining about AmerenUE not doing its job fast enough. We need to thank Ameren's workers for working so hard to get power back on around the city as fast as they could. Every morning I see out-of-state electrical trucks. This morning I was a little embarrassed for the city. I saw a whole fleet of electrical trucks from Alabama and tree cutters from Ohio. These people came to help us, and all we can do is complain. Have we even thanked them?

Carol Barrett | St. Louis County

Afterthought

AmerenUE is doing a poor job to restore the power in North St. Louis County. I have been without power since July 19. As of July 26, I have not seen nor heard of any effort to restore power to our neighborhood. I am disgusted that North County is an afterthought. What happened to any emergency contingency plan?

Tina Kennett | Hazelwood

Challenging time

To AmerenUE: Thanks for a job well done after the two storms that devastated the area. I am grateful for the hard work and long hours put in by Ameren's service people and those who came from other areas to help out in order to restore power to homes and businesses. The inconvenience we experienced was small compared to other natural disasters. This is one customer who is grateful for your response at a challenging time.

Jean Mechura | Overland

Proud St. Lousian

I am sick of the Rev. Al Sharpton racing to St. Louis to protest. I'm tremendously happy that the largest utility in the area responded better and faster than any large business entity or organization in a calamity involving hundreds of thousands of people.

I heard AmerenUE explain how power would be restored. There has never been an ethnic influence on a power grid. Ameren immediately called for thousands of electricians from all over the Midwest, and everybody was gallantly working double shifts, only to have the bulk of their work undone when another storm hit July 21.

The irreverent Mr. Sharpton already is complaining about rate hikes. Maybe people missed it, but we were told that after the stations and main lines were restored, it would be a yard-by-yard effort. Let's worry about the money when every needy person has been taken care of.

When I'm paused at a four-way stop, and my turn to cross is granted with a nod or a wave, I feel enormously proud to be a St Louisan.

P.J. Link | Maplewood

Amazing response

As one of the more than 500,000 customers who lost power for several days, let me say that it was a struggle to do without so much that we take for granted. Lights, air-conditioning, fresh and safe food, cold water and comfortable sleeping conditions.

I have heard much negative talk about AmerenUE's response. I would like to see any business respond better to 500,000 customers who all expected to be served quickly and then to be served again two days later.

I'm amazed at Ameren's quick response to the area's most destructive, massive storm in the last 50 years. No one could have foreseen such a large area being hit with such force, and hit again two days later.

To have your life interrupted for four or five days is not the end of life as we know it. It is only a hot, expensive, dark interruption. Most people have taken this experience well, with humor and grace. For those who demand instant gratification, I advise patience. We should thank God that we and our loved ones are alive and well enough to grumble about being hot and tired of the dark. For a lot of the people in this world, life is like that every day.

Kenn Avenevoli | Florissant

In the dark

The public's frustration at being kept in the dark — literally and figuratively — as to where and when the repairs were being made is unacceptable.

If AmerenUE had issued daily statements as to which area was undergoing repair and what subsequent repair was scheduled, the anxiety of those of us vainly flipping switches and futilely searching for repair trucks would have been alleviated to a large degree.

Surely someone was directing the repair crews in some kind of order. Why was this kept secret?

Mary Beth Baruto | St. Louis County

Plan? What plan?

After four nights and five days without electricity, I cannot help but feel frustration at the lack of leadership. I have to believe that the federal and state departments of homeland security contemplated scenarios in which major metropolitan areas have an electrical power crisis. After the hurricanes in the South, I have to believe that federal and state leadership considered emergency power plans, gas distribution and plans for residential care facilities. Yet I do not see such obvious hallmarks of emergency management.

Brian Stokes | St. Louis

Saturday, July 29, 2006
St. Louis Post-Dispatch
YOUR VIEWS: Letters from Readers

Sunday, July 30, 2006
St. Louis Post-Dispatch

After the storm

Measuring the response

Assessing officials | One week later, bistate divide comes clear

By Jake Wagman, Clay Barbour and Adam Jadhav
ST. LOUIS POST-DISPATCH

One week after a pair of monster storms ripped through the area, St. Louis County Executive Charlie A. Dooley held a news conference in far north county, practicing a little damage control.

The area was ground zero for the twin tempests. A rumor had circulated in the minority-heavy north county area that race was the reason many people were still without power. Dooley, an African-American, assured the community that nature was the only culprit.

Such second-guessing by residents was part of the aftermath of one of the worst blackouts ever in St. Louis. More than 700,000 homes and businesses lost power. Food went bad. Homes were destroyed. People died.

The question now is: Did our leaders do their job? The answer, it seems, is split along the Mississippi River.

In Missouri, officials have been praised for a fluid response. Leaders recognized early on the severity of the damage, set up cooling stations and evacuated the elderly and vulnerable.

In Illinois, officials have been

PLEASE SEE **RESPONSE** | C5

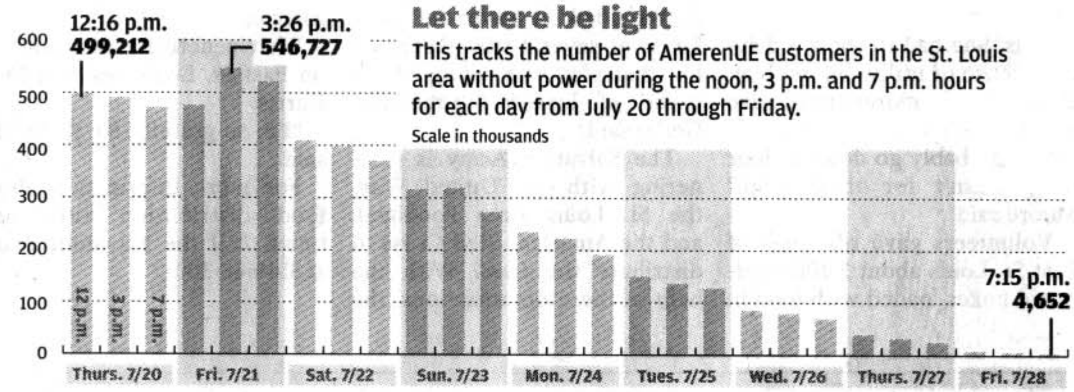
MISSOURI Officials saw severity of damage early, established cooling stations and conducted evacuations.

ILLINOIS Cities appeared unprepared, officials weren't communicating and aid wasn't sought for a week.

Let there be light

This tracks the number of AmerenUE customers in the St. Louis area without power during the noon, 3 p.m. and 7 p.m. hours for each day from July 20 through Friday.

Scale in thousands



SOURCE: AmerenUE | Post-Dispatch

Assessing Ameren | Company must take the heat

By Jeffrey Tomich and Joe Mahr
ST. LOUIS POST-DISPATCH

In Ameren's emergency operations center, a flat-screen TV displays hundreds of trouble spots. A dozen employees work the phones and computers, and one of the company's top executives glances at a digital clock timing the outage.

They never want that clock to top 72 hours.

By now — 1 p.m. on Thursday — it's approaching Hour 186.

"Obviously we didn't make our goal (on) this one," said Thomas Voss, Ameren's chief operating officer. "But Mother Nature sometimes does some things you don't expect."

As the region recovers from its worst outage ever, some local leaders, customers and regulators wonder if Mother Nature isn't the

PLEASE SEE **OUTAGES** | C4

AMEREN SAYS

Company doesn't believe anything in its system increased the likelihood or severity of outages.

CUSTOMERS SAY

Many community leaders find the company's claims suspicious.

More storms arrive | C8