Final Report

Focused Management Audit of

The Hazard Service Area of American Electric Power/Kentucky

for the

Kentucky Public Service Commission

March 24, 2003

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I. Executive Summary

A. Background

Since 1996, the Commission staff has closely monitored AEP/Kentucky's system and the level of consumer complaints, with particular attention paid to the Hazard Service Area (HSA). Annual electric system inspections have noted various projects, such as sectionalizing, right-of-way clearing, and conductor change-outs, which have been completed or were in progress. The Commission's 2001 Inspection Report noted that the service interruptions reported in AEP/Kentucky's Year 2000 outage report are probable violations of 807 KAR 5:041, Section 5(1) (Maintenance and Continuity of Service). AEP/Kentucky has invested significant capital since 1996 in an effort to increase service reliability in its service territory, and specifically in the Hazard Service Area. As a result of AEP/Kentucky's efforts, the SAIDI index for the Hazard Service Area has improved somewhat in the period 1996 through 2001, but it is still significantly higher than the average for all of AEP/Kentucky.

The main focus of this project was to review AEP/Kentucky's management and operations efforts regarding the maintenance of service quality and service reliability to customers of the Hazard Service Area. A review of AEP/Kentucky's current initiatives was included in the evaluation. It is Schumaker & Company's understanding that both the Commission and AEP/Kentucky seek viable means by which the Hazard Service Area's distribution and transmission systems can be improved and adequately maintained, providing ratepayers with an acceptable, reliable electrical system in a cost-effective manner.

Chapter II – Report Summary provides a complete summary of the major findings and conclusions contained within this review.

B. Overall Assessment

Seven overall assessments need to be addressed between AEP/Kentucky and the Kentucky Public Service Commission if this report is to be successful at improving the service quality in the Hazard Service Area. These overall assessments are contained throughout the report; however, we felt that it is important to highlight these assessments, such that action is taken on these items to ensure the successful implementation of the remaining recommendations. These seven assessments are:

AEP/Kentucky Hazard Service Area is a more difficult area to serve than other service areas.

AEP/Kentucky Hazard Service Area is a more difficult service territory compared to other AEP/Kentucky services areas. The mountainous terrain and significant tree exposure make it a more difficult service territory to provide a comparable level of service than other areas of Kentucky. In Schumaker & Company's opinion, it is clear that the Hazard Service Area is a much more difficult area to serve than areas such as Pikeville or Ashland, or other areas of Kentucky for that matter.

AEP/Kentucky has not invested the financial resources in the HSA to provide comparable service.

AEP/Kentucky has not invested the operations and maintenance or capital resources to provide the Hazard Service Area with comparable service levels within other areas of Kentucky. Many of AEP/Kentucky responses to our suggestions that they need to be spending more money in certain areas was that they are spending all that is available. AEP/Kentucky comments to the draft report clearly indicate that they do not have the money to spend in the Hazard Service Area. This is an issue that must be addressed if service levels are to improve in the Hazard Service Area.

AEP/Kentucky has not quantified the financial resources required in the HSA to provide comparable service.

AEP/Kentucky has not quantified the level of operations and maintenance or capital expenditures that would be required to provide a comparable level of service quality in the Hazard Service Area. It will clearly cost more to provide the same level of service within the Hazard Service Area than other areas of Kentucky. Many of the recommendations (specifically, recommendations *II-1*, *II-2*, *II-4*, *II-5*, *V-1*, and *V-3*) contained within this report are designed to direct AEP/Kentucky to develop such a bottom-up estimate of the expected costs.

AEP/Kentucky has not sought rate relief, although their earnings have continually decreased over the last several years while service levels have not improved.

Within the Hazard Service Area, SAIFI, CAIDI, and SAIDI numbers have varied little over the last six years with the SAIFI and SAIDI numbers trending slightly down, but CAIDI remaining relatively unchanged. In almost all cases, the Hazard Service Area has the highest (worst) results within AEP/Kentucky.

AEP/Kentucky's last rate case was in 1991 and was settled. AEP/Kentucky has not had a fully litigated general rate case in many years (not since the 1980s). Although AEP/Kentucky's allowed rate of return was set at 16.5% at that time, AEP/Kentucky has not earned that level in many years, with the last several years being reported in the 8% to 9% range. AEP/Kentucky has been under a base rate moratorium since the settlement agreement was approved in Case No. 99-149 Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and Southwest Corporation Regarding a Proposed Merger, Order dated June 14, 1999. In the settlement agreement at page 3, the parties agreed. "Absent a force majeure, KPCO will not file a petition, which if approved, would have the effect, either directly or indirectly, of authorizing a general increase in basic rates and charges that would be effective prior to January 1, 2003 or three years from the effective date of the merger, whichever is later…" The moratorium ends in the summer of 2003.

Clearly, AEP/Kentucky needs to find a way to spend more on operations and maintenance or capital expenditures in the Hazard Service Area if they have any possibility of providing comparable service quality in that service area.

AEP/Kentucky needs to investigate all options for being able to commit more resources to the Hazard Service Area.

AEP/Kentucky is a regulated utility and is not striving to provide comparable service.

AEP/Kentucky operates as a regulated utility within the Commonwealth of Kentucky. As a regulated utility, its rates are set by the Kentucky Public Service Commission in a manner that should cover its costs of operations and provide an adequate return to its shareholders. In return, AEP/Kentucky has an obligation to provide service to residential, commercial, and industrial customers within its service territory. In essence, in exchange for its regulated monopoly status, AEP/Kentucky must provide equal service to all customers within its service territory (the franchise area), what some individuals would refer to as the "regulatory compact." The rates that have been set for providing this service are the same for each rate class throughout the AEP/Kentucky service territory. Given the uniformity of rates, it would be expected that AEP/Kentucky would strive to provide the same level of service throughout its service territory.

It would also be expected that AEP/Kentucky should strive to provide equal service for all customer classes within Kentucky and that rates should be adequate to permit AEP/Kentucky to provide such service. However, responses provided throughout the draft report indicated that AEP/Kentucky's viewpoint has strayed from the traditional "regulatory compact" for providing comparable service. By its own admission, AEP/Kentucky has decided to differentiate the level of service that is provided its customers based on various factors versus striving to provide the same level of service throughout its service territory.

Summary

This report identifies specific recommendations that should be implemented by AEP/Kentucky in responding to our overall assessments. AEP/Kentucky provided comments to these findings, conclusions, and recommendations throughout the development of this final report. These comments identified some differences of professional opinion and some misunderstandings of the issues in the final report. Although Schumaker & Company consultants tried to be clear in our development of this final report, the issues involved are complex and need to be addressed in a systematic manner over the next several years by all parties including the management of AEP/Kentucky and Kentucky Public Service Commission staff and Commissioners.

It is clear that improving service quality in the Hazard Service Area requires "money." The exact amount of additional money that will be required is something that the implementation of many of our recommendations will help identify. Depending on the amount of money involved, a method for making those financial resources available for the Hazard Service Area will need to be identified. These items will need to be worked out over the next year as KPSC staff monitors AEP/Kentucky's implementation of these recommendations.

The remainder of this chapter provides some background surrounding these investigations, summarizes all of the findings and conclusions contained within the report, and presents a summary of recommendations.

C. Report Background

The efficiency and effectiveness of the management of transmission and distribution assets within an electric utility directly translates into the electric system reliability experienced by customers. As such, based on generally accepted electric utility industry standards, an effective transmission and distribution operation should include the following characteristics:

- The decision-making process regarding the management of these transmission and distribution assets should be based on more than personal experience or prior practices and, as such, should incorporate the use of extensive quantitative data available from within the organizational information technology resources.
- The overall organization of the various functions related to electric distribution should be efficient and effective with clearly defined roles and responsibilities, staffing levels that are workload driven, and adequate consolidation of activities.
- The work management tools used for managing work activities should include planning, scheduling, and resource loading techniques and have a level of detail sufficient for adequate control.
- The facilities and equipment that are used by distribution personnel should be adequate and well maintained.
- There should be a well-developed maintenance management system to identify maintenance items, schedule maintenance work, record costs and durations of equipment failures, and record maintenance histories.
- There should be a well-developed preventative maintenance management system in place for major substation equipment to correct unfavorable station maintenance.
- There should be systematic procedures and practices in place for evaluating demand and energy forecasts and their impact on new facility requirements.

- The processes used to manage the engineering and design of projects should identify responsibilities and authority, and should promote quality, cost-effective work.
- Well planned and fully functional vegetation management and animal protection programs should be in place to minimize system service disruptions to the greatest extent possible.
- Proper work management and manpower planning programs should be in place to facilitate the capability to utilize the existing workforce to the maximum extent possible at the greatest level of efficiency.

History

The concerns regarding the issue of AEP/Kentucky's electric service reliability in the Hazard Service Area first became a public issue as a result of electrical outages that occurred during a November 7, 1995 election. Electrical outages at several polling locations generated rumors of sabotage. AEP/Kentucky appeared before the Grand Jury to indicate that the outages were due to the failure of aging equipment, not sabotage. The Grand Jury was satisfied with AEP/Kentucky's response, but requested that the Kentucky Public Service Commission (KPSC) investigate the frequent and prolonged outages residents in the area experienced. In response to this request from the Grand Jury, the KPSC performed investigations and issued a May 23, 1996 Staff Report that addressed the issue.

This report initiated numerous activities by AEP/Kentucky to address the subject concerns, many of which were subsequently determined to be capital projects that had been planned prior to the Staff Report investigation. The report did review design characteristics of the distribution system and found them to be in need of improvement. In particular, problems were identified with heavily loaded feeders/substations and with effectively operating the 34.5 kV system. AEP/Kentucky maintains both 12 kV and 34.5 kV distribution lines as well as higher voltage transmission lines in this service area. The projects mentioned in the 1996 report were planned by the company in an effort to address the findings, but AEP was unable, at the time, to accelerate implementation of the Commission staff's recommendations. Over the course of time, these projects were completed as requested by the Commission staff.

Since 1996, the Commission staff has continued to closely monitor AEP/Kentucky's system and the level of consumer complaints. Annual electric system inspections have noted various projects, such as sectionalizing, right-of-way clearing, and conductor change-outs, which have been completed or were in progress. The Commission's 2001 Inspection Report noted that the service interruptions reported in AEP/Kentucky's Year 2000 outage report are probable violations of 807 KAR 5:041, Section 5(1) (Maintenance and Continuity of Service). AEP/Kentucky has invested significant capital since 1996 in an effort to increase service reliability in its service territory, and specifically in the Hazard Service Area. As a result of AEP/Kentucky's efforts, the SAIDI index for the Hazard Service Area has improved somewhat in the period 1996 through 2001, but it is still significantly higher than the average for all of AEP Kentucky, as demonstrated in *Exhibit I-1*.

Exhibit I-1
AEP/Kentucky Reliability Performance Statistics

Hazard Service Area

	No Exclusions			Major Storms Excluded		
Year	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
1996	2.60	4.00	10.400	2.60	4.00	10.400
1997	2.55	3.44	8.786	2.55	3.44	8.786
1998	2.98	6.05	18.047	2.48	3.93	9.731
1999	2.63	6.17	16.215	2.33	3.34	7.796
2000	2.40	4.44	10.647	2.02	3.91	7.879
2001	3.00	5.28	15.824	2.17	3.77	8.173

AEP/Kentucky Service Area

2001	2.16	4.51	9.75	1.66	3.29	5.47

The problems experienced by AEP/Kentucky ratepayers in the Hazard Service Area were particularly prevalent for the customers located near the City of Buckhorn, Kentucky. This area has a long history of service reliability problems, which were culminated in an outage on Christmas Day 2001, lasting most of the day. This event prompted the citizens of Buckhorn to develop a petition that was transmitted to the Kentucky Public Service Commission. This petition resulted in particular emphasis on the problems that were being experienced in the area and, to a large extent, resulted in the decision to perform this audit.

The Commission has acknowledged that the Hazard Service Area includes forested mountainous terrain, which presents difficult challenges to AEP/Kentucky for improving overall service quality. However, it is the stated belief of the Commission that there is room for significant improvement in service reliability for AEP/Kentucky's customers in the Hazard Service Area. The achievement of this objective is the specific focus of the audit.

AEP/Kentucky Background Information

AEP/Kentucky is a generation, transmission, and distribution company supplying electric power to retail customers in all or portions of the 20 eastern Kentucky counties as shown in *Exhibit I-2*:

Exhibit I-2
Counties in AEP/Kentucky Service Territory

Boyd	Floyd	Leslie	Morgan
Breathitt	Greenup	Letcher	Owsley
Carter	Johnson	Lewis	Perry
Clay	Knott	Magoffin	Pike
Elliot	Lawrence	Martin	Rowan

As of December 31, 2001, AEP/Kentucky served 172,120 total retail consumers. AEP/Kentucky's total utility operating revenue for the year ended December 31, 2001, was $1.659 billion with net utility operating income of $49.40 million. For the pay period ending December 31, 2001, AEP/Kentucky had 429 full-time employees.

In prior years, AEP/Kentucky was divided into three districts: Ashland, Hazard, and Pikeville. AEP/Kentucky currently has only one district operating in Kentucky, that being the Pikeville District, which is headquartered in Pikeville, Kentucky and is responsible for the operations of the Pikeville, Ashland, and Hazard, Kentucky Service Areas and the Logan, West Virginia Service Area. The Pikeville District Manager reports to the Charleston Region Vice President, located in Charleston, West Virginia. The Charleston Region includes AEP service territories in Kentucky, West Virginia, Virginia, and Tennessee.

Objectives and Scope of the Audit

The main focus of this project was to perform a review of AEP/Kentucky's management and operations efforts regarding the maintenance of service quality and service reliability to customers of the Hazard Service Area. A review of AEP/Kentucky's current initiatives was included in the evaluation. It is Schumaker & Company's understanding that both the Commission and AEP/Kentucky seek viable means by which the Hazard Service Area's distribution and transmission systems can be improved and adequately maintained providing ratepayers with an enhanced, reliable electrical system in a cost-effective manner.

Schumaker & Company understands that the Commission intended for this to be a focused review of service quality and reliability in the Hazard Service Area. However, it is important that such a review also encompass issues relating to the practices and provision of service throughout the entire AEP/Kentucky system.

The scope of this focused review encompassed, but was not limited to, the following task areas to a greater or lesser extent:

- AEP/Kentucky's Transmission and Distribution (T&D) Organization
- AEP/Kentucky's T&D System Capital Budgets and O&M Budgets and Expenditures
- AEP/Kentucky's Reporting of System Reliability Information Procedures
- AEP/Kentucky's T&D Planning
- AEP/Kentucky's T&D System Design
- AEP/Kentucky's T&D Protection Program
- AEP/Kentucky's T&D Lightning Protection Program
- AEP/Kentucky's T&D System Operations
- AEP/Kentucky's Line Inspection and Maintenance and Repair Programs
- AEP/Kentucky's T&D System Condition
- AEP/Kentucky's Substation Evaluation
- AEP/Kentucky's T&D System Staffing
- AEP/Kentucky's Vegetation Management Program
- AEP/Kentucky's Animal Protection Program
- AEP/Kentucky's Work Management and Manpower Planning Practices

Review Approach

Schumaker & Company performed a four-phase review process to address the KPSC's requirements. The major phases are listed below:

- Phase I: Orientation and Project Planning
- Phase II: Detailed Review
- Phase III: Final Report Preparation
- Phase IV: Action Plan Preparation

Based on the task areas reviewed, it was the intention of Schumaker & Company to evaluate the ability or inability of AEP/Kentucky to provide the same level of service to customers of the Hazard Service Area as provided to other AEP/Kentucky service areas. The review focused on determining what improvements, if any, could be made in the management and operations of the Hazard Service Area of AEP/Kentucky. In broad terms, the scope of "improvements" includes measures and strategies for:

- Service and reliability improvements
- Cost savings
- Productivity gains
- Efficiency increases
- Addressing competition

Major Areas of Investigation

Our major areas of investigation were broken down into four review areas, specifically:

- Asset Management – Decision Support Systems and Information Technology
- Engineering Design
- Electric Transmission and Distribution Operations
- Vegetation Management and Animal Protection

Our principal objective in evaluating these AEP/Kentucky business and operations functions was to verify that the associated activities were being conducted in an effective and efficient manner, that the functions performed support the company's overall strategic goals, and that the established management controls and systems provide management with an adequate ability to ensure appropriate levels of service quality and reliability in the Hazard Service Area. The ultimate objective of this work plan was the identification of cost-effective improvements in management, design, and operations that will result in more cost-effective operation and/or better service to AEP/Kentucky customers in the Hazard Service Area.

In the course of conducting this audit the Schumaker & Company project team interviewed more than forty (40) individuals, the majority of whom were employees of AEP or AEP/Kentucky. Additionally, our consultants interviewed the Mayor of the City of Buckhorn, Kentucky to gain his perspective into the problems that had been experienced by its citizens. We also requested and reviewed over 160 documents that provided data on or information about AEP/Kentucky's organization and operations in the Hazard Service Area.

Report Layout

This report is organized into the following chapters:

- Chapter I – Executive Summary
- Chapter II – Project Summary
- Chapter III – Asset Management – Decision Support Systems and Information Technology
- Chapter IV – Engineering Design
- Chapter V – Electric Transmission and Distribution Operations
- Chapter VI – Vegetation Management and Animal Protection

Each of the four chapters focused on functional areas (Chapters III through VI) contain background and perspective information on the specific functional area, the resultant findings and conclusions, and associated recommendations.

Project Team

The names and positions of the Schumaker & Company project team consultants and the functional areas to which they were assigned are listed in *Exhibit I-3* below.

Exhibit I-3
Project Team Consultants

Consultant	Project Team Position	Functional Area Assigned
Dennis Schumaker, PMP, CMC	Engagement Manager	Asset Management
Siegfried Guggenmoos	Senior Consultant	Vegetation Management and Animal Protection
Martin Murphy, PE	Senior Consultant	Engineering Design. Electric Transmission and Distribution Operations
William Braatz, PE	Senior Engineer	Engineering Design
Kenneth Hobson, PE	Senior Engineer	Engineering Design

Schumaker & Company would also like to take this opportunity to express our profound appreciation to the Kentucky Public Service Commission Management Audit Branch management and staff who worked closely with our consulting team on the conduct of this project. Those managers and staff members include Messrs. Mike Nantz, John Rogness, Charles Bright, David White, and Aaron Greenwell. The insight, perspective, and guidance that were provided to our consulting team by these individuals was invaluable to us in our successful completion of this project.

D. Findings and Conclusions Summary

The following text contains a summary of our overall findings and conclusions for each of the four major areas of investigation. More detail and supporting information can be found in each of the individual chapters.

Chapter II – Asset Management – Decision Support Systems and Information Technology

Asset management can be thought of as a portfolio approach to managing the physical assets of an electric utility to maximize the overall asset performance and profitability while meeting regulatory obligations. During our investigations, we evaluated the current practices of AEP/Kentucky relative to the use of decision support systems and information technology in the management of electrical assets (both transmission and distribution) to determine (a) whether the processes used by AEP/Kentucky are consistent with currently accepted levels of technology for the electric utility industry in general, (b) whether these processes are properly designed to support the AEP/Kentucky organization in providing superior service to its customers, and (c) whether AEP/Kentucky attempts to tie expenditures to performance levels.

Although Schumaker & Company reviewed the activities of the Transmission Asset Management organization, it was determined early in our investigations that most of the issues or problems that caused our investigations stemmed from issues in distribution, rather than transmission, assets. Transmission assets account for only a small portion of the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) indicators. As a result, our investigations were primarily focused on distribution asset management activities.

Technology Systems

Over the last five years, AEP has made significant upgrades in their technology and systems that are involved in responding to customer outages and reporting on those results. The call center agent enters the information into the Trouble Entry & Reporting system (TERS), an internally developed system, implemented around 1995, that collects information on the outage and also supports the ongoing reporting of progress on outage restoration such that information can be relayed to the customer if they call in again or if additional customers affected by the same outage call in.

That trouble ticket then flows to the PowerOn software (implemented in 2002) where the tickets are analyzed and a failed device (transformer, fuse, breaker, etc.) is predicted. All of this information can be displayed on geographic maps, via an interface to the Small World system that was implemented in the last several years, in the Distribution Dispatch Center (DDC) in Roanoke, VA, and information on the "predicted" failed device can be relayed to the Servicer (a field technician who acts as the first responder to outage situations) who is dispatched to identify the outage cause. Once the outage is corrected, information is collected and summarized on a Trouble, Damage & Interruption Report that is then reviewed and entered into the Historical Outage Information System (HOIS). HOIS is an Oracle database that was implemented in 2001 to replace the previous Distribution Outage Reporting (DOR) system.

Outage Reporting and Monitoring (Call Center and Dispatch)

All initial customer calls on outages are handled in call centers, collectively called the Solutions Center. The Solutions Center is currently organized into an East and West configuration, although AEP is evolving toward a national virtual call center configuration, once the company's systems are capable of supporting such an operation. The Solutions Center is full service 7x24 for all customers. Throughout the management of an outage, AEP/Kentucky has the ability to keep the customer informed. Customer surveys that have been performed within the industry have repeatedly shown that the ability to keep the customer informed is one of the key capabilities that customers want during outages. AEP has vendors who do third-party customer satisfaction surveys. AEP also has a complaint tracking mechanism to monitor complaints.

Capital and Operations and Maintenance Budgeting

The budgeting process is predominately a top-down process. Asset Management is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. These budgeted amounts are initially divided among the Asset Management groups and the regions by the Asset Management organization. As such, budgets are not necessarily requirement based. Budgets are based more on prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. This approach results in a setting of budgets such that field personnel are only left with deciding how "best" to spend the allotted dollars.

Reliability Programs

Asset Management manages several different reliability programs that specifically address the hardware aspects of reliability. Within the Asset Management organization various reliability programs exist that have been designed to ensure that certain ongoing preventative maintenance activities are performed. These programs include such things as: pole replacements, pole reinforcement, recloser replacement, lightning protection, animal mitigation, URD inspection and replacement, overhead circuit inspection and upgrade, pole ground-line treatment, small wire replacement, and maintenance. All of the above categories are divided on a regional basis by program.

Reliability programs are not specifically designed to make improvements in SAIFI, Customer Average Interruption Duration Index (CAIDI), and SAIDI by targeting improvements in frequency, duration, or number of customers. AEP/Kentucky has recently started trying to tie some of its reliability programs into improvements in SAIFI. In particular, a model has been developed based on theoretical assumptions that will require several years of analyzing actual field results to validate the model. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality.

Field crew staffing levels need to be approached from a response effectiveness analysis. Hazard Service Area staffing has been significantly reduced over the last five years. Although AEP/Kentucky has made many changes in the last five years that could support some of the reductions, such as the introduction of new computer systems, the most sensitive area with respect to system reliability is the Distribution Line area. One of the primary roles of Distribution Line personnel is to respond to outages. It has become even more important as response staff has been decreased.

Outage Results

Outages results are getting worse. The total number of customers impacted from January to July of 2001 compared to 2002 has increased by 55% and the customer minutes by 40%. Some of this increase might be explained by more accurate reporting as a result of the improved systems (specifically

PowerOn and HOIS). However, to the extent that this increase is not a result of improved reporting, it could be indicating that service levels are getting worse.

Chapter III – Engineering Design

The responsibility for the design engineering function is divided among the Charleston Region engineering groups located in Charleston, WV and Roanoke, VA; a Regional Engineer located at the Hazard Service Center; and Engineering Technicians located at the Hazard Service Center. The Station Resources group in Roanoke does substation design. The Technical Services group in Hazard does the design of the customer distribution line installation and upgrade projects.

Engineering Design Process

The design engineering function as it is performed by various groups within AEP for the benefit of the Hazard Service Area operations is commensurate with contemporary electric utility industry standards. The division of responsibilities between regional and local groups is properly structured to allow significant local input, while still adhering to regional goals and objectives. The number of engineers on staff in both the regional offices and the Hazard Service Center is appropriate in consideration of the normal workload. All of the engineering groups have access to the tools, information, and systems that they need to properly support the operation of the system.

Engineering Design Standards

AEP maintains a Central Standards Group, located in Columbus, OH, which is responsible for development and maintenance of company-wide standards for AEP in relation to the design engineering function. One person from the Central Standards Group is located in each of the regions to ensure that proper communication exists between the Engineers in the region and those of the Standards Group. The Central Standards Group engineer for the Hazard Service Area is located in Roanoke, VA. Engineering standards documentation is currently being updated with the intention of merging AEP standards and Central and Southwest (CSW) standards to create one unified set of standards for AEP nationwide.

The AEP Central Standards Group provides the engineering staff with a robust and up-to-date set of design standards to use in the completion of their work. The AEP Central Standards Group does a good job of maintaining and updating the engineering design standards, as witnessed by their current efforts to merge the design standards of AEP and CSW to have greater standardization and to avail themselves of the best of both sets of standards. These continuing efforts ensure that the engineering designs created by the AEP design engineering groups are based on the latest and most complete standards possible.

Chapter IV – Electric Transmission and Distribution Operations

The Transmission Line Operations organization and Distribution Line Operations organization of AEP/Kentucky are responsible for the construction, operation, maintenance, and repair of the AEP/Kentucky transmission and distribution grids, respectively. For the Hazard Service Area, the overall management of this function is located in Pikeville, KY, with local field management provided out of the Hazard and Whitesburg Service Centers. Dispatching for trouble and outage restoration is performed out of the centralized Distribution Dispatch Center (DDC) in Roanoke, VA.

Management and Organization

Our investigations revealed that the management of the Line Mechanics and Servicers is appropriate and adequate for the current staffing levels and workload. The organization and systems used to manage the Transmission and Distribution Line field operations forces are consistent with the requirements for proper management and control of an organization of that size and responsibility. The spans of control that were observed were well within accepted standards for an electric utility field operations organization. The systems and reports that were available as tools to the management of the operation were appropriate to support them in the performance of their assigned tasks.

Staffing Levels

The number of Servicers (those employees who handle distribution installation, maintenance, and restoration duties) assigned to the Hazard Service Area is not adequate to handle the current workload in an efficient manner. This results in two significant problems, specifically:

- The limited number of Servicers in the Hazard Service Area results in a reduced ability to restore service in a timely manner during storm situations. With the service restoration jobs divided among a smaller number of Servicers, response time and times to restoration will be longer than if a larger contingent of Servicers were available. While there certainly are practical and economic limits to the number of Servicers that should be in place, the number that currently exists is smaller than is needed to provide satisfactory restoration times. Additionally, when the Servicers are on vacation or out-of-town, the coverage of their responsibility often is transferred to a Line Mechanic. While the Line Mechanics have the technical capability to perform the required restoration work, their lack of daily familiarity with the tasks involved and with the geography of the area renders them less efficient than a Servicer in performing the same work. Additionally, situations were identified in which certain jobs or types of work were delayed until the Servicer returned to duty.
- The Servicers in the Hazard Service Area are working a large amount of overtime, which is attributable to the large number of after-hours callouts and a relatively small number of Servicers to handle the work load. Review of overtime data for the years 2000 through 2002 reveals that all of the Servicers in the Hazard Service Area have been working significant quantities of

overtime during this period. This is particularly true in the Perry County area, which includes the City of Hazard. Because this data reflects the number of hours that are paid for (rather than the number of hours that are actually worked), the numbers are somewhat inflated. However, even with this taken into consideration, the Servicers are still working very large amounts of overtime. When Servicers are working this much overtime, it would be expected that there would be a declining efficiency of the work as the number of hours worked increases. Additionally, at some point the number of hours worked becomes a concern relative to the safety of the workers. Having a larger number of Servicers assigned to the HSA would serve to reduce the amount of overtime worked by each of the individual Servicers, thereby reducing concerns with work performance and safety. Moreover, a larger number of Servicers would be expected to cut down on the amount of time that it takes to restore service in a storm situation due to an enhanced ability to spread the workload across more field personnel.

Radio Communications

Our investigations revealed that the current radio communications system does not provide adequate radio coverage in all areas of the HSA, leading to the presence of significant “dead spots” where radio communications between the field crews and the DDC and the Schedulers is impossible. Such significant radio communications dead spots were found to exist in two of the counties in the Hazard Service Area. This is a significant concern due to crew efficiency and safety considerations. However, a plan is in place to resolve these communications problems by the year 2004 through the construction of several new antenna facilities.

Tree-Related Outages

Most of the outages that are repaired by the Servicers are caused by trees. Interviews with several Servicers revealed that, in their collective opinion, trees are the single largest cause of outages experienced in the Hazard Service Area. This is particularly true in summer, because trees are in leaf and they have a greater tendency to fall or for branches to break off due to wind.

The rights of way that have been obtained by AEP/Kentucky in the Hazard Service Area are not wide enough in many cases to adequately prevent tree-related damage. Interviews with several of the Servicers revealed that, in their collective opinion, the insufficient width of many rights of way is the immediate cause of many of the service outages that they respond to. It was their opinion that widening the rights of way would eliminate a significant number of tree-caused outages.

Transmission and Distribution Operations

The design and operation of the transmission system does not have a deleterious effect on reliability in the Hazard Service Area. The transmission system is well designed and operated and is not a significant factor in the reliability problems that have been experienced in the Hazard Service Area. The problems that have been experienced are much more directly related to the distribution system, especially in relation to deficiencies in the widths of existing rights of way. This is primarily because the height at which the transmission lines are strung is high enough to allow them to avoid the majority of problems that occur due to tree-related damage. The distribution lines, being positioned at a lower elevation, are much more susceptible to tree-related incidents. The maintenance program for the substations that are located in the HSA is appropriate and consistent with industry standards.

The distribution and transmission dispatching functions are performed in a manner that is consistent with industry standards. The operations of the Roanoke Distribution Dispatch Center (DDC) were observed and found to be consistent with accepted industry standards. Centralization of the operation in Roanoke has strengthened the DDC's ability to respond to emergency situations. There is a significant emphasis placed on continually improving the dispatching process to provide better and more comprehensive support to the field crews.

Chapter V – Vegetation Management and Animal Protection

Following a merger in 2000, American Electric Power centralized the Forestry group, led by a manager in corporate headquarters, to deliver its vegetation management program. This is a positive move as decentralized programs are subject to changing local priorities and pressures and often see the vegetation management budget reassigned to other emerging priorities. Across the utility vegetation management industry, decentralized control of vegetation management funding decisions have a history of producing hotspotting programs; that is programs that are completely reactive rather than planned, managed programs. American Electric Power has taken advantage of one of the opportunities afforded by centralized control of the vegetation management program. It has entered into a sole source contract for all but the aerial components of vegetation management services. The contract is positive for American Electric Power in that it guarantees cost savings.

While there have been some tree-caused transmission outages over the last five years, they are infrequent. Tree-caused service interruptions are a distribution issue, accounting for more than 40% of all unplanned distribution outages in 2001 and 2002. The Hazard Service Area faces an enormous challenge in managing tree-caused service interruptions. Much of the Hazard Service Area is rural with a low customer density and a substantial percentage of the power lines running across forested country. Tree exposure on power lines is extremely high, estimated at greater than 90% in rural areas. The terrain is mountainous, making it difficult to detect and repair tree-caused outages.

Vegetation Management Program Practices

There are some very positive aspects to AEP/Kentucky's vegetation management program. System level guidelines, which encourage tree removals, herbicide use, and the elimination of branch overhangs, contribute positively to improving reliability and lowering maintenance costs. Forestry staff is very knowledgeable and competent. The competence is illustrated in the extensive use of herbicides; excellent control of power line incompatible species on herbicide-treated rights of way; herbicide maintenance cycles based on the objective of tapping into biological control, while recognizing the succession pressure for re-invasion;, a customer notification procedure that results in only 3% refusals for herbicide application; a species selective or prescriptive approach; an industry-leading tree removal rate; excellent pruning quality; and a willingness to examine and adopt alternative maintenance practices such as aerial trimming. The prescriptive approach reduces costs by avoiding or reducing the amount of work performed and fosters the establishment of a power line compatible vegetation community. The current pruning quality is so high as to leave no room for improvement in suppressing either the amount or rate of regrowth.

Tree-Related Outages

In spite of good policy, competent staff, and industry best practices, tree-related outages are increasing and a continuation of the current program will not reverse this trend. The pruning program is about two years behind, resulting in a very high need for hotspotting. As hotspotting is rightly recognized as being inordinately expensive, it is minimized. This focus on cost effectiveness, however, leaves the trees to grow into conductors and cause outages. As a result, tree-caused service interruptions from trees within the right of way have been increasing exponentially since 1996. While the use of herbicides and aerial pruning will lower maintenance costs over the long term, it should not be anticipated that the savings would be adequate to significantly impact the pruning maintenance cycle.

Funding

If AEP has the proper policies, staff, and vegetation management practices, then why is the vegetation management program not producing level or decreasing tree-related outages? Quite simply, the Hazard Service Area vegetation management program is under funded. The current condition of rights of way and evident maintenance cycles indicates under funding is not a recent but rather a long-standing condition. The extent of the under funding is not known, as there is no inventory of the tree workload. Tree-related service interruptions can be managed if vegetation management funding is responsive to the actual tree workload. There is a preferred way to determine the funding requirements. An inventory of the cyclical work, the amount of tree exposure, and derivation of the local tree growth and mortality rates must be undertaken and form the basis for budgeting. Any other approach to budgeting for vegetation management lacks the requisite rational foundation and, because tree workload expands exponentially, constitutes a costly, high risk guess. The present vegetation management budgeting process is largely top down driven. Local staff annually compiles a list of work required, but they indicate that funding is never sufficient to complete all the identified work. Thus, vegetation management funding is divorced from need. A budgeting process based on objective data and need, with flexibility to be responsive to unusual conditions such as drought or pest infestations, is required. In this regard, it is suggested that an inventory be used to establish maintenance cycles, their costs, the amount of backlog, a reasonable timeframe for the completion of the backlog, and the associated costs.

American Electric Power uses asset management strategies, which are useful in prioritizing where allocation of resources will provide the best return in line security. However, asset management strategies do not ensure funding of all the vegetation management work required in any given year.

Tree-caused outages are subdivided into those arising from trees either within or outside the right of way. Funding based on the actual tree workload will provide a pruning cycle that minimizes service interruptions from within right-of-way trees. A 10% to 15% reduction in SAIFI is a realistic outcome. Trees outside the right of way are the single largest cause of unplanned service interruptions. Some of these outages may be due to the in-growth of lateral branches, which the aerial trimming seeks to address, but typically these outages arise from tree failure. While the Forestry group is responsive to emergent conditions, such as increased tree mortality due to the southern pine bark beetle, there does not appear to be a recognition of or strategy to reduce the extent of tree exposure on lines. AEP Forestry practices in this regard are typical of the utility vegetation management industry and, thereby, are not responsive to the facts of remote, mountainous terrain with the exceptionally high tree exposure found in the Hazard Service Area. Remoteness, steep terrain, and the destructive nature of tree failures means outages from trees outside the right of way have long durations. Vegetation management practices cannot address the duration of such outages, but can influence frequency of occurrence. There are some AEP/Kentucky initiatives that serve to reduce the extent of tree exposure. Most significant is moving cross-country lines to the roadside. This significantly decreases the incidence of tree-caused outages by substantially reducing tree exposure on at least one side of the line. Better access will also facilitate locating and repairing tree-related outages, decreasing the outage duration.

With funding based on the actual tree workload, the AEP/Kentucky vegetation management program, as currently delivered, will improve system reliability and be cost effective. Further gains in reliability can be achieved via strategies that reduce the amount of tree exposure, particularly in locations where outage durations tend to be long.

Animal Control

Animal control practices are responsive and adequate to effectively manage animal-caused service interruptions.

E. Summary of Recommendations

The following pages contain a list of the recommendations contained within the report.

Recommendation Listing

Recommendation Number	Description	Page Number
Recommendation II-1	Develop a more appropriate approach to determining capital and operations and maintenance funding levels (Refer to Finding II-4, Finding II-6, and Finding II-7).	49
Recommendation II-2	Each circuit within the Hazard Service Area should be analyzed and a reliability improvement plan developed. (Refer to Finding II-6 and Finding II-7).	49
Recommendation II-3	Maintain historical information on operations and maintenance and capital planning processes. (Refer to Finding II-5).	50
Recommendation II-4	Develop a methodology for specifically tying capital and operations and maintenance investments to reliability indicators (Refer to Finding II-6 and Finding II-7).	50
Recommendation II-5	Use statistical methods for establishing field force staffing levels (Refer to Finding II-8).	50
Recommendation II-6	Closely monitor performance indices for adverse trends (Refer to Finding II-9).	51
Recommendation II-7	Develop a method for addressing momentary outages (Refer to Finding II-10).	51
Recommendation IV-1	Perform investigations to ensure that the new Severn Trent System software package has the capability to communicate all forms of jobs to the Servicers. (Refer to Finding IV-2).	85
Recommendation IV-2	Design the training program to be administered to the Servicers on the use of of the new Severn Trent System in such a way as to ensure that the Servicers are able to avail themselves of the full capability of their laptop units and the software thereon. (Refer to Finding IV-3).	85

Recommendation Listing

Recommendation Number	Description	Page Number
Recommendation IV-3	Evaluate the Servicer workload and outage restoration statistics to determine the optimal number of Servicers that should be on staff in the Hazard Service Area. (Refer to Finding IV-4 and Finding IV-5).	86
Recommendation IV-4	Develop a software application that would allow the Distribution Line managers to track and monitor the number of overtime hours that are actually worked as opposed to those which are paid for. (Refer to Finding IV-6).	86
Recommendation IV-5	Continue with the established plan to improve the radio communications network in the Hazard Service Area (Refer to Finding IV-7).	86
Recommendation IV-6	Review the current policy on rights of way to determine if improvements could be made that would have a beneficial impact on service reliability in the the Hazard Service Area. (Refer to Finding IV-9).	87
Recommendation IV-7	Develop and implement a feedback mechanism to inform the Servicers and field crews of the status of the Tree Condition Reports that they have submitted. (Refer to Finding IV-10).	87
Recommendation IV-8	Continue the efforts that have been undertaken to improve the quality and consistency of the data that is reported to the KPSC. (Refer to Finding IV-11).	87
Recommendation IV-9	Implement a full version of the PowerOn software in the Hazard Service Center for use in daily operations and storm restoration activities. (Refer to Finding IV-12).	87
Recommendation IV-10	Review the potential for utilizing the automated field crew routing optimization capability that is built into the Small World software application. (Refer to Finding IV-13).	88
Recommendation V-1	Determine the annual vegetation management workload increment. (Refer to Finding V-7).	108
Recommendation V-2	Establish pruning cycles based on measured average tree growth. (Refer to Finding V-4).	108
Recommendation V-3	Budget for vegetation management based on the annual workload increment. (Refer to Finding V-8 and Finding V-9).	109
Recommendation V-4	Use hotspotting to minimize tree-related outages until the system is on a sustainable pruning cycle. (Refer to Finding V-5).	109
Recommendation V-5	Develop and implement practices designed to manage tree-caused outages. (Refer to Finding V-6, Finding V-10, and Finding V-11).	110
Recommendation V-6	Introduce contractor agreements that ensure effective costs are competitive. (Refer to Finding V-3).	112

II. Asset Management

Asset management is a relative new term (concept) as applied to the electric utility industry. Over the last several years, much discussion has been held regarding new business models for the deregulated electric utility industry and the concept of "asset management" has evolved. Asset management can be thought of as a portfolio approach to managing the physical assets of an electric utility to maximize the overall asset performance and profitability while meeting regulatory obligations.

Schumaker & Company investigated and evaluated the current practices of AEP/Kentucky relative to the use of decision support systems and information technology in the management of electrical assets (both transmission and distribution) to determine (a) whether the processes used by AEP/Kentucky are consistent with currently accepted levels of technology for the electric utility industry in general, (b) whether these processes are properly designed to support the AEP/Kentucky organization in providing superior service to its customers, and (c) whether AEP/Kentucky attempts to tie expenditures to performance levels. Some of the activities that we performed included:

- Evaluated the decision support systems used by AEP/Kentucky in identifying construction and maintenance activities relative to transmission and distribution assets
- Assessed the use of internal data (contained within the various company databases) in supporting operations and providing adequate and timely information for rational management decision making regarding transmission and distribution assets
- Reviewed the current management and operational structure with regard to its effectiveness in supplying fully functional systems, effective technologies, and efficient services to users
- Reviewed the information systems that support the distribution operations, such as:
  - Transformer load management
  - Trouble reporting system
  - Workforce planning, scheduling, and control
  - Outage reporting
  - Materials management systems
  - Geographic information system (GIS)
  - Automated dispatching

A. Background and Perspective

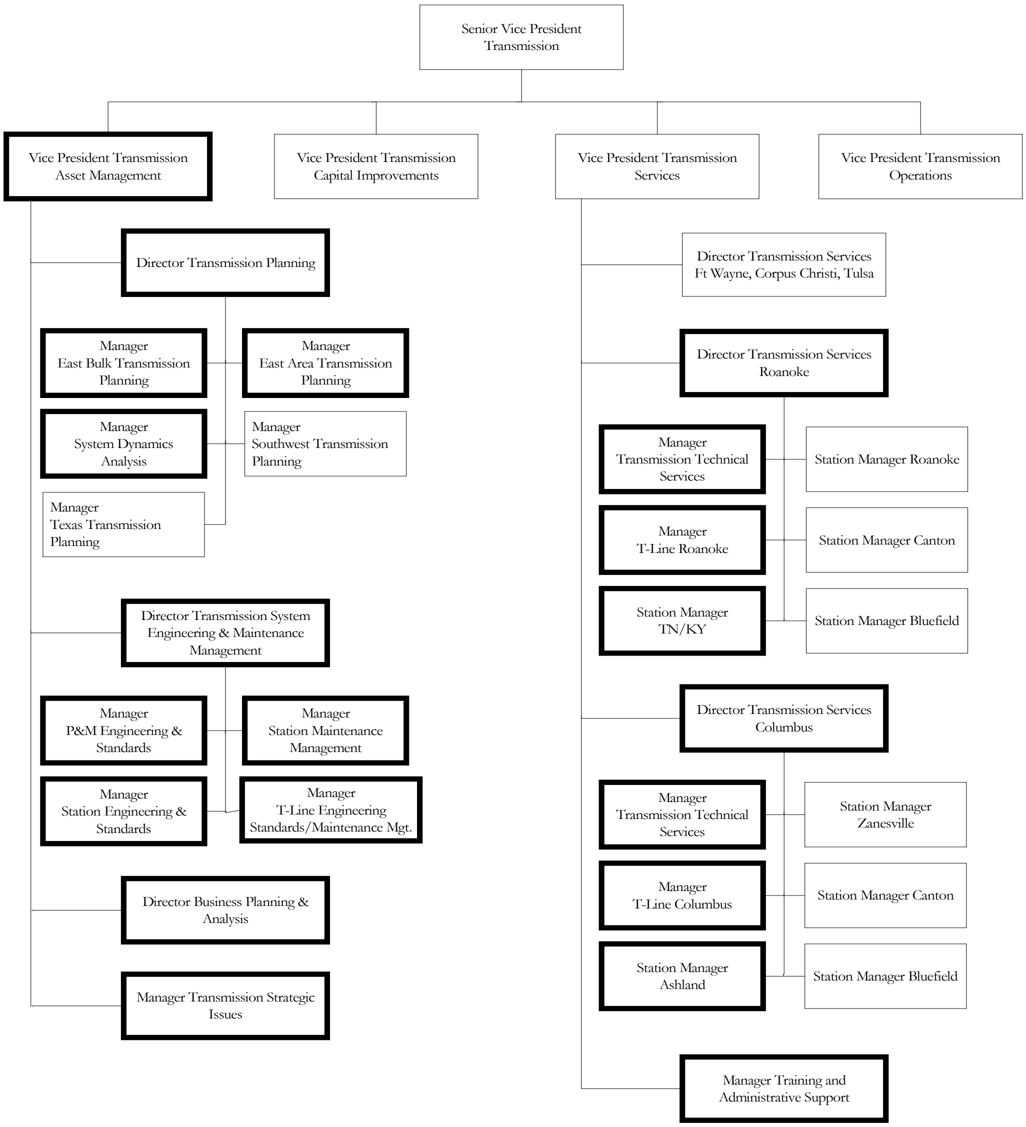
AEP has two organizations in Columbus, OH that are responsible for asset management activities for the whole AEP region (AEP East and AEP West). One group, Transmission Asset Management, is organized as shown in *Exhibit II-1* and the other, Distribution Asset Management, is organized as shown in *Exhibit II-2*.

- AEP has two organizations, with centralized management in Columbus, Ohio that are responsible for the strategic asset management activities. These strategic activities include coordinating and/or developing standard processes, analysis and overall direction of activities related to large scale distribution projects, budgeting & business rules, graphics, joint use, construction & material standards, work management and vegetation management.
- The distribution asset management organization has a significant number of personnel co-located in the regions in the areas of Asset Network & Planning, Asset Data & Application, Asset Standards, Asset Utilization, Work Management and Forestry.
- The regions and Asset Management work in a matrix fashion in the various areas mentioned above for the purpose of continuously improving distribution's performance while balancing with customer needs. Examples of this include changes made in 2002 to the Asset Programs where overall funding in the Charleston region was increased for lightning mitigation, Forestry working closely with the line personnel to prioritize circuit clearing activities, establishment in 2003 of the Sectionalizing Program for the purpose of adding additional circuit sectionalizing devices and improve SAIFI & CAIDI, etc.

Organization and Management

Transmission Asset Management is responsible for transmission assets (69 kV and above in the Hazard Service Area) and all substations, whether they could be considered totally distribution or transmission substations.

Exhibit II-1
Transmission Asset Management Organization

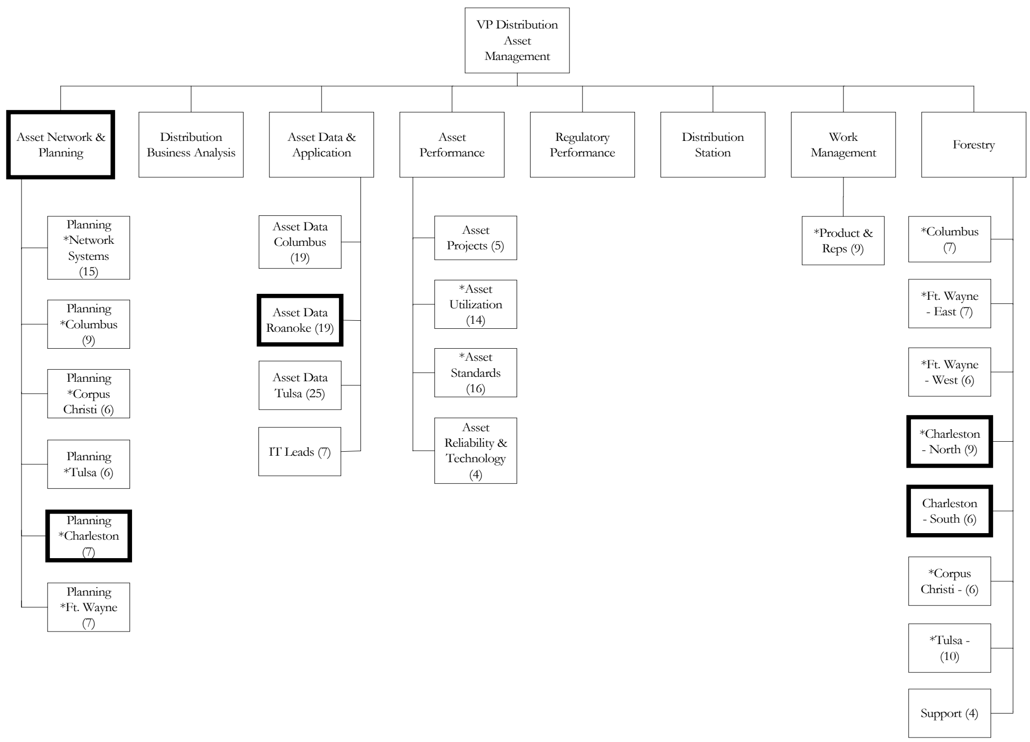


Bold boxes indicate management with most direct accountability for the Hazard Service Area

Although Schumaker & Company reviewed the activities of the Transmission Asset Management organization, it was determined early in our investigations that most of the issues or problems that resulted in our investigations stemmed from issues in distribution, rather than transmission, assets. Transmission assets account for only a small portion of the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) indicators. As a result, our investigations were primarily focused on distribution asset management activities.

Distribution Asset Management, which is responsible for all distribution assets, is organized as shown in *Exhibit II-2*. It is a part of the Distribution organization as shown in *Exhibit II-3*.

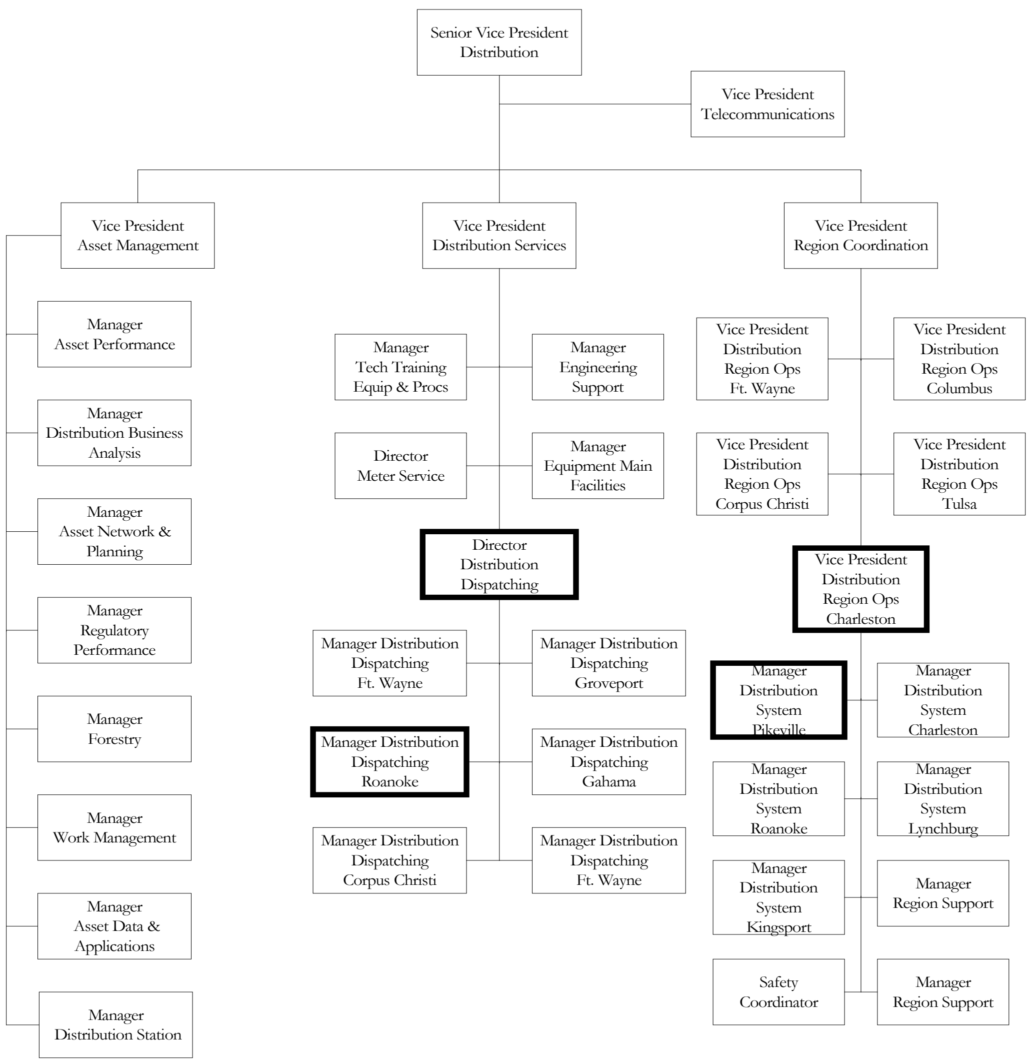
Exhibit II-2
Distribution Asset Management Organization



* Resources located throughout AEP
Bold boxes indicate management with most direct accountability for the Hazard Service Area

AEP/Kentucky is also within the regional organization structure being a part of the Charleston, WV region. Individuals at the region are also charged with asset management responsibilities. In particular the regions, in conjunction with the Asset Management Organization, are responsible for identifying projects within the region that support the overall asset management goals and objectives. The regional organization is shown in *Exhibit II-3*.

Exhibit II-3
Regional Distribution Organization



Asset Planning Engineering performs a formal annual review of the entire distribution system and develops plans for the future. The Regional Engineer works with day-to-day system operations. Asset Planning, which is a centralized operation from an overall point of view, is responsible for providing overall guidance. On a localized basis the Senior Engineer is responsible for his specific assigned area.

Distribution is organized into five regions:

- Charleston, WV
- Columbus, OH
- Fort Wayne, IN
- Tulsa, OK
- Corpus Christi, TX

Each region has a Senior Planning Engineer (an additional Planning Engineers), who reports to the central Asset Management group, responsible for the actual work in their region (day-to-day planning activities). These Regional Engineers develop the details of a proposed project including:

- Project description
- Capital cost
- Cost/benefit analysis

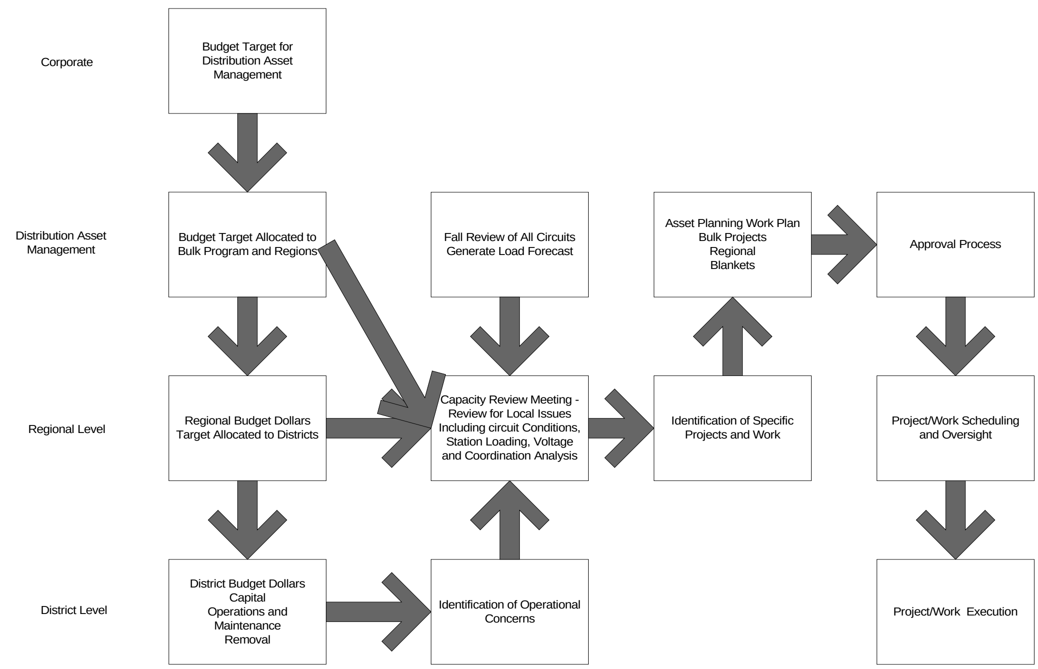
Capital Planning and Budgeting

The overall capital planning and budgeting process is shown graphically in *Exhibit II-4*. The left hand portion of *Exhibit II-4* represents the top-down portion of the capital planning and budgeting process whereas the remaining right hand portion of *Exhibit II-4* identifies how individual projects and work are identified to which these funds are applied. Some of the terms used within AEP include: BCR – Blanket Central Reserve, CPP – Capital Planning Projects, and CIP – Capital Improvement Projects.

The budgeting process is briefly discussed below at the highest level on a step-by-step basis:

- Step 1 – Corporate Planning and Budgeting in the early spring puts out a request for capital project needs from the field organizations. They identify at this point what last year's total budget was and what additional costs will be incurred this year. This is done both for O&M and Capital projects.
- Step 2 – Early indication of the budget in mid- to late-spring
- Step 3 – Distribution Asset Management (for AEP as a whole) splits this preliminary number into several distribution functional buckets, including:
  - Capital projects – includes BCR and CPP projects which are longer-term in nature.
  - VM – Vegetation Management
  - Asset programs (Capital and O&M) – includes CIP

Exhibit II-4
Overall Planning Process



- Central organization funding – to support the AM organization for example
- Various blankets for such items as meters, transformers, etc.

- ♦ Step 4 – A region-based budget which has 5 sub-buckets (for the five regions) that are divided according to historical dollars, customers, line miles, growth, etc. This is the region-based allocation.
- ♦ Step 5 – Final budget – reconciliation.
- ♦ Step 6 – Detailed budget development process
- ♦ Step 7 – State-by-state check for continuity with past spending levels

Over the years the O&M budget tends to be very consistent while the capital budget will vary due to the specific projects that are approved. The factors that go into the decision process to authorize projects include the following:

- ♦ 1 – Capacity – probability of overload

- 2 – Reliability – current performance
- 3 – Customer satisfaction and complaints
- 4 – Environmental risk (where applicable)
- 5 – Safety risk (where applicable)

From a financial standpoint, Asset Management (both distribution and transmission) is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. This budget target is allocated to the bulk program and regions within the Asset Management organization. Each region then allocates these funds to the individual districts within their region.

The technical portion of the overall planning process begins with a review of data in the fall after the summer peak load. This review is undertaken in what is called a Demand Forecasting Meeting, in which various individuals such as Regional Engineers, Technicians, and Servicers meet to discuss issues. Similarly, in the spring, they perform a capacity review at the Capacity Planning Meeting, which results in the projects that are planned for the next 18 months.

Planning much of the bulk work plan of asset management is load-driven based on capacity planning. However, some projects (a small percentage) are driven totally by reliability considerations. According to AEP personnel, they also look at the impacts of improvements on reliability in terms of SAIFI and CAIDI, including the loading on components and estimates of ability to recover from an outage.

The bulk work plan (which is for all of AEP) is used by a central planning group (Distribution Asset Planning) for larger, longer-term projects such as distribution line reconductoring, rebuilds, etc. Generally projects greater than $125,000 are considered large projects and therefore are usually in the bulk work plan handled within Distribution Asset Management, whereas projects under $125,000 are usually handled in the regions. However, recently Distribution Asset Management has begun to include smaller projects, if the projects are forward thinking and improve the system and resolve longer-term issues.

The asset programs are also used for overall reliability programs that have been designed to ensure that ongoing preventative maintenance programs are performed within the regions. These programs include such items as: pole replacements, pole reinforcement, recloser replacement, lightning protection, animal mitigation, URD inspection and replacement, overhead circuit inspection and repair, pole ground-line treatment, and small wire replacement. All of the above categories are divided on a regional basis by program (i.e., transformers, vegetation mitigation, etc.). The regions may not reallocate funds which have been specifically budgeted for these preventative maintenance programs that are considered part of the bulk program (versus the regional budget). The regional budget is generally used for smaller, very reliability-driven projects or for daily repairs and improvements of a more immediate nature. The bulk work plan consists of individual projects that are justified based on specific system needs. The asset programs are targeted at the overall system and are intended to inspect, repair and replace a large number of components (such as poles and wire) for purpose of ensuring safety and the reliability of the system.

The bulk budget is segmented into categories by type of project. The work plan (of projects) for the year is subject to change throughout the year due to new or cancelled projects. Distribution Asset Planning breaks down this lump budgetary number into regional budgets that are based on the priority of the projects (which is apparently developed during the Capacity Review Meetings although Schumaker & Company has no written documentation to support this process) that are projected for each region. The Capacity Review Meetings are where potential projects are discussed. In these meeting planning engineers present areas of system needs and potential project improvements. Various departments participate in these meetings and provide feedback in the presented projects and also discuss alternatives. These departments may also introduce new system needs at this time. The documentation developed from this meeting is the preliminary work plan list. This list includes all potential projects discussed at the Capacity Review Meeting. In the following weeks this list is prioritized based on further project analysis. The final work plan is a ranked list of projects based on project justification (required projects as well as projects based on loading, voltage conditions, area growth, utilization rates, area reliability and contingency recovery).

The 2003 work plan, which was approved in June 2002, included the projects by region and the amount budgeted for those projects. Generally, these projects are for load and capacity at least one year down the road. This process has been in place for approximately two years.

Each of the individual projects in place has an individualized justification developed for it that is called a business case. This is done prior to initiation of the project, but after it has been approved as part of the work plan. Then the project is authorized for undertaking by management. The bases for the business case is developed and documented during the process of evaluating individual projects. It is this justification that determines which projects will be approved as part of the work plan. This documentation is later formalized and submitted with the project for authorization. At that time the project justification is reviewed to ensure the project plan is still appropriate.

Service Reliability

Within the electric utility industry, various methods of measuring electric utility service reliability have been used – from random sample customer surveys to quantitative indicators of service reliability. In brief, service reliability can be measured in two broad areas: hard service reliability indicators and soft service reliability indicators.

Hard Service Reliability Indicators

These reliability indicators are more technically based – based on statistics. Over the years, these indicators have evolved into various indicators. These Reliability Index Calculations were extracted from "IEEE Trial-Use Guide for Power Distribution Reliability Indices" (IEEE Std 1366 – 1998):

System Average Interruption Duration Index (SAIDI) – The average service interruption duration, measured on a system-wide basis. SAIDI equals the sum of all customer interruption durations divided by the total number of customers the utility serves during the reporting period.

$$\frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customers Served}} = \frac{\sum r_i N_i}{N_T}$$

Comment [ACE1]:

System Average Interruption Frequency Index (SAIFI) – The average number of sustained outages per customer per year. SAIFI equals the total number of customer outages divided by the total number of customers the utility services during the reporting period.

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}} = \frac{\sum N_i}{N_T}$$

Customer Average Interruption Duration Index (CAIDI) – The average time required to restore service to an average customer per sustained interruption. CAIDI equals the sum of all customer interruption durations divided by the total number of customer interruptions.

$$\frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}} = \frac{\sum r_i N_i}{\sum N_i}$$

Where the values of the parameters in the above equations are as follows:

- i = An interruption event
- r_i = Restoration time for each interruption event
- T = Total
- ID_E = Number of interrupting device events
- N_i = Number of interrupted customers for each interruption event during the reporting period
- N_T = Total number of customers served for the area being indexed

Soft Service Reliability Indicators

Years ago, when electric utilities began to conduct customer surveys in an attempt to determine what "hard" service reliability was acceptable to customers, it was discovered that "soft" reliability indicators were perhaps just as important, if not more so, than "hard" indicators. Specifically the customer was more interested in being kept informed in the event of an outage than in some engineering based performance index. In short, if in the event of an outage the customer calls the call center and simple questions cannot be answered, customer satisfaction levels decrease. Examples of such simple questions include:

- What caused the outage? i.e., does the utility know what is going on?
- How soon will my power be restored? i.e., do I need to do something immediately to minimize the impact of the outage?

As a result, it is recognized within the electric utility industry that it is not just enough to concentrate on "hard" service indicators. Business processes and systems need to be developed that can also keep the customer informed throughout the outage restoration process.

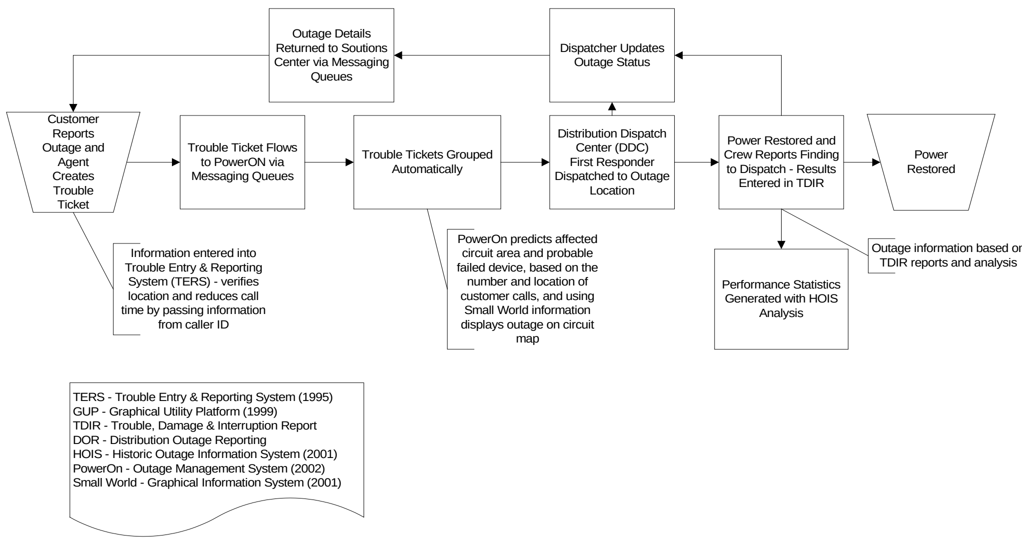
B. Findings and Conclusions

Finding II-1 Technology systems have been significantly upgraded in the last five years.

Outages are inevitable. It would be all but impossible to cost effectively design an electric network to prevent an outage from occurring. Therefore it is important that the "customer experience" from an inevitable outage be as painless and managed as economically as possible.

Over the last five years, AEP has made significant upgrades in their technology and systems that are involved in responding to customer outages and reporting on the progress of outage restoration. The specific systems that are involved in the area of asset management are shown in *Exhibit II-5*.

Exhibit II-5
Key Technology Systems Effecting Reliability



The identification of an outage usually begins with a customer calling the AEP Solutions Center (call center). The Solutions Center agent enters the information into the Trouble Entry & Reporting system (TERS). TERS is an internally developed system implemented around 1995, that collects information on the outage and also supports the ongoing reporting of progress on outage restoration such that information can be relayed to the customer if they call in again or if additional customers affected by the same outage call in.

That trouble ticket then flows to the PowerOn software. The trouble tickets generated as the result of an outage are grouped and analyzed by PowerOn, and a failed device (transformer, fuse, breaker, etc.) is "predicted." PowerOn "predicts" the affected circuit area and probable failed device based on the number and location of the customer calls. All of this information can be displayed on geographic maps, via an interface to the Small World system that was implemented in the last several years, in the Distribution Dispatch Center (DDC) in Roanoke, VA. This information on the "predicted" failed device can be relayed to the Servicer that is dispatched to identify and repair the outage cause. PowerOn is a purchased software package that was implemented in the last year (2002) in AEP/Kentucky.

Dispatchers in the DDC contact a Servicer within the affected area (county in the Hazard Service Area) to diagnose the outage at the circuit. Dispatchers remain in contact with the Servicer throughout the outage and are able to input status information into TERS such that customers can be informed of the status as needed. Once the outage is corrected, information is collected and summarized on a Trouble, Damage & Interruption Report that is then reviewed and entered into the Historical Outage Information System (HOIS). HOIS is an Oracle database that was implemented in 2001 to replace the previous Distribution Outage Reporting (DOR) system. HOIS supports various forms of reporting on historical results.

Throughout the above process, dispatchers can input status information into the TERS system such that the status information is available to relay to customers when they call in, to either report the same outage or inquire as to the status of the outage. Customer surveys have shown that the ability to keep the customer informed is one of the key capabilities that customers want during outages. Throughout the management of the outage, AEP/Kentucky has the ability to keep the customers informed.

Finding II-2 Call center operations for trouble reporting appear appropriate.

All initial customer calls on outages are handled in call centers, collectively called the Solutions Center. The AEP Solutions Center is currently organized into an East and West configuration. AEP is evolving toward a national virtual call center configuration, once the back office systems are capable of supporting such an operation, where a customer call that originates anywhere in the AEP service territory could be handled at any Solution Center location. The East is currently a virtual call center – that is any customer call can be answered by any of the following Solutions Center locations:

- Groveport with 150 to 180 total employees of all job classifications
- Fort Wayne with 60 to 80 total employees of all job classifications
- Hurricane, WV with 200 total employees of all job classifications
- Ashland, KY (will be phased out by the end of the 2002)

Common back office systems have been implemented throughout the East such that the virtual call center could be created. This virtual call center configuration allows AEP to handle more calls in the event of an emergency. There are two approaches used with virtual call center:

- Pre-call routing – All calls go to anyone
- Post-call routing – Used by AEP, where each customer has an assigned Home Center Site, which for AEP/Kentucky is Hurricane, WV; if there is no service representative available at Hurricane, the call can be routed to an available representative in another Solutions Center. As a result, a percentage of the calls received at a given Home Center site will be from a different area.

AEP targets a 60 second average speed of answer (ASA). Since they started virtual call routing in 1997, they have consistently achieved this goal. AEP attempts to route all calls to an agent. If agents are available at the home site, the caller is not requested to indicate the type of inquiry and is routed directly to an agent for processing. If all agents are busy at the home site, the caller is prompted for the type of call. The prompts include the ability for customers to be routed to the IVR for processing. The prompting is only four levels deep to minimize the confusion of the customer.

Although AEP's overall goal is to have all calls answered by a service representative instead of an automated system, such as an IVR system, AEP uses a third party application, which has a high capacity IVR system for customers to report the outages at the outset of a storm before the virtual call center has been ramped up. This reduces the number of customers that may receive a busy signal. The overflow system is activated to reduce the number of busy signals customers receive and is deactivated once the outage has been restored. When AEP activates the external IVR, it can control the number of calls that will go to the Solutions Center based on the geographic location of the caller. The geographical redirection of the caller is based on the area code and exchange of the calling party. This functionality reduces the number of non-outage callers that would be routed to the third party outage application in error. If the external service is activated, a portion of calls continues to be routed to the Hurricane Solution Center which could be answered locally or at another AEP solution center as described above. Calls not routed to the Hurricane Solution Center are routed to the third party application where customers can interactively report their power outage. AEP also has Internet-based outage reporting and service order capability. Outages are being reported on the Internet.

The Solutions Center is full service 7x24 for all customers. However, not all Solutions Center locations are open 7x24. Groveport and Hurricane are open 7x24, while Fort Wayne is open fewer hours. Most of the service representatives are full-time; however some are part-time (20 hours per week) and are used for load shaving purposes – i.e., they need them to work to handle large load periods. Turnover is approximately 21% per year – low for a call center environment. Service representatives do not have verbatim scripts – they have bullet items. The Solutions Center management records random callers and evaluates them based on rates involving caring, concern, grammar, tone, etc.

The call center work group organization is structured as follows:

- Manager
- Group Supervisor
- Team Lead
- Customer Service Associates

A work group is composed of anywhere from 16 to 18 agents (Customer Service Associates).

Although the Quality and Training Support group does live call monitoring, most of the live monitoring is done by Supervisors and Team Leads. Also the Manager and Director do spot live call sampling. Therefore, numerous opportunities for live monitoring exist. AEP has vendors who do third-party customer satisfaction surveys. AEP also has a complaint tracking mechanism to monitor complaints.

A call is only considered a complaint if AEP has had a prior opportunity to resolve the situation. Complaints would come in through the Solutions Center. The Customer Service Associate makes the determination as to whether a call is a report, inquiry, or complaint based mainly on the content of the call and the tone and level of agitation of the caller. The Solutions Center will try to handle the problem, but if the customer is still not satisfied, it will be escalated to a manager or higher, if necessary. Most calls that are escalated to a manager are classified as complaints. If the customer cannot be satisfied by the Customer Service Associate then the call would be considered as a complaint.

Finding II-3 Asset Management manages several different reliability programs that specifically address the hardware aspects of reliability.

Within the Asset Management organization various reliability programs exist that have been designed to ensure that certain ongoing preventative maintenance activities are performed. These programs include such things as:

- Pole replacement
- Pole reinforcement
- Recloser replacement
- Lightning protection
- Animal mitigation
- URD inspection and replacement
- Overhead circuit inspection and repair
- Pole ground-line treatment
- Small wire replacement
- Sectionalizing program (implemented after this report was drafted)

All of the above categories are divided on a regional basis by program (i.e., transformers, vegetation mitigation, etc.).

Capital and operations and maintenance funds are budgeted to each region for the above programs within the Distribution Asset Management organization based on prior year's expenditures and discussions with field personnel. The regions are allowed to reallocate money from any of these categories into other areas. The need to reallocate funds from one asset program to another is determined by a joint decision making process between the region and asset management at mid year which accounts for changes in projections such as pole inspection results, circuit inspection results, etc.. There is an exchange of information both up and down to complete the process as discussed previously. As yet, AEP/Kentucky does not have the capability of forecasting the impact of these expenditures on the changes in SAIFI. However, AEP has developed several models to attempt to quantify the impact of changes in expenditures on SAIFI performance. However, it will require several years of analyzing actual field results to validate the models.

Finding II-4 The budgeting process is predominately a top-down process.

Asset Management is given a budget target for both transmission and distribution expenditures, which are developed by corporate based on the prior year's budget – with modifications for known savings or expenses that would be incremental in the next year. These budgeted amounts are initially divided among the Asset Management groups and the regions by the Asset Management organization. Overall distribution budgets are allocated to regions based on line miles, customer counts and customer growth. The bulk work plan budget allocation is separate and independent of the region budget.

As such, budgets are not necessarily requirements based. Budgets are based more on prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. This approach results in a setting of budgets such that field personnel are only left with deciding how "best" to spend the dollars. To put this in another context, if in *Exhibit II-4* the top down budget allowances are such that any bottoms-up projects identified by the districts cannot be included in the final budgets, it provides little incentive for district managers to push hard for projects that are known by them to be beneficial to the customers for reliability or other reasons. The key aspect of this whole process is the interaction that takes place in the Demand Forecasting Meetings and how projects are included within the final budgets. AEP/Kentucky has been unable to provide much written documentation (projects identified, project included, projects deferred, by year by budget) concerning this process and interaction.

Distribution Asset Management

Distribution Asset Management is given a budget target (capital, operations and maintenance, and removal) for distribution, which is developed by corporate based on the prior year's budget with modifications for known savings or expenses that would be incremental in the next year. Asset Management allocates these budget dollars to the bulk budget (typically projects greater than $125,000 and the preventative maintenance budgets or reliability programs) and regional budgets. The regional budget is used for customer service, service restoration, labor associated with asset programs, minor assets improvements, and highway relocation and therefore is divided into those categories. This regional budget is divided down to the Pikeville District level by the above categories.

Dollars are actually charged and budgeted to three categories:

- Capital
- Operations and maintenance (O&M)
- Removal (small $ amount for pole removal, for example)

A large allocation ($3 million to $4 million) requires a Capital Allocation Proposal that includes a description of the project and details of the cost/benefit analysis. There are various levels of signoffs depending on the size of the project. Projects of $125,000 to $750,000 are funded under blanket allocation dollars and come out of the Asset Management budget. Projects of less than $125,000 are funded from either Distribution Asset Planning's or the region's budget. They are usually covered in what are called blanket budget accounts. Blanket budget accounts are created to handle many smaller projects. These can be done with only local approval under the blanket budget account. These total blankets are approved by the AEP Board, but local authorization to perform the project is acceptable.

Creating a budget does not authorize any expenditure of funds. Rather the projects must be authorized on an individual basis at some management level depending on their size.

Transmission Asset Management

Transmission Asset Management is given a budget target for transmission, which is developed by corporate based on the prior year's budget with modifications for known savings or expenses that would be incremental in the next year. Transmission asset management then aligns its projects to use the budget for the year. There are two groups that share the transmission budget allocation dollars:

- Capital projects
- Rehab projects

Transmission capital budget expenditures have been relatively stable over the past 3 to 5 years; however, the following two other categories can vary widely:

- Independent power producer connections
- Special projects (very large specialized projects)

Finding II-5 AEP/Kentucky was unable to readily provide historical information regarding planning and budgeting processes.

According to AEP/Kentucky, much of the decision making regarding projects takes place in the Capacity Review Meetings where potential projects are discussed. Various departments participate in these meetings and provide feedback in the presented projects and also discuss alternatives. The documentation developed from this meeting is the preliminary work plan list. This list includes all potential projects discussed at the Capacity Review Meeting. However, AEP/Kentucky was unable to provide us with these historical lists. Additionally, a request for the three prior year's transmission and distribution operations and maintenance and capital budgets was also difficult for AEP/Kentucky to develop. AEP/Kentucky had under gone a change in accounting systems during this time period which made it difficult for this information to be obtained.

Finding II-6 The capital and operations and maintenance budgeting processes by which funds were allocated to the Hazard Service Area have not resulted in improvements in reliability indicators or prevented extended outages.

As previously discussed, capital and operations and maintenance budgets are based primarily on the prior year's expenditures, corporate goals, and other items that do not necessarily relate to what needs to be spent to provide improvements in service quality. Capital and operations and maintenance expenditures for AEP/Kentucky have decreased significantly from 1999 as shown in *Exhibit II-6*. In essence, distribution capital and operations and maintenance expenditures are at almost the same level in 2001 as in 1996.

As shown in *Exhibit II-7*, the Buckhorn Area Improvement project, at $496,100, was a very significant project for the Hazard Service Area. It was by far the largest single project within the Hazard Service Area in the 2000-2002 timeframe. Schumaker & Company consultants were told that the Buckhorn area had been known to be a problem, i.e. it was not a surprise, and that it had been in the plan for several years, but was relegated to a future timeframe. Although it is difficult to determine the validity of these statements due to a lack of written historic documentation, it is understandable that it would not probably have been politically expeditious for Hazard Service Area personnel recommend a project the size of the Buckhorn Area Improvement during a time when funds were being constrained at the corporate level. Simply put, a $496,100 project in a $38 million total budget for AEP/Kentucky (our approximately $1 million for the Hazard Service Area) would probably have required significant justification on the grounds of improved reliability, cost and benefits, etc.

As is discussed in *Finding II-7*, AEP/Kentucky has only recently begun to tie some of its reliability programs to improvements in SAIFI, CAIDI, and SAIDI. Therefore, the tools to support the business justification of projects such as the Buckhorn Area Improvement did not exist within the Hazard Service Area let alone AEP/Kentucky. Without such tools, it is difficult for District management to be able to quantitatively justify large capital and operations and maintenance expenditures. However it should be understood that the funds were redirected once the affected customers complained to the Kentucky Public Service Commission.

Exhibit II-6
Transmission and Distribution Expenditures (1996-2001)

Transmission and Distribution	1996	1997	1998	1999	2000	2001
Distribution						
Capital	$21,549,800	$23,159,084	$17,987,868	$26,115,738	$22,558,353	$21,071,480
O&M	$16,453,642	$17,827,814	$21,633,952	$22,763,501	$17,052,323	$17,248,292
Total Distribution	$38,003,442	$40,986,898	$39,621,820	$48,879,239	$39,610,676	$38,319,772
Transmission						
Capital	$2,964,048	$40,973,981	$23,872,816	$29,359,675	$5,892,833	$13,686,830
O&M	$4,777,758	$4,424,148	$4,753,922	$3,543,039	$5,377,526	$4,973,664
Total Transmission	$7,741,806	$45,398,129	$28,626,738	$32,902,714	$11,270,359	$18,660,494
Total T & D	**$45,745,248**	**$86,385,027**	**$68,248,558**	**$81,781,953**	**$50,881,035**	**$56,980,266**

The Distribution capital expenditures for 1998 and 1999 are accurate from an accounting perspective, but not when the money was actually spent for work being performed. Due to the implementation of a new financial software release, People Soft 7.0 across AEP, during the 4th quarter of 1998. Any work orders that would have been closed during the 4th quarter were not closed until 1999. This results in a lower amount of capital being placed on the property records in the 1998 and a higher amount in 1999. This is shown as a 25% lower than average spending in 1998 and a 25% higher than average spending in 1999. The actual capital spending for 1998 and 1999 are closer to the average of these two years.

The primary reliability projects and related costs for the Hazard Service Area for the last several years are shown in *Exhibit II-7*.

Exhibit II-7
HSA Reliability Projects and Related Costs

	Operating Area	Costs	Year Approved
System Improvement			
Whitesburg Area Sectionalizing	Whitesburg	$82,063	2000
Bonnyman-Hazard Circuit Improvements	Hazard	$100,300	2002
Buckhorn Area Improvements	Hazard	$496,100	2002
Total System Improvement		$678,463	
Distribution Inspection and Maintenance			
Distribution Pole Replacements	Whitesburg and Hazard	$624,958	2000-2002
Distribution Reclosure Replacements	Whitesburg and Hazard	$777,197	2000-2002
Distribution Animal Guards Installments	Whitesburg and Hazard	$19,008	2000-2002
Distribution Reinforcements	Whitesburg and Hazard	$132,308	2000-2002
Lighting Arrestors	Whitesburg and Hazard	$7,227	2000-2002
Overhead Circuit Inspection	Whitesburg and Hazard	$327,771	2000-2002
Total Inspection and Maintenance		$1,888,469	
Vegetation Management	Whitesburg and Hazard	$4,033,202	2000-2002
Total		$6,600,134	

Despite the above referenced investments, the SAIFI, CAIDI, and SAIDI numbers, as shown in *Exhibit II-8* thru *Exhibit II-10*, have varied little over the last six years with the SAIFI and SAIDI numbers trending slightly down but CAIDI remaining relatively unchanged. In almost all cases, the Hazard Service Area has the highest (worst) results within AEP/Kentucky.

Exhibit II-8
SAIFI (Excluding Storms) Results for AEP/Kentucky

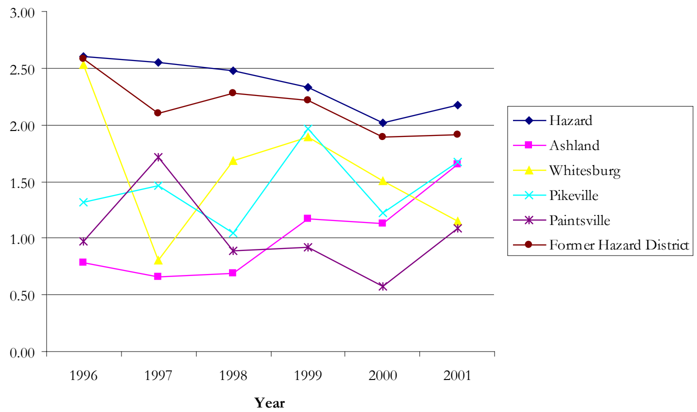


Exhibit II-9
SAIDI (Excluding Storms) Results for AEP/Kentucky

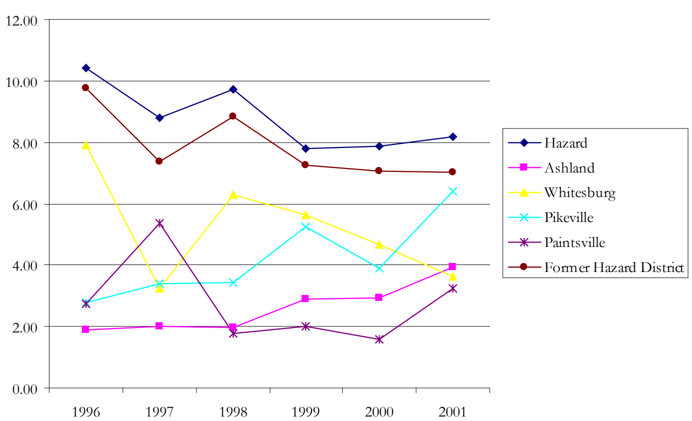
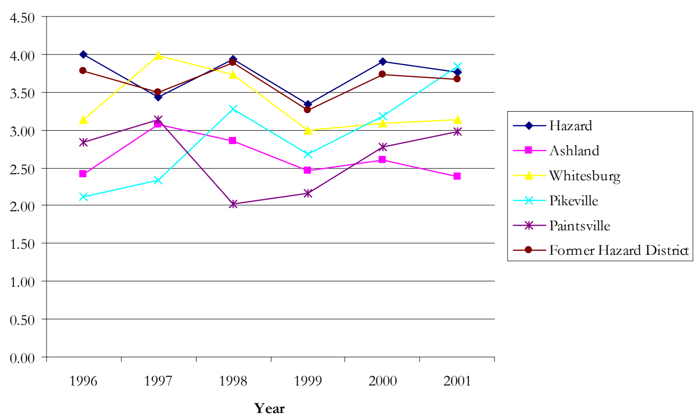


Exhibit II-10
CAIDI (Excluding Storms) Results for AEP/Kentucky



These numbers will probably appear worse in the future due to a change in the method of reporting these results (via the new Outage Management System).

Finding II-7 Reliability programs are not specifically designed to make specific improvements in SAIFI, CAIDI, and SAIDI by targeting improvement in frequency, duration, or number of customers.

AEP/Kentucky has attempted to tie some of its reliability programs into improvements in SAIFI. In particular, a model has been developed based on theoretical assumptions that will require several years of analyzing actual field results to validate the model. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality.

AEP/Kentucky internal studies have also identified the need for more proactive outage and circuit review and improvement projects for circuits with poor service reliability. AEP/Kentucky management recognizes that opportunities exist for reducing response times, improving restoration work practices, vegetation management, and further automating stations and systems with Supervisory Control and Data Acquisition (SCADA) systems. Some of the changes that have been made as a result of these internal studies include the Three Times Outage Report, which shows each isolating device that has locked out three times or more in the past twelve months. This information is used to eliminate the reoccurring outages that have affected customers most frequently. Examples of the proactive work that was targeted to improve the reliability of poor performing circuits are as follows:

- The Three Times Outage Report captures any primary voltage sectionalizing device that has experienced three or more sustained outages in a rolling twelve-month period; the appropriate Regional Engineer or Forestry Specialist is responsible for initiating actions designed to prevent future outages at each device
- Sorting of the area distribution circuits by SAIFI/CAIDI to create a worst performer list to provide first steps in identifying opportunities to improve the reliability of those circuits; examples of work that were performed include targeted widening of the right-of-way in the circuit breaker protection zone, installing fused cutouts on unprotected side taps, and upgrading the overall circuit sectionalizing schemes
- Review of station breaker operations by reports derived from the Integrated Substation Information System (ISIS) to identify circuits that may have right-of-way issues in the circuit breaker protection zone ISIS is a record system that includes operation counts of circuit breakers inside the substation. These counter readings are obtained during scheduled substation inspections. For distribution circuits, the history of main circuit breaker operations can be reviewed (an unusually high number of operations) as an indicator of circuit problems within the breaker's protective zone. The causes of these operations would not be limited to trees and the circuit would be investigated for any obvious problems, including trees.
- Tracking of devices in the abnormal equipment database to initiate actions to return equipment to service
- A region-wide spreadsheet database of reliability related projects that are prioritized so the best projects can be completed, as funding is made available; this list can also be used to solicit funding from Asset Planning to obtain resources from outside the region/district base budgets
- A just-completed 2003 right-of-way (ROW) maintenance plan for each operating area that was created through cooperation among local line supervision, regional engineering, and forestry personnel to target the worst performing circuits
- A review of potentially overloaded primary stepdown transformers, the purpose of which is to prevent outages caused by transformer failures during the upcoming winter heating season
- A review of the region's most unbalanced circuits on an amps/phase basis at the circuit breaker; the purpose of this effort is to improve the load balancing on the region's more heavily loaded station transformer banks and reduce the possibility of premature transformer failure.

The ability to tie the reliability programs into performance improvements in SAIFI, CAIDI, and SAIDI is highly dependent on having the performance data to analyze. Much of this performance data is available from the management and information systems that were discussed in *Finding II-1*. This data will need to be "mined" to makes this capability a reality. An example of the type of analysis that AEP/Kentucky should be undertaking with this information is presented in *Finding II-8*.

Finding II-8 Field crew staffing levels need to be approached from a response effectiveness analysis.

Hazard Service Area staffing has been significantly reduced over the last five years as shown in *Exhibit II-11*.

Exhibit II-11
Hazard Service Area Staffing Changes 1997 to 2001

Employee Group	End 1997	End 2001	Percentage Reduction
Supervisors Distribution Service	1	1	0%
Line Crew Supervisors	9	8	11%
Distribution Line	36	22	39%
Stores	4	4	0%
Customer Services, Billing & Collections, Meter Reading	25	13	48%
Marketing/Key Accounts	5	2	60%
Transmission/Station	9	1	89%
Metering	2	2	0%
Building Maintenance	3	1	66%
Fleet	4	2	50%
Communication	1	1	0%
Engineering/Technicians	12	8	33%
Community Service Manager	0	1	N/A
Total	111	66	41%

Although AEP/Kentucky has made many changes in the last five years that could support some of the reduction in numbers shown in *Exhibit II-11*, such as the introduction of new computer systems, the most sensitive area with respect to system reliability is the Distribution Line area. One of the primary roles of Distribution Line personnel is to respond to outages. It has become even more important as response staff has been decreased.

In particular, the first responder to an outage in AEP/Kentucky is a Servicer. As discussed later in this report, Servicers in the Hazard/Whitesburg area are currently working significant levels of overtime. Furthermore, according to AEP personnel, Servicers are able to completely handle (restore) service 75% of the time without having to call out other support – line crew personnel. Therefore the Servicer position is a key position relative to the impact on overall performance indicators, specifically CAIDI.

Electric utilities cannot directly "manage" SAIDI, SAIFI, and CAIDI. However, electric utilities can manage the individual parameters that go into making up these numbers. Specifically each of these indicators is a function of just three items:

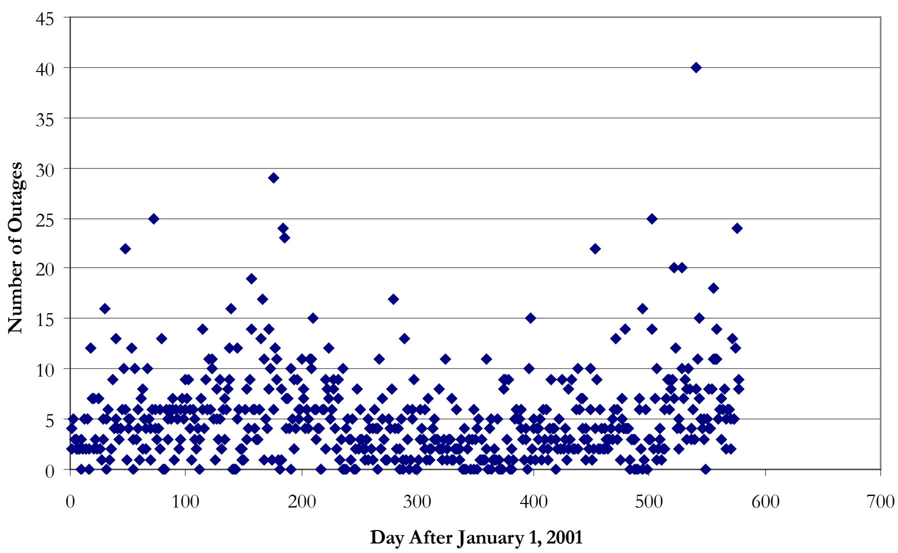
SAIFI
SAIDI = Function (frequency, duration, number of customers)
CAIDI

- ***Frequency*** – frequency of occurrence
- ***Duration*** – how long it takes to restore the outage
- ***Number of customers*** – how many customers are affected by the outage

The important thing to take away from this function is that Servicers impact duration. If there are too few Servicers, then when multiple outages occur, the outages get stacked in a queue (the Servicer can only work on one outage at a time and the extra outages have to wait until the current one is restored), resulting in longer durations. There are also geographic challenges in the Hazard Service Area – such as long travel time to site, lack of river crossings or direct routes, etc. Additional Servicers could help lessen the impact of these factors.

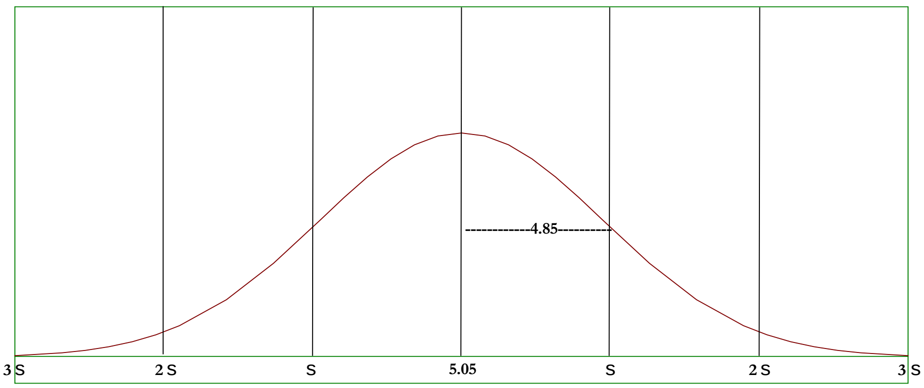
For a simple example of the type of analysis that could be done with the data that AEP/Kentucky already has available, outage information was obtained for the Hazard/Whitesburg area for the time period January 1, 2001 to August 1, 2002 (578 days). This information was analyzed by Schumaker & Company to create a representation of the number of outages that occur on any given day. The results are shown in the scatter diagram in *Exhibit II-12*.

Exhibit II-12
Number of Outages per Day



For illustrative purposes, if we assume that the above information is normally distributed, then it could be represented by a bell shaped curve as shown in *Exhibit II-13*, with an average of 5.05 and a standard deviation of 4.58. Translating these numbers into a more useful insight, a median of 5 means that for half the days in the year there are approximately 5 or fewer outages in the Hazard/Whitesburg area and for half the days there are more than 5 outages.

Exhibit II-13
Normal Distribution of Outages per Day



Furthermore, we know from a normal distribution that one standard deviation from the average contains 68.2% of the occurrences. From a more practical viewpoint, 84.15% of the time the Hazard/Whitesburg area experiences less than 10 outages in a day, as shown in *Exhibit II-14*.

Exhibit II-14
Normal Distribution Percentages

Standard Deviation from the Mean	Area Within Standard Deviation	Area in Upper and Lower Tails	Area to the Left of Right Standard Deviation
1	68.2%	31.7%	84.15%
2	95.4%	4.5%	97.75%
3	99.7%	.2%	99.99%

The fundamental question that needs to be decided is where on this distribution does the utility staff its field force level to cost effectively minimize the impact of the right hand side of the normal distribution curve to minimize CAIDI.

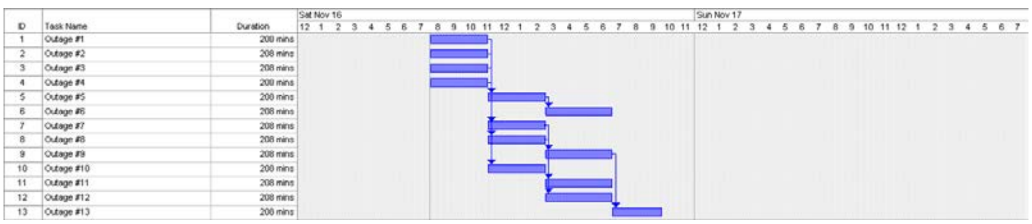
It can also be determined from the same information that the average restoration times are as shown in *Exhibit II-15*. As *Exhibit II-15* illustrates, restoration times are shorter on 34.5 kV/19.92 kV circuits as compared to 12.47 kV/7.2 kV circuits. It might be expected that on average 66 customers are out of service on 34.5 kV/19.92 kV circuits compared to 47 customers on 12.47 kV/7.2 kV circuits. Most likely, Servicers are being dispatched to 34.5 kV/19.92 kV circuits before 12.47 kV/7.2 kV circuits due to the higher customer counts.

Exhibit II-15
Outage Response Times

Distribution Voltage	Average Number of Customers Impacted	Average Number of Customer Minutes Out
34.5/19.92 kV	66.35	208.63
12.47/7.2 kV	46.95	254.41

Outages are not necessarily evenly spaced throughout the day. In particular, it is most likely on days that experience a higher number of outages that there is a precipitating event – i.e., thunderstorm, snow storm, or ice storm, etc. In those cases, the outages would most likely occur around the same time. This timing could lead to a stacking up of outages such that some outages would have to wait to be dispatched until a Servicer is released from another outage as illustrated in *Exhibit II-16*.

Exhibit II-16
Outage Response Scenarios



This finding and example illustrate how some of the information currently being collected could be used to begin to establish staffing levels from the bottom up. There are several other items that would need to be investigated and incorporated into the analysis before this "ground up" analysis would be complete. These items could also include:

- Goal on the distribution curve for designing staffing response – i.e., a 50%, 80%, etc., service level target
- Outage distribution by time of day
- Effective Servicer availabilities (incorporation of the impact of vacation and sickness, Servicers on disability, linemen serving as Servicers etc. into the actual Servicer availability on any given day, and callout turndown rates for each Servicer)

Finding II-9 Outages results are getting worse.

The results within the Hazard/Whitesburg area are shown in *Exhibit II-17* in terms of number of customers impacted and customer minutes.

Exhibit II-17
Outage Results

Timeframe	Number of Customers	Total Customer Minutes
January to July 2001	57,271	13,215,155
January to July 2002	88,882	18,463,101
Increase Over Prior Period	55%	40%
January to December 2001	86,297	20,128,592

The total number of customers impacted from January to July of 2001 compared to 2002 has increased by 55% and the customer minutes by 40%. Some of this increase might be explained by more accurate reporting as a result of the improved systems (specifically PowerOn and HOIS). However, to the extent that this increase is not a result of improved reporting, it could be indicating that service levels are getting worse.

Finding II-10 More analysis is needed of the data that is currently being collected from new systems to improve reliability.

SAIFI, SAIDI, and CAIDI are industry recognized ways of measuring electric system reliability. Each of these indexes requires that an outage be "identified" before it can be measured. This "identification" process to a large part depends on the customer calling AEP/Kentucky to report an outage – unless the outage causes a remotely monitored protection device to activate and lock out.

However, customers are also affected by momentary outages. Momentary outages are defined as outages that last less than five minutes. In many cases, these outages are self correcting – the tree branch that contacts the circuit is no longer in contact and the protection device resets, etc. It is difficult for utilities to measure these outages, because in many cases they occur and correct without the utility even being aware. However, more customers are now very aware of the impact of these outages by the flashing digital clocks that require resetting. In fact, customers can record these outages on their own to begin to develop a stronger case regarding unacceptable service quality from their utility. In essence, the customer could develop the data to show problems in service quality when the utility would have no information from which to refute the information.

The Institute of Electrical and Electronic Engineers (IEEE) has an indicator that attempts to measure the impact of these momentary outages. It is called MAIFIE or Momentary Average Interruption Event Frequency Index (Momentary Events) and is defined as shown below:

$$\frac{\text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} = \frac{\sum ID_E N_i}{N_T}$$

However, without special equipment, this index is difficult to measure in that the data acquisition part is expensive – you have to have some way of knowing that a momentary outage occurred.

C. Recommendations

Recommendation II-1 **Develop a more appropriate approach to determining capital and operations and maintenance funding levels (Refer to *Finding II-4*, *Finding II-6*, and *Finding II-7*).**

At the current time, asset management decisions are driven primarily by load growth and the available capital and O&M funds. The available funds have been allocated based on a top-down development of the budget, with the Asset Management groups and regional personnel making the decisions on how to best use those funds. However, complete listings of annual work loads or field requirements have not been developed for the Whitesburg/Hazard area. These forecast workloads would include the results of proactive outage and circuit reviews for circuits with poor service reliability, tree inventories for all circuits, and complete inventories for all other reliability items currently being performed (pole replacements, small wire, etc.). It is this forecast workload data that would form the basis for the development of comprehensive bottom-up capital and O&M requirements. In the past year, AEP/Kentucky has begun to develop some of the information required for a bottom-up approach through the Three Times Outage Report and other items mentioned in *Finding II-7*.

This bottom-up workload forecast quantification would then need to be balanced against the top-down funding levels to identify shortfalls in the funding required to support the target level of service quality that is to be provided in the Whitesburg/Hazard area. Shortfalls would then need to be recognized as either workload that will need to be deferred (it does not go away, but most likely accumulates exponentially over time) or for which alternative sources of funding will be required – most likely through the regulatory process.

Recommendation II-2 **Each circuit within the Hazard Service Area should be analyzed and a reliability improvement plan developed. (Refer to *Finding II-6* and *Finding II-7*).**

As mentioned in *Finding II-6*, it was difficult to determine the extent to which the individual circuits within the Hazard Service Area had been analyzed relative to any of the following reliability issues:

- Outages (SAIDI, SAIFI, and CAIDI)
- Momentary outages (which are not reflected in any indicator at this time)

- Cold load pickup (the ability to reenergize a complete circuit instead of having to step the circuit back into service)
- The current status of vegetation along the circuit
- The condition of equipment

During the course of the project, Schumaker & Company consultants did perform a brief design review of several circuits to identify any obvious issues with specific circuits. However, it is our expectation that a formal written design review of all HSA circuits would be performed and updated on an annual basis. AEP/Kentucky had performed some aspects of such a review in the past in response to KPSC concerns, but we did not find evidence that all circuits had been reviewed in such a manner – as evidenced by the Buckhorn situation. A complete review of all circuits within the HSA needs to be performed and updated on an annual basis. This review should result in a written work product that can be reviewed by KPSC staff.

Recommendation II-3 Maintain historical information on operations and maintenance and capital planning processes. (Refer to *Finding II-5*).

AEP/Kentucky needs to maintain historical information on operations and maintenance and capital planning processes such that this information can be provided to the Kentucky Public Service Commission and the effectiveness of the planning processes can be measured.

Recommendation II-4 Develop a methodology for specifically tying capital and operations and maintenance investments to reliability indicators (Refer to *Finding II-6* and *Finding II-7*).

As mentioned in *Finding II-7*, AEP/Kentucky has attempted to tie some of its reliability programs to improvements in SAIFI. However, this model does not address SAIDI or CAIDI considerations. There is more that needs to be done within AEP/Kentucky to begin to tie the result of its reliability programs into improvements in service quality. The ability to tie the reliability programs into performance improvements in SAIFI, CAIDI, and SAIDI is highly dependent on having the appropriate performance data to analyze. Much of this performance data is available from the management and information systems that were discussed in *Finding II-1*. This data will need to be "mined" to makes this capability a reality.

Recommendation II-5 Use statistical methods for establishing field force staffing levels (Refer to *Finding II-8*).

One of the primary roles of field forces is to respond to outages. Field force levels have been reduced throughout the electric utility industry as a result of a combination of factors but, specifically:

- A reduction in major new construction projects
- A greater reliance on outside contractors for new construction that is undertaken

However, the need to be able to effectively respond to outages is a role that has not changed but has taken on a greater significance as staffing levels have been reduced. Field force proximity to where an outage occurs is a key factor in response time, necessitating that field forces be deployed in a manner to minimize response times.

Finding II-8 provided an illustration to demonstrate that a statistical approach to determining field force staffing levels could be used to correlate staffing levels with the ability to provide a certain level of response capability. This analysis needs to be completed based on the latest information available from AEP/Kentucky technology systems, including other factors discussed in the finding. This analysis should be conducted on an ongoing basis to determine the adequacy of staffing levels.

Recommendation II-6 Closely monitor performance indices for adverse trends (Refer to *Finding II-9*).

The performance indices within the Hazard/Whitesburg area have increased (gotten worse) in the last year in terms of number of customers impacted and customer minutes. Some of this increase might be explainable due to better reporting as a result of the improved systems (specifically PowerOn and HOIS). However, to the extent that this increase is not a result of the improved reporting, it is a cause for concern. One would expect that to the extent this increase is due to better reporting, the performance indices should "level off" if not come down in the next year (2003). As a result, these indices should be closely monitored and reported for the next several years.

Recommendation II-7 Develop a method for addressing momentary outages (Refer to *Finding II-10*).

SAIFI, SAIDI, and CAIDI are industry recognized ways of measuring electric system reliability; however each of these indices requires that an outage be "identified" before it can be measured. This identification process to a large part depends on the customer calling AEP/Kentucky to report an outage – unless the outage causes a remotely monitored protection device to activate and lock out. At least two ways of monitoring momentary outages exist:

- **Hardware related** – The identification and installation of some type of equipment that could be placed into the electrical network to report information on momentary outages.
- **Customer related** – AEP/Kentucky could provide customers with postage return cards that can be used to report momentary outages. If the message to the customer is that AEP/Kentucky is interested in knowing how well they are serving you, getting customers to participate in the process might offer other benefits.

III. Engineering

This chapter addresses American Electric Power (AEP)/Kentucky's design engineering activities.

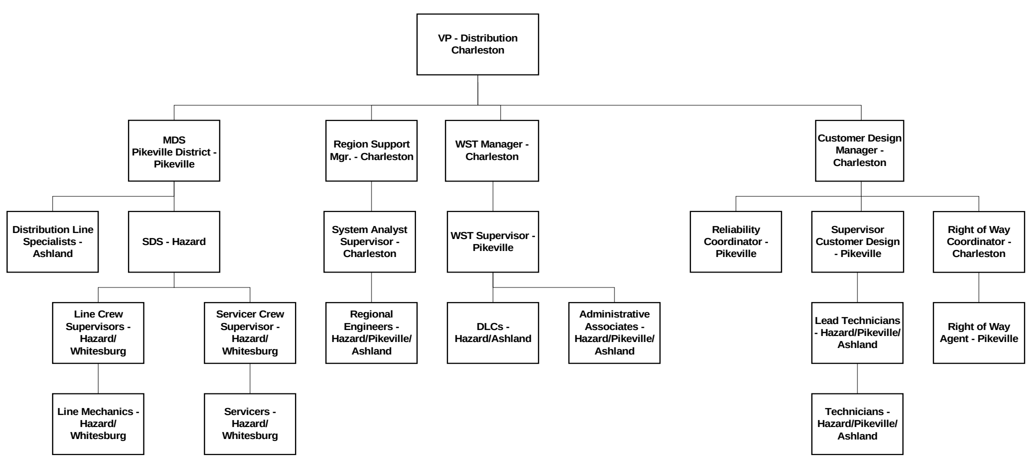
A. Background and Perspective

The responsibility for the design engineering function is divided among the Charleston Region engineering groups located in Charleston, WV and Roanoke, VA; a Regional Engineer located at the Hazard Service Center; and Engineering Technicians located at the Hazard Service Center. The Station Resources group in Roanoke does station design. The Technical Services group in Hazard does the design of the line-related projects.

Organization and Management

An organization chart showing the Regional Engineering group and Customer Design group to the Hazard Service Area level is included in *Exhibit III-1*.

Exhibit III-1
Charleston Region Engineering Groups Organization Chart



Regional Engineering Group

For Distribution Planning purposes there are five regions:

- Charleston, WV (includes AEP/Kentucky)
- Columbus, OH
- Fort Wayne, IN
- Tulsa, OK
- Corpus Christi, TX

Each region has a Senior Engineer assigned who reports to the Manager of Distribution Asset Planning inside the Asset Management organization and who is responsible for the actual work in their region (day-to-day planning activities). The Senior Engineer and his work team develops the details of a proposed project, including:

- Project description
- Capital cost
- Cost/benefit analysis

In relation to the overall planning process, the Regional Engineering staff and local service area operations staff review the operating data in the fall of each year after the summer peak load through an operational review, which is called the Demand Forecasting Meeting. This operational review leads to a forecasting meeting with Regional Engineers, Technicians, and Servicers. In the spring of each year, the same group performs a capacity review at the Capacity Planning Meeting, which results in the identification of those projects that are planned for completion in the next eighteen months.

In regard to reliability considerations, the Regional Engineering Group looks at the impacts of improvements on reliability in terms of SAIFI and CAIDI. This group also looks at the loading on components and estimates of the ability to recover from an outage. Much of Asset Management is load-driven based on capacity planning. However, some projects (a small percentage) are driven totally by reliability considerations.

The "bulk budget" (which is for all of AEP) is used by the Distribution Planning group for longer-term projects that are larger. The regional budget would generally be used for smaller, very reliability-driven projects. The regional budget is mostly intended for daily repairs and improvements of a more immediate nature. A large project is generally considered to be one that is over $125,000. However, there is now an ability to fund smaller projects out of the bulk budget, if the projects are forward thinking, improve the system, and resolve longer-term issues.

The bulk budget is divided into categories by type of project. The bulk budget is determined by the AEP corporate Asset Management organization, which gives them a total budgetary number for AEP as a whole. The work plan (of projects) for the year is subject to change throughout the year due to new or cancelled projects. The Distribution Asset Planning group then breaks down this lump budgetary number into regional budgets that are based on the priority of the projects that are forecast for each individual region. (See Chapter III – Asset Management for a more detailed discussion of the budget process.)

The 2003 work plan, which was approved in June 2002, included the projects by region and the amount budgeted for each project. Generally the Distribution Planning group is planning for load and capacity at least one year into the future. Each of the individual projects that have been identified has a justification developed for it that is called a "business case." The business case is done prior to initiation of the project, but after it has been approved as part of the work plan. At this point the project is "authorized" for undertaking by management.

The demand (load) forecast is developed by the Distribution Planning Group based on actual demands and loads including load growth projections. Potential sources of new demand are also obtained from Regional Engineers at the field level.

Regional Engineering Function in Hazard

The Regional Engineer located at the Hazard Service Center works with the day-to-day operations of the Hazard Service Area system. As such, the Regional Engineer is responsible for the coordination of engineering issues, power quality, over-current protection, low voltage, monitoring of power quality, power factor correction, reactive current, load current, and reliability. Additionally, this position is responsible for handling customer service complaints relevant to power quality or reliability. AEP recently transferred this responsibility to the Regional Engineers to standardize the manner in which this function is handled across the company and to improve the ability to respond directly to customer problems. The Regional Engineer also does initial studies of new or upgraded service additions.

Generally, projects that are over approximately $125,000 are Asset Management projects and are funded through that group. Projects that cost less than $125,000 are generally handled locally through various blanket budget allocations, which are a part of the established regional budgets. (See Chapter III – Asset Management for a more detailed discussion of the budget process.)

Three Regional Engineers in the Pikeville District organization are assigned to the Kentucky service territory of AEP. Two other Regional Engineers, who are also part of the Pikeville District organization, are physically located in and assigned to West Virginia. There are a total of 23 Regional Engineers assigned to the entire Charleston Region.

One of the primary reports that the Regional Engineer in Hazard uses is the Three Times Primary Device Outage Report, which lists those devices that have failed three or more times in the past year (12-month rolling average) including storm outages. This is a report that is combined for the Roanoke and Charleston Regions and is available on the Web. This report, formerly known in the old Transmission and Distribution Interruption Report (TDIR) program as the "Repeat Device Outage Report", has been in use for over 25 years. It was used on an informal basis by engineering and management to identify primary sectionalizing devices, which previously experienced repeated sustained outages in a defined reporting period. The Three Times Primary Device Outage Report as it currently exists, is now a formalized region-wide process to identify and mitigate repeat device outages. This new formalized report began in January 2002.

When a circuit shows up on the report that is within the Regional Engineer's service area, the Regional Engineer will research the reason for the problem. The report is by circuit and is updated on a monthly basis. The Regional Engineer in Hazard has refocused on this report in the past few months to better address reliability problems in the Hazard Service Area. While the Regional Engineer has a standardized deadline for responding to the items (in the assigned territory) that are listed in the report, response to the identified problems is usually immediate.

The Regional Engineer previously used the TDIR on a regular basis until it was phased out. The TDIR system is now only used for historical data, as no new data has been entered into it for the past year. The Regional Engineer now uses the Business Objects Report, which is produced by an engineer in Roanoke who is the Regional Team Leader for Reliability. This report provides the capability of searching the data based on a number of parameters, including SAIDI and SAIFI. It is part of the Enterprise Applications Solutions (EAS) software, which is currently in the final stages of implementation. Business Objects is a database-reporting tool that supports the EAS platform.

Regional Process Improvement Groups were formed in the February 2002 timeframe to look at how Regional Engineering can improve current processes. Five performance areas were studied under the System Analysis Performance Process, including:

- New service
- Power quality
- System reliability
- System analysis
- Asset management

Other computer systems that are used on a regular basis by the Regional Engineer in Hazard include the following:

- Marketing and Customer Service System (includes account history and status)
- Order Processing system (OPS) (used for handling new service orders)
- Numerous databases in Lotus Notes
- Abnormal Equipment Database (The Distribution Dispatch Center (DDC) enters information on any equipment that is found to be defective into this database; the Regional Engineer can then assess the problem and produce a work order if required)
- CYMEDIST (a CYME International package that produces the distribution system analysis tools utilized by AEP, contains engineering one-line diagrams of circuits, voltage drops, and

short circuit calculations and CYME Link that pulls in circuit design data from the Small World Software)

- Small World Software (used for storing circuit design and geographic information)
- Integrated Station Information System (ISIS) (contains all substation operating data and note)
- Distribution Estimating Tool (used for producing high level estimates of potential projects based on the construction units contained in LD Pro)
- The Protection Verdict Over-current Protection Program (VPRO) (used for over-current protection design)

Design Engineering in Hazard

Design engineering related to service installations is done by a group of six Technicians located in the Hazard Service Center. These Technicians are responsible for performing field visits related to customer order requests that potentially require construction work, as well as identifying and implementing required reliability improvements. Additionally, they communicate with customers, provide cost estimates when required, and process field work orders. The Technicians in the Hazard Service Center handle the five-county area that comprises the Hazard Service Area. They can and do share the workload with the Technicians in the Pikeville office in cases when one of the offices is overloaded with work. For the past three years, six Technicians have been located at the Hazard Service Center; previously ten Technicians were in this center.

The specific job responsibilities of the Technicians located in the Hazard Service Center are as follows:

- Two of the Technicians are assigned to larger jobs that require surveying and the placement of additional poles
- Three of the Technicians, each assigned to a specific geographic area, work on smaller new service jobs that do not require surveying
- One of the Technicians is a floater who helps out the others and also does jobs related to the replacement of reclosers and poles

A customer requesting new service would call the Solution Center where the order details are entered into the Order Processing System (OPS). The order is then transferred to a clerk in Hazard who would assign it, based on its size and content, to a specific Technician for completion of the design work.

The Technician performs a site inspection to determine what facilities would need to be added to provide service to the customer. The Technician then enters the job into LD Pro, the engineering computer aided design (CAD) system. If there is a reason for a hold, then a clerk would enter a "hold" into OPS. The LD Pro system then produces the work order for the line crew or Servicer to use in installing the requested service.

The Technicians in the Hazard Service Center previously handled customer service complaints relevant to power quality or reliability, but that responsibility was recently transferred to the Regional Engineer in Hazard. This change was made to standardize the manner in which this function is handled across the company and to improve the ability to respond directly to customer problems. If the Regional Engineer determines that a service upgrade is required, the Regional Engineer then transfers the requirements for an upgrade to the Technicians for design.

Engineering Standards

AEP maintains a Central Standards Group, located in Columbus, OH, which is responsible for development and maintenance of company-wide standards for AEP in relation to the design engineering function. Additionally, the Central Standards Group participates on several national committees of various national standards organizations to have input into the development of new or modified national standards.

One person from the Central Standards Group is located in each of the regions to ensure that proper communications exists between the Engineers in the region and those of the Standards Group. The Central Standards Group in Columbus consists of five people. In the regions there are four engineers located in the eastern portion of AEP and four engineers located in the western portion. The Central Standards Group engineer for the Hazard Service Area is located in Roanoke, VA.

The Central Standards Group is also responsible for the maintenance of the Compatible Units System (CUS), which is a listing of the standardized materials and quantities that are required to perform routine field jobs. CUS includes an estimate of the hours for installation and removal and some standard maintenance activities. This system is used to develop standard costs for materials and jobs for the company as a whole.

Transmission and distribution lines are designed and constructed to conform to the National Electrical Safety Code (NESC) standard that is in effect at the time of construction. It is the role of the designer to adapt the design at hand to the constraints that exist, while remaining in compliance with the standards. For example, distribution line strength and clearance variables must be incorporated as follows:

- ***Line strength*** – The NESC defines three grades of construction that can vary from span to span throughout the line, depending on the individual line structure's function and proximity to the public and other objects.
- ***Conductor clearances*** – Every overhead line must be located on a route, and on poles of sufficient height, such that conductors have adequate vertical and horizontal clearances from the ground, buildings, railroads, other structures, and other conductors.
- ***Pole structures*** – The selection process for pole structures requires that the most economical pole be used to support the expected loads on a given structure. The height of a pole is usually

based on clearance considerations. Loading on a pole (or structure) takes into consideration the worst case scenario of load factors including wind pressure, ice accumulation, and attached equipment loads (conductors and associated hardware), or a combination of these factors.

AEP has three general reasons for changing its company-wide standards, those being:

- A manufacturer introduces a new or modified piece of equipment, resulting in the Central Standards Group performing a pilot testing program on that piece of equipment in the field through the installation of sample pieces of equipment
- Feedback from the field on problems that have been encountered may result in an engineering standards change to resolve the problem
- Changes in national industry standards (such as NESC standards) may result in a modification being made to the existing design standards

The Central Standards Group regularly interfaces with Dolen Labs, which is an equipment testing and research center. Dolen Labs is used on a regular basis for testing new equipment. Additionally, Dolen Labs performs testing on equipment that has been found to perform poorly.

The AEP Engineering Design Standards are maintained in both an on-line and a paper version. The Central Standards Group sends out email notifications to designated employees regarding changes that have been made to standards to make them aware of the changes that are posted on an internal website. It is the intention of the Central Standards Group to do mass releases of updates to the field for non-critical items. The Central Standards Group also provides standards documentation to contractors that are employed by AEP. There is a contract coordinator in Charleston that oversees the contractor relationships and contracts. The contractor's billing is generally based solely on the Compatible Units System.

Engineering standards documentation is currently being updated with the intention of merging the AEP standards and the Central and Southwest (CSW) standards to create one unified set of standards for AEP nationwide. This effort is also including input from the field forces into the newly created standards. The final result of the project will be the development of two separate manuals, specifically:

- Engineering Standards, which contains both the Engineering Standards and the Construction Standards
- Construction Standards, which contains only the Construction Standards

This division into separate volumes should make the documents easier to work with. The development project was completed in October, 2002. Training is currently being done by the Central Standards Group for the AEP Engineering and Construction groups across the company. It is anticipated that training will be done in AEP/Kentucky during the first half of 2003.

B. Findings and Conclusions

Finding III-1 The design engineering function as it is performed by various groups within AEP for the benefit of the Hazard Service Area operations is commensurate with contemporary electric utility industry standards.

The division of responsibilities between regional and local groups is properly structured to allow significant local input, while still adhering to the regional goals and objectives. The number of engineers on staff in both the regional offices and the Hazard Service Center is appropriate in consideration of the normal workload. All of the engineering groups have access to the tools, information, and systems that they need to properly support the operation of the system.

Finding III-2 The AEP Central Standards Group provides the engineering staff with a robust and up-to-date set of design standards to use in the completion of their work.

The AEP Central Standards Group does a good job of maintaining and updating the engineering design standards, as witnessed by their current efforts to merge the design standards of AEP and CSW to have greater standardization and to avail themselves of the best of both sets of standards. These continuing efforts ensure that the engineering designs created by the AEP design engineering groups are based on the latest and most complete standards possible.

C. Recommendations

None

IV. Transmission and Distribution Operations

This chapter addresses American Electric Power (AEP)/Kentucky's transmission and distribution operations activities.

A. Background and Perspective

The Distribution Line Operations Organization of AEP/Kentucky is responsible for the construction, operation, maintenance, and repair of the AEP/Kentucky distribution grid. For the Hazard Service Area, the management of this function is located in Pikeville, KY. A description of the organization and its functional responsibilities is included in the following text.

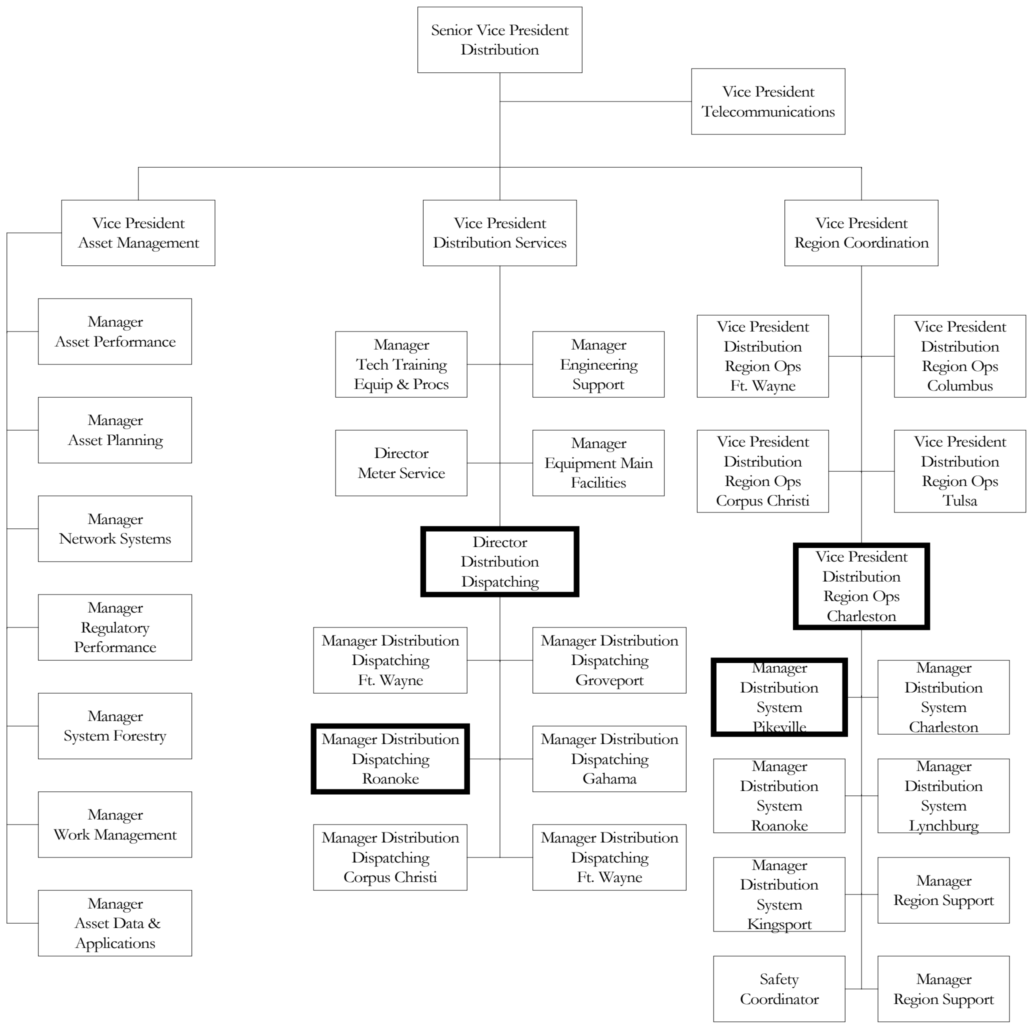
Distribution Line Operations Organization and Management

The Charleston Region Distribution Line organization is shown in

Exhibit IV-1 on the following page. The Manager – Distribution System, Pikeville manages the Distribution Line Operations group for the Pikeville District, which totals 132 people as follows:

- One (1) Manager of Distribution Service (MDS)
- One (1) Secretary
- Six (6) Supervisors of Distribution Service (SDS)
- Two (2) Line Specialists
- 24 Line Crew Supervisors (working Foremen)
- 98 Line Mechanics and Servicers

Exhibit IV-1
Regional Distribution Line Organization



In the Hazard Service Area (HSA), which includes the Hazard and Whitesburg areas, the following personnel (FTE equivalents) are on staff:

- One and a half (1½) Supervisors of Distribution Service (SDS)
- Eight Line Crew Supervisors (working foremen)
- 22 Line Mechanics and Servicers (16 Line Mechanics and 6 Servicers)

Each of the HSA line crews includes at least one supervisor (with supervisors doubled up at times to make the most efficient use of crews), with line crew composition as follows:

- Three (3) 4-man crews
- One (1) 5-man crew
- One (1) split crew

The Distribution Operations organization is divided into two functional segments, specifically:

- Line Crew Operations organization that is responsible for the construction of new distribution lines and facilities
- Servicer organization that is responsible for performing troubleshooting, service restoration, upgrades, and installation work on the distribution system

The organization and operations of each of these groups is detailed in the following sections entitled Line Crew Operations and Servicers.

Line Crew Operations

Organization and Management

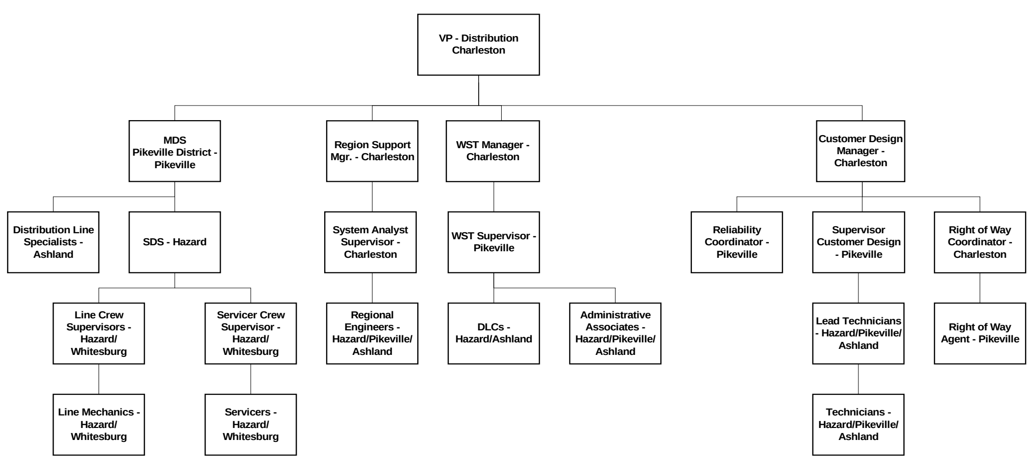
The Supervisor of Distribution Service (SDS) in Hazard is responsible for managing and scheduling eight Line Crew Supervisors and 22 Line Mechanics. Their primary responsibilities are the construction on new distribution lines and facilities and the setting of new poles. Most of these crews work out of the Hazard Service Center. One line crew and one pole setting crew work out of the Whitesburg Garage, where a small storeroom is also located. This storeroom is the responsibility of and maintained by the Hazard Storekeeper.

Line Mechanics are stratified into four major classifications according to their skill, experience, and training. A new employee would start out as an Apprentice with a Line Mechanic D classification and work up to Journeyman status as a Line Mechanic A. In the Hazard Service Area currently only two Line Mechanics are not in the top of the A class; they are in the second step of the A class. The experience levels of the Line Mechanics in the Hazard Service Area range from 6 years to 32 years with an average of approximately 22 years. AEP/Kentucky is monitoring the fact that there have not been many new entrants into the Line Mechanics ranks in the recent past and, as such, the work force is aging. This issue is being reviewed across AEP.

Work Management

Due to an identified need for better work planning, the position of District Line Coordinator (DLC) was established in the 1995 timeframe. These DLCs are responsible for the scheduling and coordination of work by the Distribution Line field crews within a specific service area. They perform this function through their activities as part of the Work Scheduling Team (WST), which is detailed in the following text. The DLCs are part of the Technical Services organization. This is a regional organization that also includes the Engineering Technicians who are responsible for performing the engineering design work that is done in Hazard. An organization chart that shows these groups to the Hazard Service Area level is shown on *Exhibit IV-2*.

Exhibit IV-2
AEP Distribution Organization – Charleston Region



Previous to this organizational change, the scheduling function was the responsibility of the SDSs. The establishment of the DLC position has allowed the SDSs to focus more on safety and quality considerations and less on the scheduling function. It has also allowed for better coordination with stockroom personnel. This is done by means of a weekly anticipated project schedule that is transmitted to the stockroom personnel the week before the work is scheduled. This allows the stockroom staff sufficient time to ensure that the equipment and materials required to complete the work are in stock. This is particularly important in the case of equipment that must be special ordered.

The DLC prioritizes the work based on an "A" through "I" priority code, with "A" being the highest priority projects. The line crews are generally shared with other areas for at least several weeks a year in order to balance the workload. This allocation of the field forces is done based on the results of a coordination phone call that is held on a weekly basis.

Work management is done through the use of Planning Scheduling Process (PSP) software, which is an old system that uses units that have been time studied and that have time estimates associated with units. All of the pending work is backlogged in PSP. The managers (MDS, SDSs, and DLCs) look at the current workload across the Pikeville District and distribute the personnel based on that information and historical workloads. The PSP software and its functionality are detailed in greater detail later in this section.

The Work Scheduling Team (WST) is responsible for analyzing the workload and making recommendations to the Manager of Distribution Service regarding crew allocation and project scheduling. It is the intention of AEP/Kentucky to try to do as much of the work as possible on an in-house basis, rather than relying on contractors. Most of the system improvement (asset) work is done in the fall and winter, with most installation and upgrade work done in the spring and summer.

There is one WST for the Pikeville District and one for each of the other three districts in the Charleston Region. The coordination among personnel is done through a weekly telephone call (Wednesday of each week) that includes the following personnel:

- WST Supervisor of Distribution Service (SDS) from the Pikeville District level
- Scheduling Supervisor from the Pikeville District level
- DLC from Hazard Service Area
- DLC from Pikeville Service Area
- DLC from Ashland Service Area
- DLC from Logan Service Area
- Servicer Supervisor

This system of DLCs and coordination phone calls has been in place since the fall of 2000. For regular work there is a sharing of the work crews based on the WST recommendations. After the district call is completed, there is a regional phone call that takes place, with the WST Supervisor of Distribution Services or the Scheduling Supervisor serving as the representative for the Pikeville District. These calls deal only with the Distribution Line work load. The WST (through the DLC) attempts to give the work orders to the SDSs on Thursday for the next week's work, so that they can better plan the workload.

The Weekly Crew Plan, a homegrown database system that is about two months old, tracks the work to be done versus work completion, schedule targets, material considerations, and how well the crews in aggregate have done on a weekly basis. It replaced a typed manual report. It was developed by the Stores Supervisor and is shared with the Line Crew Supervisors to aid them in their planning and performance monitoring. There are also regional scorecards that track the progress of the Charleston Region as a whole.

Each district is budgeted for a certain number of employees. The funds for out-of-district crews are not cross-subsidized due to the fact that the expenses are all rolled up to the regional level. The costs of the individual projects are assigned to the individual districts.

Most of the work in the Hazard Service Area is residential in nature, although some work is done for large coal mines and is coordinated through the Business Services Engineer. Much of the residential work is comprised of installing service for mobile homes that are being relocated. While last year there were only 400 new customers added in the HSA, there was a significantly larger number of moves that were handled. There is not a lot of new residential construction and most of the work is driven by new service requests for new or relocated mobile homes.

Overtime is used primarily in emergency situations and is worked when there is a specific need. The overtime budget that is given to the district is based on the historical usage of overtime. This budget figure is based on only routine overtime, not on that overtime that is worked in emergency situations. For routine overtime, the responsible SDS would approve work that is determined to be necessary based on efficiency or service-related considerations.

The productivity of the line crews is only monitored on a cumulative basis. Management does not systematically track productivity on an individual crew basis. The productivity target is for an average of 20 hours of constructive work per week for all of their crews in aggregate. The SDSs are responsible for monitoring and supervising the crews on a daily basis.

Safety and Quality

The Line Crew Supervisors have first line responsibility for safety and quality. The SDS has a monthly meeting with them to review the results that were achieved in the previous month. Daily Safety Huddles (developed by the SDS) are held with the crews in the garage. Information on “near misses” (almost accidents) is shared across the district via Lotus Notes. When an accident does occur, the manager of the area will send around a voice mail to the other managers for information purposes. The Safety Coordinator then performs a detailed investigation of all accidents.

There is a regional safety organization that is comprised of three Safety Coordinators who are responsible for the Charleston Region. The safety documentation is contained in a database in Lotus Notes. A spreadsheet is used to track the progress of the safety program. There are safety programs that are AEP-wide, but the safety scheduling and program development functions are handled by the local SDSs. The Safety Coordinators keep track of the safety items to be covered in the programs.

AEP has a comprehensive “D-Line Training Program.” This program evolved from the “Power Line Pro Training Program” that was developed by Tampa Electric, which was then tailored to the specific needs of AEP. Most of the training is focused on skills training for Line Mechanics and the application skills in how to use equipment. The instructors are veteran Line Mechanics who have been trained to be trainers on a full-time basis. There are 14 full-time instructors across AEP, with approximately two in each region. There are training centers in each of the five regions, including one for the Charleston Region in Cloverdale, VA. There is a separate Transmission Lineman training program that focuses on the high voltage lines (over 69 KV). There is very little cross-training between the T&D groups; however, more cross-training is done at the advanced levels.

Distribution Line personnel also have a standardized AEP training program. Line Mechanics must go to designated classes and pass two tests before they can be promoted to the next level. There is also a standard recertification class that all Line Mechanics must regularly complete. Prior to this structured training program, most of the training was done via on-the-job training. Advanced journeymen level training gives the Line Mechanics a chance to reinforce their skills through continuing education.

Budgeting

In terms of yearly budgetary goals established in Asset Management (AM), the budgeting system is set up on a monthly basis. Asset goals are established by AM for various types of equipment for each individual service area. The Engineering Department determines specifically where the new/upgraded equipment is to be installed. The District Manager is responsible for meeting these budgetary numbers. Pole replacement is currently a major emphasis in an effort to improve reliability. Poles are a longer term investment as they can cut the duration of outages. The poles that are replaced are generally in the 50-year old plus range. In the opinion of field personnel, the pole inspection and replacement programs, as well as the animal protection program, are beginning to pay dividends in terms of both cost savings and reliability. This topic is covered in more detail in Chapter III – Asset Management.

Bargaining Unit Relationship

The Distribution Line management in Pikeville believes that there is good communication and coordination with the union in the Hazard Service Area. IBEW Local 978 was established in the HSA in 1998. While there were some minor problems encountered at the time of startup, relations have smoothed out over the course of time. Hazard and Whitesburg comprise one bargaining unit. The Ashland and Pikeville service areas just became unionized in 2002.

Use of External Contractors

The Distribution Line organization, which makes use of external contractors on an as-needed basis, is currently using the services of four line construction contractors. These contractors are generally used on large job conversions, highway relocations, and specialized jobs (such as reconductoring work). Contractors bid for work on an AEP-wide basis. The regional organization coordinates and manages the contractor utilization.

Servicers

Organization and Management

A Servicer is generally an employee who has come up through the Line Mechanic ranks and has a significant amount of experience. The Servicers, who are on call 24 hours a day throughout the year, are responsible for performing troubleshooting, acting as first responder for outage repair and restoration, distribution system maintenance, upgrades, and installation work within specific geographical territories.

They generally function as single-person crews who work out of a bucket truck. The Servicers do not perform disconnections for non-payment as that is the responsibility of the meter readers.

There is one Servicer Supervisor for all of the Pikeville District, including the HSA. There are 26 Servicers (including employees doing Servicer work, but without the position title) in the Pikeville District, not counting those who work in the Ashland Service Area. The allocation of the Servicers in the Pikeville District includes the following:

- Seven (7) in Hazard/Whitesburg
- Four (4) in Logan
- Five (5) in Williamson
- Two (2) in Paintsville
- Eight (8) in Pikeville (one of the Pikeville Servicers works the evening shift.)

In the Hazard Service Area seven employees perform the Servicer function, which breaks down to five assigned to Hazard and two assigned to Whitesburg. Of the seven employees, in Hazard there are two A Line Mechanics and in Whitesburg there is one who are currently doing Servicer work, but without the title. These Line Mechanics do get step-up pay to make them basically equivalent in pay scale to the Servicers. All of the Hazard/Whitesburg Servicers keep their trucks at home with two of them reporting to the Hazard Service Center on a daily basis due to their proximity to the center. Part of the reason that management is using A Line Mechanics in the Servicer role is that management does not know the long-term status of many of the seven employees who are currently on long-term disability (LTD) status.

It is management's current intention to transfer one or two additional Line Crew Supervisors (who currently oversee the work of the Line Mechanics) in the Hazard Service Area into the Servicer position, as there are currently more Crew Supervisors than are required, but a shortage of Servicers. There are currently eight Crew Supervisors in the Hazard Service Area with only fifteen Line Mechanics to supervise. This change will require union approval. The union contract has been in effect in Hazard since 1998. There is currently one Line Crew Supervisor who is acting as a Troubleshooter and performing Servicer work in the Jackson area.

Work Management

The Servicer Supervisor visits the Hazard Servicers approximately once every two weeks and talks to them on a regular basis via telephone. The Servicers in Hazard attend the regularly scheduled safety sessions with the Line Mechanics in the Hazard Service Center. Servicer management currently does not have an ability to track the number of hours that are actually spent on a callout job versus the number of hours that are paid for. However, they are able to distinguish between those overtime hours that are spent for routine work versus those that are spent for restoration and repair work.

The Servicers are set up to act as first responders for trouble calls on a geographical basis with well-defined boundaries. During normal working hours, the service territory boundaries become less strictly defined and are generally based on the work load for that specific day.

The Servicers submit a daily overtime sheet. Due to the distances involved, the SDSs in the HSA perform much of the day-to-day performance monitoring of the work of the Servicers. In the near future (currently scheduled for January 1, 2003), the day-to-day management of the HSA Servicers will revert to the local SDSs in Hazard. The Pikeville office will maintain the functional control of the Servicers. Overtime for Servicers is paid at a rate of time-and-a-half for time over their regular shift hours. After 16 straight hours the pay rate goes to double-time. It also goes to double-time on Sundays and holidays. Additionally, there are callout minimums as follows:

- 2 hour callout minimum for the period from the ending time of their regular shift to midnight
- 3 hour callout minimum for the period from midnight to 6:00 a.m.

Most of the overtime that is worked by the Servicers is due to emergency work. The routine work that they perform is generally a relatively small percentage of the overtime total.

There are five blanket accounts that the Servicers normally charge their time to, specifically:

- Residential monthly for new service
- Residential upgrade
- Commercial/industrial monthly for new service
- Commercial/industrial upgrade
- Distribution system correction (AM projects)

Trouble time is differentiated from routine work time based on the charge numbers used. Travel time is incorporated into the time for the job to which the Servicer is traveling. The most frequently used charge numbers include the following:

- 214 – Routine work
- 233 – Routine trouble
- 234 – Major storm
- 227/228 – Routine maintenance

Based on the above charge accounts, the totals for trouble time versus routine time can be pulled from the PSP system in either detailed or summary fashion. The Servicer Manager and Manager – Distribution Service monitor this data on a regular basis.

Outage Restoration

Summer storms are generally very localized in nature, making them more difficult to predict. Snow storms are generally slower in coming but endure longer, often resulting in longer duration outages. The HSA does not experience very many trouble calls due only to rain. The wind generally causes more problems for them than rain does. In all of these storm situations, the majority of the outages are directly caused by damage due to trees and limbs falling or contacting the lines; the weather itself does a relatively small amount of damage. Lightning-related outages are a significant cause of outages, although not to the extent of tree-related outages. In response the company has gone to a heavier class of lightning arrester (called Scouts), added more lightning arresters, and gone to three grounds on all new poles (only on new construction, not retrofitting) to reduce the damage caused by lightning. In serious storm trouble situations, the Technicians (engineers) will first work to perform damage assessments, and then the Line Mechanics will be called out to begin performing line repairs.

In outage situations, the Distribution Dispatch Center (DDC) in Roanoke, VA will contact the designated Servicer for the specific geographic territory directly via pager, radio, land line, or cell phone. If they cannot reach that person or that person declines to respond, the DDC will either begin to work their callout listing or they will contact the designated Duty Supervisor for that day. The Duty Supervisor is a rotating Crew Supervisor that is on duty for one week on a 7x24 basis for the purpose of serving as the local coordinator for trouble or restoration activities. The Duty Supervisor can assist the DDC in finding employees to work trouble calls. When a situation goes beyond the ability of the Duty Supervisor, the SDSs and the local Work Scheduling Team will get involved. At that point the coordination of the dispatching effort will revert to local control. The DDC attempts to contact the employees in the local area in advance to inform them of approaching storms so that they can prepare.

The Servicers can generally handle approximately 90% of trouble calls that come in without assistance. If they cannot handle the outage or need equipment, the Servicer will call the DDC for assistance. The top rated A Line Mechanic acts as the backup if the Servicer is on vacation or otherwise unavailable. The contacts generally go out over cell phone, pager, land line, or company radio.

Software Applications

In autumn of 2001, AEP/Kentucky installed laptop computers in the bucket trucks that allow the Servicers to pick up most of their work assignments through a daily download from the Spectrum system, which downloads the job orders from the Order Processing System (OPS). Additionally using the laptops workers can access the LD Pro and Individual Out Wandering Around (IOWA) software, which provide access to computer-aided design (CAD) drawings and geographic location information respectively.

AEP is implementing the Severn Trent System (STS) software package, which is a wireless laptop scheduling and work monitoring system. It is scheduled to be fully implemented in the Charleston Region by mid-year 2003 (according to the current schedule). This enhanced wireless data communication system should enhance the ability to get the proper trouble information to Servicers in an efficient and expeditious manner. The implementation program is described in greater detail later in this section.

Servicer Scheduling Process

The routine work that is performed by the Servicers (such as new service installations, outdoor light installations, etc.) is scheduled by the Administrative Associates who are report to the DLC in the Hazard Service Center. The Administrative Associates work to schedule and ensure the completion of the work plans created by the WST. The Administrative Associates use a workflow application that is included in the Order Processing System (OPS) software to perform most of their scheduling functions. Each morning, the Administrative Associates go through the new service orders, upgrades, or outdoor light orders that were input to the system since the prior day's close of business. The Administrative Associate makes a determination, based on information provided by the customer, as to whether a Technician (engineer) is needed to inspect the site and/or perform design services. A Technician would be required on those jobs that require new poles to be placed or if there are other factors that would complicate the installation. If a Technician is required, the Administrative Associate schedules a Technician visit to the site within 48 hours of order receipt. The Administrative Associate will contact the customer on orders for new service, upgrades, and light installation to set up an appointment time. In the case of simple repairs or light repairs, they make contact with the customers as required, based on customer need.

If the customer facility is inspected and ready for a Servicer to be dispatched, the Administrative Associate enters the order and appointment time (if applicable) into the Access Scheduling Database, which is the primary tool for monitoring and scheduling work orders. The screens are color coded to ensure that the priority jobs are highlighted. As the Solutions Center can only see data in OPS (i.e., they cannot view the Access Scheduling Database), the Administrative Associate also enters the appointment times into OPS so that if a customer calls with a question concerning an appointment the Solutions Center representative will be able to respond accurately.

The orders are transmitted to Servicers in one of two ways:

- Through the Spectrum System that downloads the orders into the Servicers' laptops when they log onto the local area network (LAN) in the Service Center or dial-in to the system.
- Through hard copy print outs that are picked up at the Service Center by the Servicers (or faxed to their home bases). This method is used only for those orders in OPS that cannot be pushed into Spectrum. Such orders include:
  - Combination accounts (those with both electric service and an outdoor light)
  - Internal work
  - Installation or removal of lights

The Servicers then prioritize their daily work assignments based on the immediacy of the jobs and the Servicers knowledge of his or her assigned service territory. They will then accordingly arrange the jobs on their laptops to set the day's work schedule. As new orders are entered into OPS throughout the day, the Administrative Associate constantly monitors it to pick up and work on newly entered orders.

Each of the Servicers transmits a work order closeout sheet on a daily basis to the Administrative Associate showing those jobs from both the Spectrum and hard copy job listing that were completed that day. The Servicers close out their Spectrum jobs on their own laptops and then upload the information to the network to close out the job in OPS. On a daily basis the Administrative Associates verify that the jobs have been closed out properly in OPS. For those jobs that come out in hard copy only (those that are not in Spectrum), the Administrative Associate will close out the jobs in OPS.

If a Servicer cannot do a job at the appointed time or by the required date, he will call the Administrative Associate to have the job rescheduled with the customer. Delays generally occur due to trouble calls that arise during the course of a day or jobs that take longer than estimated. When a trouble call is received by the Servicer from the DDC, the Servicer will inform the Administrative Associate of their new schedule so that the customers may be contacted as required. The Administrative Associate does not get notification of trouble calls from the DDC directly. In general, the Servicers are not supposed to go home for the day until they finish all of their daily assigned jobs that have been designated as high priority jobs. The overtime that is accumulated as a result of finishing high priority jobs accounts for only a small percentage of the total overtime that is charged by Servicers.

Distribution Dispatch Process

Organization and Management

Outage reports and other trouble calls that are received from AEP/Kentucky customers in the HSA by the Solutions Center are transmitted to the Roanoke DDC for dispatch to the employee who is designated as first responder for the specific geographic area where the trouble is located. The Roanoke DDC dispatches for the entire AEP Charleston Region, which is composed of four districts. The Roanoke DDC, which has 30 dispatchers and other technical employees on its staff, is larger than that in Columbus, OH in terms of customers and geography. This staff is broken down as follows:

- 23 employees are either Switching or Trouble Dispatchers
- 3 Switching Coordinators (who set up planned outages and perform training for the field forces)
- 2 Electrical Engineers; one works with the Switching Coordinators to coordinate tap changes and mobile transformer installations and also works with loading issues on planned outages, while the other is a new position that works on training of the Trouble Dispatchers, improving the dispatch process, and problem areas on the system. The management of the DDC is currently working to get more training for and consistency among the Dispatchers.
- 1 Staff Associate (who works with time reporting and computer systems) will also take calls from the Solutions Center during storms and will do callbacks, as required.
- 1 Data Analyst located in Huntington, WV is responsible for scrubbing the data following outages to make sure that the outages and their restorations have been reported correctly

The DDC also has a dedicated technology support person that takes care of the servers and 25 workstations (not technically part of their group, but assigned to it on a full-time basis).

The DDC has been located in Roanoke since 1998 when it was originally established just for servicing central Virginia. The Kingsport, TN service territory was subsequently added. Then, on February 1st of 2002, the Pikeville District dispatching function was switched to Roanoke. Previously Pikeville did its own dispatching during the daytime hours. As of June 1st of 2002, the Roanoke DDC was assigned the centralized responsibility for all of the former Roanoke and Charleston Regions. The Roanoke DDC currently serves 1.1 million customers in Virginia, Tennessee, West Virginia, and Kentucky.

To maintain specific familiarity with Kentucky operations, as part of the transition of the dispatching function from Pikeville to Roanoke, two Switching Dispatchers who had Kentucky dispatching experience were transferred from Charleston, WV to the Roanoke DDC, with two more brought over at a later time. There was also a transfer of a Trouble Dispatcher from Pikeville. The current staff of Dispatchers, which is exempt-salaried and non-union, has an average of 5 to 10 years of dispatching experience. Transmission Dispatch, which is a separate group from the DDC, is also out of Roanoke.

The Dispatchers work 8 or 12 hour shifts, with shifts rotated on a continuous basis. The DDC has the most staffing from 3:00 p.m. to 7:00 p.m. each day, as this is the most frequent time for summer storms to occur and people are getting home from work and discovering that their power is out. After 11:00 p.m., they have three (3) Switching Dispatchers that work on both trouble and switching dispatching. Switching Dispatchers are senior positions, having worked up from a Trouble Dispatchers.

The Shift Lead position is responsible for looking at DDC current loading, especially in relation to the weather conditions, as well as handling coordination with the field. The Shift Lead position is currently shared among four people. DDC management has been rotating several people through the position to test them for their ability to handle the job and will soon make a final selection as to who will be assigned to this position in the long term. The Shift Lead is also assigned the responsibility for sending out text messages to predefined groups of people in the field on the status of outages and weather related issues.

Dispatching Process

Customer calls reporting outages or other problems are directed to the AEP call center which is referred to as the Solutions Center. The Solutions Center enters the tickets into the Trouble Entry & Reporting System (TERS) through a Virtual Agent graphical user interface (GUI) front end. TERS then transfers the data into the PowerOn system, which has an outage engine that predicts the source of the trouble and identifies the isolating device that has probably caused the outage. The Solutions Center will call the DDC directly in those situations that involve safety issues. The Dispatchers put comments into the PowerOn system, as well as an estimated time of restoration of service. They also input any comments that are received from the field crews. The Solutions Center can see the comments that have been entered into PowerOn and the estimated time of restoration, but they cannot see the PowerOn system as a whole. The field forces then get back in touch with the DDC to report the time of restoration, what was done, and any materials that were used. The Dispatchers then enter this data and close out the ticket. The field crews do not have to complete any paperwork to close out a service restoration job.

The Roanoke DDC is set up with the Pikeville/Charleston service territory (5 trouble pods) at one end and the Roanoke/Kingsport service territory (4 trouble pods) at the other. Additionally, there are five pods in the middle of the room that are set up so that they can be used by either area in a storm situation. The DDC management is currently rotating Dispatchers among geographic areas to get more people familiar with each area under non-storm conditions. Generally, one or two Trouble Dispatchers and one Switching Dispatcher would be part of this rotation at any given time. In putting Dispatchers on a new geographical territory, the main problem encountered is who to contact in the field and how to contact them. There is an established database of contact information in Lotus Notes, which they are working to improve and update.

In relation to crew assignment prioritization for restoration work, the first priority is to address potential safety hazards, followed by restoring service to the largest blocks of customers possible. The DDC management is currently in the process of developing maps that will help the Dispatchers in efficiently assigning the crews from a geographical perspective. Also the Dispatchers will frequently contact the crews for input on prioritizing unworked outages.

In a storm situation, the Dispatchers would first look at redeploying the field crews based on the geographic location of the outages. They would pre-assign the work to the crews when possible based on local knowledge. This pre-assignment could be done electronically from the field. Line Coordinators and SDSs in the field would be used to provide local knowledge in severe situations. In very bad situations the actual control of the restoration dispatching effort may be transferred to the local field office. However, as the DDC becomes more familiar with the geographic areas for which it is responsible, this option is not expected to be used frequently in the future.

The Roanoke DDC managers will call the designated Relief Dispatchers based on how long they have been off duty. All of the Dispatchers are equipped with pagers to facilitate contact in emergency situations. A portion of the Region Engineering staff is located in Roanoke and they provide support and assistance during storms. Also a portion of the Region Records and Graphics groups are located in Roanoke and they also provide assistance as required.

The DDC implemented PowerOn in April 2002 and they have been refining its usage since that time. The previously-used outage management system was GUP (Graphical User Platform), which was developed in-house at AEP. It had no outage assessment engine and the dispatcher had to manually determine the isolating device that was believed to be the source of the problem. The DDC has been on the Small World System since 1996. The Small World system automatically feeds data into PowerOn. The Small World System contains routing optimization capability that would provide assistance in optimizing service dispatches. To take advantage of this capability, AEP would have to implement some least cost algorithms for getting from specific places to other places; however, there is currently no schedule for performing this work due to other projects that must be completed.

In relation to the rationale for centralizing the DDC in Roanoke, a team performed an extensive nine-month study of consolidating to larger DDCs. The Roanoke location was chosen based on the availability of office space, the reliability of the power supply due to being located in downtown Roanoke, the existence of excellent communications links, the availability of SCADA support in the building, the presence of a backup generator with sufficient capacity, the presence of good technology support, and the cost of living in the area. The study team did benchmarking with other utilities, most of which were also centralizing their distribution trouble dispatching process. It has been found that it is beneficial to centralize the DDC operations from a technology and training point of view. The Roanoke DDC has 40 to 50 crew headquarters in their assigned service territory. An additional benefit to centralization was the ability to establish 24-hour coverage without handoffs from the local dispatch centers that handled the dispatch function during the day (as it had been done in the past). Centralization also allows a more professional approach to how to sectionalize and tie to other circuits. The local offices may or may not have had the expertise required to do it on a localized basis. Additionally, centralization also allows greater flexibility due to the ability to pool resources and the larger number of available staff members.

As of July 1, 2002 the responsibility for substation and step-down transformers was transferred from the Transmission Distribution Center (TDC) to the DDC. The support group for TDCs is located in Roanoke. The Roanoke DDC is responsible for the placement of mobile transformers and their transportation. For a bank distribution transformer, the DDC would contact the Transmission Line Operations Group to get the mobile delivered, and then the DDC would handle the switching arrangements that need to be made.

Materials Management

The Hazard Storeroom is responsible for the provision of materials to the crews that operate out of the Hazard and Whitesburg Service Centers. The Hazard Storekeeper reports to the Regional Stores Manager in Charleston. In addition to the Hazard Storekeeper, there are three full-time attendants who work in the Hazard Storeroom.

The Hazard Storeroom is replenished every other Monday out of the AEP Fort Wayne Distribution Center, which supplies all materials, other than poles and transformers. Poles and transformers are supplied directly by the vendors. Hazard is supplied out of Fort Wayne as it has the most efficient transportation access. If the Fort Wayne Distribution Center is out of an item, it can be supplied by one of the other AEP Distribution Centers. A Pony Express delivery system may be used to have material delivered when it is necessary on an expedited basis.

The Hazard Storeroom tries to maintain a five-to-six week supply of all inventoried items. The Storeroom maintains a "Quick Pick" area that contains the highest volume, low value items that are regularly used by field crews. In the Quick Pick area the Storeroom tries to maintain a two-week inventory supply and performs cycle counts of material in the Quick Pick area three times a week for the purpose of replenishing the supply. Quick Pick items are charged against a blanket account for capital expense. These items are generally not assigned to specific jobs when they are checked out, unless the quantity that is taken is large and for a specific job. Normally this Quick Pick supply is used primarily to restock the inventory levels on the trucks.

The Materials Management System (MMS) is a homegrown AEP mainframe system that is used for recording inventory transactions and monitoring inventory levels. Every Wednesday the Hazard Storekeeper receives a reorder report from MMS that shows the items that need to be replenished based on established minimum/maximum inventory levels. These inventory parameters are generally determined according to the following guidelines:

- Minimum inventory level = 4 week supply at historical usage rates
- Maximum inventory level = 5 week supply at historical usage rates
- Reorder quantity = Difference between the maximum and minimum levels with adjustments made based on quantities that may be available or on order

However, the Hazard Storekeeper has the capability to modify these parameters based on past experience and knowledge of any special situations that may exist.

Picked material is assigned to an operation and maintenance (O&M) account or a capital account (work order) depending on whether the material is to be used for restocking the inventory in the truck or is to be used on a specific project. The Servicers and Line Mechanics fill out an order or pick list to requisition material. The material orders for trucks are picked the day before and loaded onto the trucks during the morning of each day.

The material is assigned to the individual jobs (work orders) when the items are issued to that job. At this point they are no longer tracked by MMS and are not counted against the on-hand Storeroom inventory levels, causing AEP/Kentucky to essentially lose visibility of the item at this point. However, a spreadsheet is maintained of the reclosers and three-phase pad mount transformers that have been issued to a job but are still located in the Storeroom or yard.

All inventory items are cycle counted at least once a year according to a monthly schedule that is arranged by item class. This schedule is the standard for all AEP storerooms and is developed by the AEP Supply Chain Group. The poles are counted on a monthly basis. An AEP internal auditor comes to each state once per year, so with three storerooms in Kentucky, the Hazard facility is audited once every three years.

Shrinkage has never been a serious problem in the recent past at the Hazard and Whitesburg storerooms. When a problem is discovered it is investigated. These identified problems are usually determined to be the result of keypunch errors rather than loss or theft.

When the Technicians write up a job they get a Compatible Units Report from the Transmission and Distribution Information System (TDIS). This report is a list of the material that is required to complete the associated work order. This list is used by the Storeroom Attendants to pick the material for each of the projects. The Storeroom gets a report of the jobs to be completed from the Work Scheduling Team and the SDS. The Storeroom looks at the jobs to be completed the next day and picks the required material on a daily basis. The Compatible Units Document Order Number is entered into MMS after the items have been picked to relieve the inventory of the items for that work order. Therefore, there is a linkage between the Compatible Units Report from TDIS and MMS that allows whole jobs to be relieved from inventory.

There is an ability to allocate material to a work order in MMS, before it is picked, to allow MMS to calculate the availability of material properly. This is only done for regular inventory items. For special items they do not do allocations as the material is ordered on a special basis.

Field Operations Telecommunications System

AEP maintains a centralized Telecommunications Group (Telecom Group) located in Columbus, OH, with local field technicians in most of the service centers. The Telecom Group maintains a 7x24 Telecom Center at One Riverside Plaza in Columbus, OH that handles any outages of the system that occur during the daily operation of the system. The Telecom Group also maintains over 130 sites throughout the eastern network.

AEP started a telecommunications system upgrade project in 1992, but not in AEP/Kentucky as the local company chose not to participate. AEP/Kentucky was included in Phase II of the project, which started in the 1995/96 timeframe and was essentially completed in 2000. The Telecom Group has been doing cleanup work over the past two years, to resolve those minor problems that were discovered with the communications system. The work on Phase II in Kentucky was finished in 2000 and has been being fine tuned since that time. Four additional towers were approved in Kentucky as part of additional funding for Phase II, including:

- Hazard tower site (servicing Hazard/mid- and north Perry County) – Work is completed
- Richardson tower site (servicing Ulysses/Peach Orchard/Gallup and Lowmanville – Work is completed
- Buckhorn translator site (servicing Buckhorn Lake area) – In the site acquisition stage
- Salyersville translator site (servicing Salyersville) – In the site acquisition stage

Since 2000 and during the fine tuning effort, the Telecom Group has been investigating those problems that have been reported by field crews. When a problem is verified, the Telecom Group sends out testing crews to determine the locations where the signal strength problems do occur. They then perform modeling of where the antennas and transmitters should be located. As part of this effort the Telecom Group will meet with the SDSs and MDSs in the local area to get their input on the situation.

A comprehensive study was initiated by the Telecom Group in 2002 to identify those areas in the AEP/Kentucky service territory that were still in need of additional or enhanced telecommunications capability. This study identified a need for additional towers or translators in the following areas of Kentucky:

- Southern Breathitt County (in the Hazard Service Area)
- Evanston
- Stinnett and Cutshin (in the Hazard Service Area)
- Leatherwood and Slemp (in the Hazard Service Area)
- Wheelwright and McDowell
- Mouthcard and Paw Paw
- Southeastern Martin County

The Phase III final plan of the project was approved and initiated in June/July of 2002, for the purpose of implementing the above identified facilities at an estimated cost of $2.775 million. The scheduled completion dates for the individual projects were prioritized by the field forces. Each of these projects is expected to take 1 to 1½ years to complete, mainly due to the time required for land acquisition. All of these new antennas and facilities planned for Kentucky as part of Phase III should be competed by 2004 or early 2005.

The Telecom Group maintains a Field Technician in the Hazard Service Center. Additionally, there is a Telecom Supervisor for eastern Kentucky located in Ashland, KY. There are numerous other Technicians in various locations across KY. The Technicians are assigned the responsibility of doing at least one inspection of each tower facility per quarter. If a problem occurs with an antenna in the Hazard Service Area, the Telecom Center dispatches its Hazard-based Technician to repair the problem. The sites are fully alarmed so that any problems can be detected remotely. Each of the antenna sites has an emergency generator with approximately two weeks of liquid propane (LP) gas to maintain operations in the event of a power outage.

The new mobile data communications systems that are to be installed in the trucks during 2003 as part of the STS software package implementation should actually be more efficient at receiving communications in poor reception areas, due to the fact that they will keep trying to reconnect on a regular basis and will do so automatically on the detection of a radio signal.

Work Management Systems

The Planning and Scheduling Process (PSP) system was implemented in the 1992-94 timeframe. It is a standard work management system (WMS) that assists in assigning the proper resources to work and scheduling it. PSP was developed in-house by AEP on a mainframe. It now has an Oracle database backend. It was originally used for all Distribution Line personnel. Currently it is used mostly by engineering, metering, and line departments. The management of each region can determine whether to use OPS or PSP for the engineering portion of the network design work. There is no automated link between PSP and OPS. The OPS system contains the original work request as entered by the Solutions Center. PSP is integrated with a PeopleSoft time and labor payroll system. Contractors use the PSP system for scheduling of work and closing out jobs but not for tracking crew hours.

The Compatible Units System (CUS) is integrated with PSP to enable the development of a time estimate for completing work. The number of hours is based on the number of hours that it would take one person to complete the work. Only the estimated labor hours, not the materials to be used on the specific job, are available from CUS. Local people match up the materials, vehicles, and resources required, then try to produce the best work schedule that they can for any given day. PSP maintains a backlog of work that can be designated for completion on a specific day. Crews fill out daily timesheets, which are then entered by an Administrative Assistant to close out the job. TDIS (estimating work order billing system) and CUS are used for producing the work orders.

Implementation of the STS software package is causing the phase-out of PSP. PSP will be phased out for the eastern regions by June/July of 2003. Severn Trent is being used in an attempt to implement one WMS for all parts of AEP. It is fourth generation software with more flexibility and more capability to manage the work projects. It is easier to develop interfaces to other software, which are frequently required. Severn Trent will also replace TDIS and CUS, but not OPS, as it is still part of the Customer Information System (CIS). There will be an interface between Severn Trent and OPS. It will not replace TERS. Severn Trent will be phased in over time due to the large number of systems that are being replaced.

The overall new system, which includes more than just the Severn Trent System, has:

- Storms (work management system)
- Auto-Scheduler (auto-routes the work directly to the truck and to schedule the crews)
- Spectrum (an internal mobile application that is an AEP project that will be integrated with Storms and Auto-Scheduler)

There will be direct interfaces from OPS to STS (and then to Auto-Scheduler). Then, based on the type of work, it can be routed to an SDS or directly to a Servicer. The job will go to an SDS if it is a construction project. It will go to a Servicer if it is a trouble job. STS also has the capability for the new project to go to an SDS (to do the field inspection) and then to an engineer in the area.

Spectrum will communicate with the trucks through an 800 MHz wireless system that use the existing towers and telecommunications network. In the case of an outage, the trouble report will be routed to the outage management system, then to the Storms system, and then to the Servicer's laptop in his truck. This will become the primary means of communication from the DDC to the Servicers. Laptops in the trucks will have geographic information system (GIS) and other mapping software, such as the IOWA software that is used for locating rural addresses and trouble spots.

Spectrum will be used for entering time and project completion information for Servicers into a mobile laptop unit. The construction crews will enter their time into the Spectrum system directly. AEP/Kentucky will be the first or second company in the east to go live on Spectrum.

The Operational Data Store is being developed as a way to produce required reports (other than standard reports) in the field offices using an ad hoc report writer. The system currently uses PowerBuilder for the reporting from the STS, but PowerBuilder is too complex for the average user. There are a significant number of standardized reports that are built into STS. For reports other than those, the users will go to the Operational Data Store.

B. Findings and Conclusions

Finding IV-1 Management of the Line Mechanics and Servicers is appropriate and adequate for the current staffing levels and workload.

The organization and the systems used to manage the Distribution Line field operations forces are consistent with the requirements for proper management and control of an organization of that size and responsibility. The spans of control that were observed were well within accepted standards for an electric utility distribution field operation. The systems and reports that were available as tools to the management of the operation were appropriate to support them in the performance of their assigned tasks.

Finding IV-2 The system used to communicate jobs to the Servicers is not comprehensive and requires the use of both the Spectrum System and hard copy printouts from the OPS application.

The currently used Spectrum system is incapable of receiving all of the work orders in an automated manner from OPS. The remainder of the work orders must be printed out in hard copy from OPS and manually transmitted to the Servicers. This results in duplication of some orders in the two communication methods and more opportunities for confusion or error. It is believed that the new Severn Trent system (which is scheduled for implementation in the first half of 2003) will resolve this problem.

Finding IV-3 The training that the Servicers were given in the use of laptop computers in their trucks and the associated software was inadequate and limits the benefits that AEP can gain from this technology.

Observation of the Servicers using their laptop computers and discussions with them revealed that training that had been given to them in the use of the units and the included software had not been sufficient to enable them to use the equipment to its maximum capability. It was stated that the training lasted for only one-half of a day and was not sufficient to allow the Servicers to become comfortable and familiar with their units. This was particularly deleterious due to the fact that several of the Servicers were not very familiar with computer technology in general.

Finding IV-4 The Servicers in the Hazard Service Area are working a large amount of overtime.

The large amount of overtime is attributable to the large number of after-hours callouts and a relatively small number of Servicers to handle the work load. The number of overtime hours charged on an annual basis for the period of 2000 through 2002 year-to-date is presented on *Exhibit IV-3*.

Exhibit IV-3
HSA Servicer Overtime Hours

Service Location	Year 2000	Year 2001	Year 2002 (as of 10/3/02)
Knott	565.3	703.1	674.9
Leslie	484.5	563.7	501.5
So. Perry	502.8	473.8	463.6
No. Perry	1,430.7	1,416.8	1,272.7
Breathitt	408.1	562.2	551.0
Whitesburg	539.5	734.9	675.3
Totals	**3,930.9**	**4,454.5**	**4,139.0**

Review of this data reveals that all of the Servicers in the HSA have been working significant quantities of overtime during this period. This is particularly true in the Perry County area, which includes the City of Hazard. Because this data reflects the number of hours that are paid for (rather than the number of hours that are actually worked), the numbers are somewhat inflated. However, even with this taken into consideration, the Servicers are still working very large amounts of overtime. When Servicers are working this much overtime, it would be expected that there would be a declining efficiency of the work as the number of hours worked increases. Additionally, at some point the number of hours worked becomes a concern relative to the safety of the workers. Having a larger number of Servicers assigned to the Hazard Service Area would serve to reduce the amount of overtime worked by each of the individual Servicers, thereby reducing concerns with work performance and safety. Moreover, a larger number of Servicers would be expected to cut down on the amount of time that it takes to restore service in a storm situation due to an enhanced ability to spread the workload across more field personnel.

Finding IV-5 The limited number of Servicers in the Hazard Service Area results in a reduced ability to restore service in a timely manner during storm situations.

With the service restoration jobs divided over a smaller number of Servicers, response time and times to restoration will be longer than if a larger contingent of Servicers were available. While there certainly are practical and economic limits to the number of Servicers that should be in place, the number that currently exists is smaller than would be needed to provide satisfactory restoration times. Additionally, when the Servicers are on vacation or out-of-town, the coverage of their responsibility often is transferred to a Line Mechanic. While the Line Mechanics have the technical capability to perform the required restoration work, their lack of daily familiarity with the tasks involved and with the geography of the area renders them less efficient than a Servicer would be in performing the same work. Additionally, situations were identified in which certain jobs or types of work were delayed until such time that the Servicer returned to duty.

Finding IV-6 The company needs to establish an easy method for tracking the number of hours that are actually spent on a callout job versus the number of hours that are paid for.

The Distribution Line organization managers currently have no mechanism or system for tracking the number of hours that Servicers actually spend on completing service restoration work. The only numbers that are recorded are the number of hours of overtime that are paid for. Because the Servicers are paid for a certain minimum number of hours for any call out, it is impossible to determine the actual number of hours spent on various service restoration and repair jobs. Additionally, the amount of travel time is not captured as a separate data item. There is a capability to distinguish between those overtime hours that are spent for routine work versus those that are spent for storm work. The availability of actual hours worked data would enable the Distribution Line organization managers to make better judgments concerning deploying their forces in storm situations and permit better performance tracking capability. Additionally, this data could also assist in the identification of those geographic areas that are in need of more coverage.

Finding IV-7 Significant radio communications dead spots that exist in two of the counties in the Hazard Service Area disrupt the ability of the field crews to communicate with the DDC and the Schedulers.

The current radio communications system does not provide adequate radio coverage in all areas of the HSA, leading to the presence of significant "dead spots" where radio communications between the field crews and Dispatchers is impossible. This is a significant concern due to crew efficiency and safety considerations. However, a plan is in place to resolve these communications problems by the year 2004 through the construction of several new antenna facilities.

Finding IV-8 Most of the outages that are repaired by the Servicers are caused by trees, particularly in the summer.

Interviews with several Servicers revealed that, in their collective opinion, trees are the single largest cause of outages experienced in the Hazard Service Area. This is particularly true in summer, because trees are in leaf and they have a greater tendency to fall or for branches to break off due to wind. This topic is covered in more detail in Chapter VI – Vegetation Management and Animal Protection.

Finding IV-9 The rights of way that have been obtained by AEP/Kentucky in the Hazard Service Area are not wide enough in many cases to adequately prevent tree-related damage.

Interviews with several of the Servicers revealed that, in their collective opinion, the insufficient width of many rights of way results in many of the service outages that they respond to. It was their opinion that widening the rights of way would eliminate a significant number of tree-caused outages. This topic is covered in more detail in Chapter VI – Vegetation Management and Animal Protection.

Finding IV-10 The Tree Condition Reports completed by the Servicers to report vegetation that needs to be trimmed are limited in their effectiveness by the inconsistency of response.

Tree Condition Reports (which are a form of the Abnormal Equipment Report) are used by Servicers and Line Mechanics to report those field conditions that they identify that require tree trimming to avoid future problems with outages. After the form is completed and submitted, it is directed to one of two places:

- For small trimming jobs it is directed to the SDS for the HSA, which uses an Asplundh crew assigned to the SDS to handle the required trimming work
- Larger jobs that require more trimming are directed to the AEP/Kentucky Vegetation Management organization for the HSA for completion

While the reports handled by the SDS are followed up on with the Servicer who submitted the report, this does not necessarily happen with the larger jobs that are transmitted to the Vegetation Management organization. As such, the Servicers often are not informed as to when the trimming work is completed. This lack of a feedback loop discourages the Servicers from using the report, rendering it less effective than it could be.

Finding IV-11 Inconsistencies have been observed in the reporting of the number of customers affected by an outage, depending on the source of the data.

Due to using different sources of data and information, some of the numbers reported to the Kentucky Public Service Commission (KPSC) related to the number of customers who were affected by recent outages were not consistent. Work is currently ongoing within AEP/Kentucky to standardize its data base in order to gain consistency and accuracy in the numbers reported.

Finding IV-12 The lack of a full version of the PowerOn software in the Hazard Service Center limits the availability of useful information, particularly in storm situations.

The currently installed remote version of the PowerOn software is quite limited in its capabilities to allow access to data that is important in storm restoration efforts or in daily operations. The ability to access this greater range of data would be particularly important in the event of a severe storm in the HSA, where control of the restoration effort was transferred from the Roanoke DDC to the Hazard Service Center.

Finding IV-13 The automated routing optimization capability that is built into the Small World software package is not being utilized, nor are the capabilities that would be presented by the installation of GPS units in the Servicer and Line Mechanics trucks.

As this routing optimization capability feature is already included in the Small World application, it would be desirable in the future to take advantage of the capabilities provided therein. Several other utilities have adopted an automated field force routing system combined with on-board GPS units with great success. Such a technological advance would certainly be expected to enhance the ability of the DDC to direct the field forces in an optimal manner.

Finding IV-14 The Materials Management function properly supports the operations of the field forces.

The Materials Management function is managed and operated in an appropriate manner to properly support the materials requirements of the field crews. The inventory management computer system adequately provides the data that is necessary to properly manage the inventory/stores function. Statistics related to the performance of the materials management function are collected and monitored to ensure that performance and productivity are meeting established targets.

Finding IV-15 The maintenance program for the substations is appropriate and consistent with industry standards.

Observations were performed of the normal maintenance activities at two of the HSA substations. The substations were both found to be very weed-free and neatly kept. It was obvious that the maintenance was being performed in a very efficient method. The records of the maintenance performed were very comprehensive and detailed, detailing each maintenance activity performed and all of the various readings taken during the scheduled maintenance activities. There do not appear to be any problems with the operation and maintenance of the substations.

Finding IV-16 The design and operation of the transmission system does not have a deleterious effect on reliability in the Hazard Service Area.

The transmission system is well designed and operated and is not a significant factor in the reliability problems that have been experienced in the Hazard Service Area. The problems that have been experienced are much more directly related to the distribution system. This is primarily because the height at which the transmission lines are strung is high enough to allow them to avoid the majority of problems that occur due to tree-related damage. The distribution lines, being positioned at a lower elevation, are much more susceptible to tree-related incidents. Additionally, transmission line rights of way are generally wider than those which exist for distribution lines.

Finding IV-17 The distribution and transmission dispatching functions are performed in a manner that is consistent with industry standards.

The operations of the Roanoke DDC were observed and found to be consistent with accepted industry standards. Centralization of the operation in Roanoke has strengthened the DDC's ability to respond to emergency situations. There is a significant emphasis placed on continually improving the dispatching process to provide better and more comprehensive support to the field crews.

C. Recommendations

Recommendation IV-1 Perform investigations to ensure that the new Severn Trent System software package has the capability to communicate all forms of jobs to the Servicers. (Refer to *Finding IV-2*).

To avoid limitations of the current system in relation to not being able to transmit all types of jobs to the Servicers, testing should be completed during the implementation and testing phase of this systems implementation project to verify this capability. The resolution of this problem should be confirmed prior to implementation of the system to avoid any future problems with this important system requirement.

Recommendation IV-2 Design the training program to be administered to the Servicers on the use of the new Severn Trent System in such a way as to ensure that the Servicers are able to avail themselves of the full capability of their laptop units and the software thereon. (Refer to *Finding IV-3*).

Without proper training of the use of the new and existing software, the Servicers will not be able to use the computerized tools to their greatest impact and benefit. The training programs that are conducted during the implementation phase of the project should be specifically focused on instilling this knowledge in the Servicers. It should also be considered that the Servicers have varying levels of experience and comfort with personal computers. Therefore the training programs must address these individual needs if it is to be successful.

Recommendation IV-3 **Evaluate the Servicer workload and outage restoration statistics to determine the optimal number of Servicers that should be on staff in the Hazard Service Area. (Refer to *Finding IV-4* and *Finding IV-5*).**

It is very probable that the results of this evaluation will identify a need to increase the number of Servicers in the HSA. Increasing the number of HSA Servicers will have two very beneficial effects:

- The amount of overtime that is being worked by the individual Servicers should be reduced.
- The ability to respond to outage situations in a timely manner should be enhanced.

With a larger pool of trained and equipped employees, the workload related to service restoration would be shared over a larger number of people, thereby improving the efficiency and timeliness of the restoration process. Please note that this finding is very similar to one which is found in Chapter III – Asst Management.

Recommendation IV-4 **Develop a software application that would allow the Distribution Line managers to track and monitor the number of overtime hours that are actually worked as opposed to those which are paid for. (Refer to *Finding IV-6*).**

The availability of this actual hours worked data would enable the Distribution Line organization managers to make better judgments concerning deploying their forces in storm situations and permit better performance tracking capability.

Recommendation IV-5 **Continue with the established plan to improve the radio communications network in the Hazard Service Area (Refer to *Finding IV-7*).**

This improved radio communications capability should resolve the existent problems with poor radio communication capability in the HSA. This improved capability should, in turn, result in the Servicers and field crews becoming more efficient and safer.

Recommendation IV-6 **Review the current policy on rights of way to determine if improvements could be made that would have a beneficial impact on service reliability in the Hazard Service Area. (Refer to *Finding IV-9*).**

Upon completion of this review, if it is determined that significant benefits can be achieved through modifying the current policy on rights of way, this issue should be addressed by the management of AEP/Kentucky as a means of improving service reliability. The management of AEP/Kentucky should take a more aggressive stance in regard to attempting to obtain permission to increase the width of its rights of way in those situations where the current right of way is insufficient or has created problems in the past. This topic is covered in more detail in *Chapter V – Vegetation Management and Animal Protection* of this report.

Recommendation IV-7 **Develop and implement a feedback mechanism to inform the Servicers and field crews of the status of the Tree Condition Reports that they have submitted. (Refer to *Finding IV-10*).**

By implementing such a feedback loop, the Servicers will be better informed as to the status of the requested work and will be more encouraged to use the Tree Condition Reports for their intended purpose, thereby obviating potential problems before they can impact service reliability.

Recommendation IV-8 **Continue the efforts that have been undertaken to improve the quality and consistency of the data that is reported to the KPSC. (Refer to *Finding IV-11*).**

These efforts should result in more viable and accurate numbers being reported as bad data is being eliminated from the databases and the data is being consolidated into one data set.

Recommendation IV-9 **Implement a full version of the PowerOn software in the Hazard Service Center for use in daily operations and storm restoration activities. (Refer to *Finding IV-12*).**

A full version (as opposed to the remote version that is currently in place) of the PowerOn software should be implemented and will result in much greater localized information and capability. This will be particularly important in the event of a major storm restoration effort that is managed from the Hazard Service Center.

Recommendation IV-10 **Review the potential for utilizing the automated field crew routing optimization capability that is built into the Small World software application. (Refer to *Finding IV-13*).**

As this routing optimization capability feature is already included in the Small World application, it would be desirable in the future to take advantage of the capabilities provided therein. Several other utilities have adopted an automated field force routing system combined with on-board GPS units with great success. Such a technological advance would certainly be expected to enhance the ability of the DDC to direct the field forces in an optimal manner.

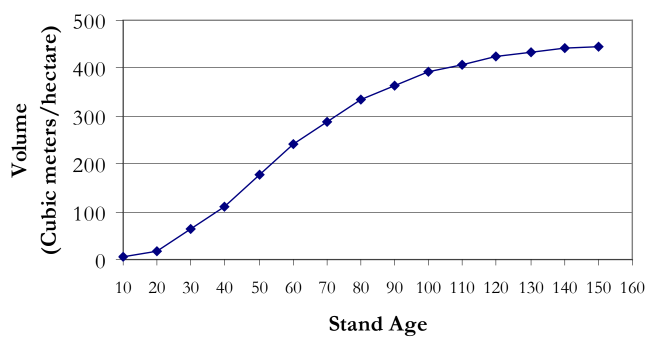
V. Vegetation Management and Animal Protection

This chapter addresses American Electric Power (AEP)/Kentucky's vegetation management and animal protection activities. Vegetation management is critical in providing reliable service to the customer. Tree-conductor contacts are the largest cause of unplanned service interruptions. AEP/Kentucky electric lines have a high exposure to trees. Animal-caused service interruptions, while not substantial, erode the quality of electric service and necessitate the installation of protective equipment.

A. Vegetation Management Concepts and Principles

The inventory of all trees that either have the potential to grow into a power line or on failure (breakage) to strike a conductor will be referred to as the utility forest. The utility forest has the same characteristics as any forest. The same patterns of biomass addition (tree growth) and tree mortality apply. Both of these are significant factors in power line security and both can be mathematically represented by geometric progressions, as illustrated in *Exhibit V-1*.

Exhibit V-1
Forest Biomass Addition
Timber Production
Spruce on Good Site



Adapted from: Freedman, Bill and Todd Keith, 1995. Planting Trees for Carbon Credits. Tree Canada Foundation.
1 cubic meter = 35.3 cubic feet.; 1 hectare = 2.47 acres

From a utility perspective, trees represent a liability in both the legal and financial sense. The fact that the utility forest changes by geometric progression is significant. It means the tree liability, if not managed, will grow exponentially.

Trees cause service interruptions by growing into energized conductors and establishing either a phase-to-phase or phase-to-ground fault. Trees also disrupt service when trees or branches fail, striking the line causing phase-to-phase faults, phase-to-ground faults or breaking the continuity of the circuit. As it is the two factors responsible for vegetation-related service interruptions, tree growth (biomass addition) and tree mortality, change by geometric progressions, the progression of tree-related outages is exponential. Failure to manage the tree liability leads to both exponentially expanding future costs and tree-related outages. Conversely, it is possible to simultaneously minimize vegetation management costs and tree-related outages.

It is not possible to totally eliminate the tree liability because the process of succession is a constant force for the re-establishment of trees from whence they were removed. The tree liability then, is like a debt that can never be completely paid. Under such circumstances, the best economy is found in maintaining the debt at the minimum level, thereby minimizing the annual accrued interest. However, irrespective of cost, minimizing the size of the tree liability or utility forest is rarely an option for utilities due to multiple stakeholders with an interest in the trees. What can be achieved, however, is equilibrium. The tree liability can be held constant at a point by annually addressing the workload increment. To continue the debt analogy, a debt is stabilized when the annual payments equal the interest that accrues through the year. The interest equivalent in the utility forest is comprised of annual tree growth and mortality. Actions that parallel the reduction in the debt principal are actions that actually decrease the number of trees in the utility forest. Such actions include removal of trees and brush by cutting or herbicide use.

When the pruning cycle removes the annual growth increment and the danger tree program removes trees as they become decadent, tree-related outages are stabilized. The residual level of tree-related outages reflects the interaction of several characteristics, including the size of the utility forest, chosen maintenance standards (such clear width), tree-conductor clearance, and tree species characteristics (such as mode of failure and decay). An expression of a managed tree liability, one where the annual workload increment is removed, is stable tree-related outages. Reducing tree-related outages below an achieved equilibrium necessitates actions that decrease the size of the utility forest. Actions are not limited to vegetation management. For example, increasing conductor height reduces the size of the utility forest as it reduces the number of trees capable of striking the line.

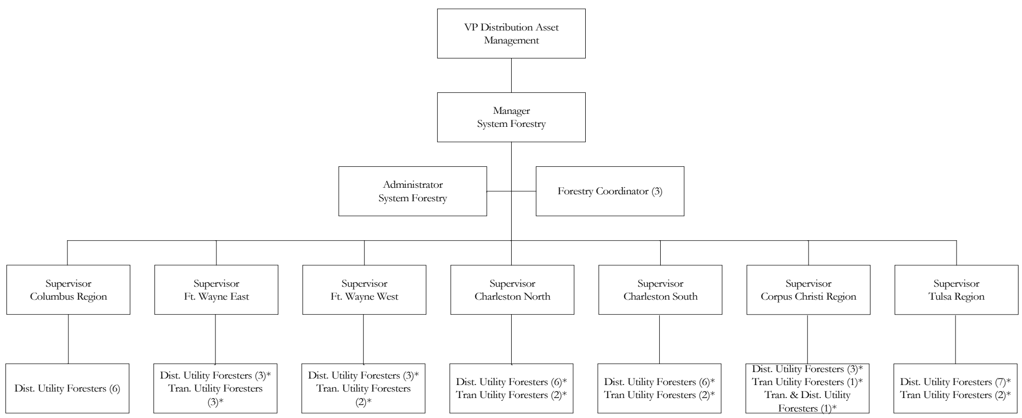
B. Background and Perspective

Organization

AEP's System Forestry (AEP Forestry) organization, which reports to the VP Distribution Asset Management, holds responsibility for vegetation management. Two foresters provide vegetation management services in the Hazard Service Area, one for the distribution system (Distribution Utility Forester) and another for the transmission system (Transmission Utility Forester). The Regional

Forester in the Charleston North Region supervises these foresters. The organization is shown in *Exhibit V-2*.

Exhibit V-2
AEP System Forestry Organization



* Resources located across each region

The System Forestry group was centralized in a 2000 reorganization stemming from a company merger.

Facilities

The distribution system is comprised of lines operated at 12 kV and 34.5 kV. The transmission voltages in the Hazard Service Area are 69 kV, 138 kV and 161 kV. Target easements are 40 feet for 12 kV lines, 50 feet for 34.5 kV lines and generally, 100 feet for the 69 kV, 138 kV, and 161 kV transmission lines. The target easements are not always achieved for distribution lines.

Clearance Standards

Trees that require pruning are cut to provide a minimum of 10 feet of clearance between conductors and the nearest tree part. Overhangs, however, are not tolerated regardless of clearance. Re-clearing is done to re-establish the original right-of-way. Where a transition from brush to large trees is evident, it is assumed that the large trees delineate the easement. Where no clear transition exists, vegetation management work planners and AEP Forestry staff assume the general easement widths, unless there is a known history with the landowner indicating otherwise. There is no set clear width (side clearance from tree boles at the right-of-way edge to the nearest conductor). There is no set distance for danger trees (trees outside the right-of-way that are diseased, cracked, leaning, subject to uprooting, or because of structural defects pose a threat to the power line). Identification of and removal of danger trees is based on whether or not they could strike the line on failure.

The right-of-way width and the conductor the furthest from the right-of-way centerline generally determine the clear width. For example, the clear width on 34.5 kV can be calculated as 21 feet (50 feet/2 – 8 feet (cross arm)/2 = 21 feet).

The clear width is considered when lines traverse slopes. The line may be installed off-center to provide a greater width on the uphill side. The clear width may be increased where the incidence of disease forces the labeling of an entire stand as danger trees. AEP/Kentucky is currently faced with increased pine mortality due to a bark beetle infestation.

Work Planning

The Distribution Utility Forester compiles the "wish list" of work for the following year considering:

- Follow up required such as herbicide on areas recently cleared
- Forecast of trim and re-clear based on history, visual field inspection, concerns expressed regarding reliability, and the number of customers on the circuit
- The list is prioritized based on engineering and operations input
- The Regional Forester checks to ensure the proposed work addresses lines that have the lowest reliability

The work plan may be modified through the year by input from operations, which is obtained on a weekly basis via the Complaints Database teleconference. Operations is another point of input regarding reliability. Other factors that may necessitate modifying the work plan include:

- New capital work projects
- The lack of availability or availability of specific crew types may alter the timing of work plan elements (i.e. aerial saw; aerial spray crew)
- Response to the Kentucky Public Service Commission (KPSC)
- Strikes
- Unusual events like 9/11, which prevented any flying, grounding the aerial work crews
- Hotspotting (where trees are in contact with conductors or the evidence of recent contact exists; addressing unplanned work as the need arises) done in response to Operations requests

Planning of the actual field work is done through contract work planners. The work planners are Asplundh Tree Expert Company (Asplundh) employees. The work planner position falls between a crew foreman and a general foreman.

In urban areas the work planner identifies the work to be done and notifies the landowner. Where the work is cross-country, the work planner notifies the landowners and the crew foreman determines the work to be done based on clearance requirements and general guidelines. The work planners mark the work on "pole maps." Upon completion of the work, the maps are returned to the Utility Forester. The circuits are then marked as completed in Right of Way Management (RWM), a web-based invoicing and record keeping database. There is no vegetation management layer in the Small World. As a result, records that tie work completed to geographic locations exist on paper only.

Utility Foresters audit the work for compliance with guidelines, completeness, quality, and accuracy of work units reported. All levels of AEP's Forestry group have specific audit frequency targets. When Forestry staff is particularly busy, the targeted amount of audits may not be met.

Hotspotting

Utilities commonly handle hotspot (where trees are making conductor contact) locations with a work effort separate from routine maintenance work. Such off-cycle work is generally referred to as hotspotting. There is a focused effort to minimize hotspotting due to associated higher unit costs. That hotspotting costs are frequently more than 100% higher than routine cycle pruning costs is illustrated in the Circuit Cost Summary report provided through AEP's RWM system. To facilitate the management of the amount of off-cycle work, hotspotting is listed as a separate line item in the budget and such work is tracked separately in RWM. *Exhibit V-3* provides the history of hotspotting in the Hazard Service Area.

Exhibit V-3
Hazard Service Area Hotspot History
(Distribution Only)

Year	Staff Hours	Cost
1997	25,103	$420,000
1998	8,673	$150,000
1999	14,104	$283,699
2000	21,250	$432,983
2001	6,311	$158,211
2002	NA	$120,462

Maintenance Cycles

Pruning cycles vary between two to three years in urban areas and three to eight years in rural areas. The pruning cycle is derived from the combination of the local Utility Forester's expertise, budget available, and emerging priorities. No growth studies have been undertaken by AEP/Kentucky to guide the derivation of maintenance cycles.

Pruning, tree and brush removal, and the identification and removal of danger trees are generally done in the same maintenance action. Exceptions occur for operations such as aerial pruning and danger tree removals in response to pest infestations. Aerial pruning is a discrete operation because the equipment requirements are completely different from that used for manual pruning and re-clearing. The Hazard Service Area is currently facing a Southern pine bark beetle epidemic that has resulted in stands of dead or decadent pines necessitating a more immediate, separate danger tree response.

Generally, within any utility pruning program, there are locations where trees will contact conductors before the next maintenance operation. Within the Hazard Service Area, locations where trees exist that grow considerably faster than the average (referred to as cycle busters), are targeted for tree replacement. Cycle buster species in the Hazard Service Area are silver maple (*Acer saccharinum*) and box elder (*Acer negundo*).

The herbicide program is planned as a follow up to cutting treatment, one to two years after re-clearing. While the first herbicide application following re-clearing is perceived to greatly diminish the stem count of incompatible species, subsequent herbicide applications are planned on a three-year cycle. The need for the herbicide application is monitored and the timing may be adjusted as required. AEP/Kentucky foresters indicated it is their experience that after multiple herbicide applications the cycle length is extended due to biological competition from low-growing power line compatible vegetation.

Tree Removals

AEP's *System Forestry Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations* document establishes a focus on tree removals unless the cost of such removals exceeds the cost of three pruning events. The guideline derives from financial analysis performed by Oklahoma Public Service.

The utility foresters exert influence on the work planners to ensure a strong focus on obtaining tree removals. *Exhibit V-4* provides the percent of total trees handled that are removed. The information is provided for the Hazard Service Area and AEP/Kentucky.

Exhibit V-4
Trees Removed of Trees Handled (Distribution Only)

	Hazard Service Area			AEP/Kentucky		
Year	Tree Trimming	Tree Removal	% Removals	Tree Trimming	Tree Removal	% Removals
1998	6,642	19,629	75%	53,078	63,959	55%
1999	9,630	33,658	78%	25,824	43,370	63%
2000	18,447*	33,622	65%	38,708	66,050	63%
2001	9,770	24,803	72%	23,579	47,988	67%
2002	7,035	16,894	71%	15,257	42,489	74%

* Aerial saw accounted for 10,880 trims

AEP Forestry has a tree replacement program that focuses on obtaining landowner agreement to remove cycle buster trees and replace them with low-growing, power line compatible tree species. Tree replacement is a separate line item in the budget. A financial analysis was undertaken to establish the merits of a tree replacement program.

Contracting

AEP has entered into an alliance agreement with Asplundh Tree Expert Company. The contract is essentially a sole source agreement with the exclusion of work performed from aircraft.

This contract that American Electric Power has entered into with Asplundh was piloted in American Electric Power's Charleston region. The agreement guarantees American Electric Power a specific minimum cost saving. At a certain percentage gain in productivity a pool of savings is triggered. In AEP/Kentucky the minimum guaranteed saving is 1% and the incentive pool begins to accumulate when productivity gains exceed 3%. The contractor is rewarded from the accumulated pool of savings based on key performance indicators, including productivity, safety, reliability, and mileage completed. In so far as the contractor fails to meet the conditions for the maximum incentive payment, the residual pool funds comprise further savings for American Electric Power.

Under the Alliance, AEP shares reports and information with Asplundh, and Asplundh has shared information with AEP. The Regional Forester believes the contractor has been more responsive under this contract. The contractor is free to adjust crew staffing and equipment because they need to meet certain productivity goals. The Regional Forester perceives specific benefits to arise from the Alliance. There is more stability in the work force because of the duration of the contract. This results in crew personnel being more experienced and familiar with the geographic area.

Productivity

Most of the vegetation management contract work is done on an hourly rate basis. Unit costs are derived from the RWM database/reporting system. Under the Alliance contract productivity information is shared with the contractor to focus improvement efforts that benefit both parties.

Budget

The budget determines the amount of tree work that can be completed. Local forestry staff develops a work plan based on their assessment of the work required in the following year. Funding is never sufficient to cover the locally perceived needs. A process of prioritizing what work will be done with the allocated resources is initiated by consulting the local Operations group and the Regional Forester. The Regional Forester has some flexibility in shifting funds to areas that have a particular need requiring resolution.

Exhibit V-5 provides a 6-year history of vegetation management funding both for the Hazard Service Area and AEP/Kentucky as a whole. The Hazard Service Area, since 1997, has received an increased share of the total AEP/Kentucky vegetation management budget.

Exhibit V-5
Vegetation Management Funding

Year	Hazard Whitesburg	% Change Relative to 1997	AEP/Kentucky	% Change Relative to 1997	Hazard Share of Total KY VM Budget
1997	$1,147,818		$4,099,999		28.00%
1998	$1,286,226	12.06%	$3,962,200	-3.36%	32.46%
1999	$1,367,653	19.15%	$3,088,468	-24.67%	44.28%
2000	$1,199,005	4.46%	$2,985,748	-27.18%	40.16%
2001	$1,109,587	-3.33%	$2,846,632	-30.57%	38.98%
2002	$1,152,638	0.42%	$3,202,100	-21.90%	36.00%

Decision Support

There is no inventory of the vegetation management work that needs to be done on an annual basis. Nor are there growth studies to guide the derivation of average pruning cycle lengths based on established clearance and tree re-growth rates.

Asset management approaches are used to prioritize where the largest return in reliability can be obtained for the dollar invested.

Productivity and mileage completed are key performance indicators in the Alliance contract. These are tracked in RWM, which provides both standardized reports and offers the flexibility for ad hoc reports. RWM provides unit costs, work units, herbicide usage, etc. from the foreman and circuit level up to the system level.

Animal Control

Birds and animals accounted for about 1% of unplanned outages in the Hazard Service Area over 1999-2001.

Targeting locations identified as experiencing animal caused outages, animal guards are installed on the primary bushings of overhead line transformers and other line equipment. In 2002 the installation of 217 animal guards at a cost of $3,348 is planned for the Hazard Service Area.

C. Findings and Conclusions

Finding V-1 Tree-caused outages are a distribution issue not a transmission issue.

The transmission system is not tree-free and some outages attributable to trees do occur, however, the number is very small. As shown in *Exhibit V-6*, the number of tree-caused outage incidents on distribution lines is substantially higher than those experienced on the transmission system.

Exhibit V-6
Tree-Related Outage Incidents - Hazard and Whitesburg

Cause Code	Years	Distribution Interruptions	Transmission Interruptions
Tree Inside ROW	1997-2001	1515	6
Tree Out of ROW	1997-2001	1806	0
Tree Removal	1997-2001	293	1
Total		**3614**	**7**

Finding V-2 Vegetation management methods, as employed, minimize both current and future vegetation management costs.

The vegetation management program as understood at the regional and local level has the potential to minimize both current and future maintenance costs. There is a strong, successful focus on tree removals. The rate of tree removal for AEP/Kentucky is much higher than is typical in the utility vegetation management industry. The high removal rate is particularly true for the Hazard Service Area (*Exhibit V-4*). From 1998 to present, in the Hazard Service Area, 71% of all trees handled were removed. This industry leading result will reduce future costs by avoiding the repetitive costs of pruning. The exceptional removal rate record is, however, marred. It is not known to what extent the high removal rate is an artifact of not handling the pruned trees often enough.

Some of the high removal rate may be attributable to the fact that the AEP/Kentucky service area is heavily treed and, under such conditions of tree abundance instead of scarcity, landowners may place less value on trees. Regardless, tree removals are not obtained without a focused effort to address the issue with landowners.

Pruning quality in the Hazard Service Area is very good. Pruning quality has a major impact on the rate of regrowth and, thereby, on the pruning maintenance cycle length and costs. Pruning quality is so good that there is no opportunity to further increase cycle length or suppress regrowth.

Herbicides are widely and effectively used in the AEP/Kentucky vegetation management program. Timely herbicide applications reduce current maintenance costs but, more significantly, by reducing the stem density of incompatible species while fostering a power line compatible vegetation community, substantially reduce future maintenance costs. Acceptance of herbicide use by landowners is high with only about a 3% refusal rate.

AEP/Kentucky's use of aerial spraying and aerial pruning are effective and serve to reduce maintenance costs.

AEP's prescriptive approach to vegetation management generally demonstrates a high level of professional skill and produces excellent results. This is particularly true for timely right-of-way interventions.

Finding V-3 The sole source Vegetation Management Alliance Agreement guarantees immediate savings benefits but sacrifices the ability to ascertain whether productivity and costs are competitive.

While the structure of the Alliance Agreement benefits American Electric Power, in entering into a sole source supplier agreement American Electric Power gives up the possibility of competitive contractor comparisons. If such comparisons were made in advance of entering into the Alliance Agreement and were the basis for selecting the contractor, then the process of ongoing monitoring of productivity is both informative and adequate.

Finding V-4 Maintenance cycles are too long and the timing of vegetation management activities is too late to avoid service interruptions from right-of-way trees.

Field examination of circuits where work is being done in the current (2002) year and where work is planned for next (2003) year revealed numerous locations where trees were either in the conductors or burning on the vegetation indicated that tree branches had made conductor contact. While no quantitative measure of the number of hotspots was undertaken, Schumaker & Company consultants found it not uncommon to encounter as many as five or six hotspots per mile of line.
Schumaker & Company consultants also found that work planned for 2004 includes locations where the clearance between trees and conductors is inadequate to avoid burners occurring prior to pruning service delivery.

While it is agreed that a two to three year pruning cycle in urban areas might be expected to prevent trees from growing into conductors, there was insufficient detail in the AEP/Kentucky data records to definitively assess whether the two to three year cycle is being met. Based on the total 2499 miles of distribution line in the Hazard Service Area, a three year pruning cycle necessitates covering 833 miles per year. The AEP *Forestry 2002 Distribution Work Plan – Pikeville/Hazard* shows 233 miles of cutting work planned for the Hazard Service Area. The planned miles fall substantially short of the 833 miles required to achieve a 3 year pruning cycle.

There is one standard clearance obtained when pruning. It is 10 feet. Hence, there should be no difference in the length of the pruning cycle for urban and rural areas, unless tree species are vastly different or no tall-maturing trees are tolerated on the right-of-way in rural areas. It was observed by Schumaker & Company consultants that planted landscape trees did introduce some non-native species but most trees were naturally occurring, volunteer species. If tall-maturing trees were not tolerated in the right-of-way, then all growth requiring pruning would arise from lateral growth. A pruning cycle of three to eight years for lateral growth would be adequate to avoid conductor contact. AEP/Kentucky is quite successful in obtaining tree removals, concentrating trees requiring pruning to the vicinity of residences. In the Hazard Service Area, however, a large portion of the residences is in rural areas. Because people value trees, they resist removal of trees around residences. This has the effect of interjecting a shorter pruning cycle (two to three years) into the three to eight year rural maintenance cycle.

Other than the fact of different vertical and lateral growth rates, one might justify the different cycle lengths between urban and rural settings on the basis of human exposure to electrical hazards potential but not from a reliability perspective.

The implications of the high number of burners evident in current and next year planned work areas are that either AEP/Kentucky will need to use more costly hotspotting or customers must endure service interruptions.

Schumaker & Company consultants observed an herbicide application being made to dense and tall brush, ranging up to 25 feet in height. It was estimated by local forestry staff that the area had been cleared six years ago. However, this estimate suggests in excess of four feet of growth per year on yellow poplar (*Liriodendron tulipifera*). Both the density and height of the brush serve to drive up maintenance costs. Generally, the ideal timing for the herbicide application that both minimizes costs and optimizes efficacy of effecting a right-of-way species shift to power line compatible species will be one or two years after brush cutting.

Finding V-5 Because maintenance cycles are too long, the need for hotspotting is great, yet the use of hotspotting to maintain uninterrupted service is being constrained.

The extent of the need for hotspotting to maintain safe, reliable service is a reflection on the adequacy of the maintenance cycle.

AEP/Kentucky's use of hotspotting has been variable over the years of 1997 through 2002 (*Exhibit V-3*). Expenditures on hotspotting appear to be substantially higher than average every third year. Both the number of hotspots witnessed during the field tours and the increasing number of service interruptions arising from right-of-way trees (*Exhibit V-8*) indicates that, unless maintenance cycles are adjusted, there will be a need for a large expenditure hotspotting program in 2003.

From a financial perspective there is merit to minimizing hotspotting. This is recognized by AEP Forestry and hence, hotspotting is minimized. The recognition and intent are positive. However, the purpose of a hotspotting program is to address the safety and reliability problems associated with tree-conductor contacts arising between maintenance cycles. The product of overly long pruning cycles is the increased need for hotspotting. The way to minimize hotspotting without increasing unit costs or tree-related outages is via a pruning cycle based on standard clearance and tree growth rates. The combination of overly long pruning cycles and the minimization of hotspotting expenditures finds expression in higher rates of tree-caused service interruptions.

Finding V-6 Use of industry standard practices inadequately address the reliability risks associated with the very high extent of tree exposure.

AEP/Kentucky's service area has an extremely high concentration of trees. Much of the area is rural and the topography mountainous. As a result power lines run not alongside roads but cross-country, doubling the amount of tree exposure.

The extent of tree exposure and remote, rugged terrain impose a serious challenge to managing service reliability. Vegetation management practices used are typical of the utility vegetation management industry and, thereby, fail to recognize the abnormally high degree of tree risk.

Specifically, AEP/Kentucky's practices regarding the identification and removal of danger trees are typical of the utility vegetation management industry. With the exception of trees affected by a pest or pathogen, trees susceptible to failure and interfering with electrical service (danger trees) are generally identified and removed only during the routine maintenance cycle. The inadequacy of this approach is illustrated by the fact that failure of off right-of-way trees accounts for about 35% of the total hours of unplanned distribution service interruptions (*Exhibit V-9*).

AEP/Kentucky has a very high tree removal rate. While this record bodes well for reducing off right-of-way tree-caused outages, the benefits are obscured by the negative effects of an overly long maintenance cycle. However, while a reduced cycle length would contribute to improved service reliability, off right-of-way tree-caused outages will remain relatively high being positively correlated to the extent of tree exposure. The practices and strategies applied are designed to identify and mitigate against tree hazards but not to limit the extent of tree exposure.

The observed vegetation management practices and articulated strategies do not reflect recognition of the rates of, and influence of, innate tree mortality.

Finding V-7 The vegetation management workload, comprised of the inventory of trees, tree growth, and mortality rates, has not been quantified and is unknown.

The first requirement to successfully managing tree-conductor conflicts is to quantify the magnitude of the problem. AEP/Kentucky has not done so.

Determining the size of the tree liability requires an assessment of the size of the utility forest (all trees capable of contacting conductors) and its rate of change. Through a count of trees categorized by work type (i.e. trims or removals), a measure of brush and total tree exposure, determination of average annual growth and mortality rates, the annual amount of work necessary to hold the tree liability steady is derived. Without a measure of the annual vegetation management workload increment required to sustain the tree liability at equilibrium, the probability of successfully managing tree-related outages is virtually nonexistent.

Finding V-8 The vegetation management budget is not based on the annual work required to avoid service interruptions.

While it was stated by AEP management that vegetation management funding has been relatively stable, actual expenditures show a downward bias lacking cost of living increases (*Exhibit V-5*). The trend for decreasing maintenance spending is apparent in the AEP/Kentucky vegetation management budget, which was reduced by 30% in 2001 from 1997 levels. The Hazard and Whitesburg operating areas have to an extent been buffered from this decrease by receiving an increasing share of decreasing vegetation management funding for AEP/Kentucky as a whole. In the context of a shrinking funding allotment the Hazard Service Area cannot continue to receive an increasing share of these funds unless the need for vegetation management funds in the rest of the AEP/Kentucky service area is rapidly shrinking. If this is the case, then evidence for it should exist in substantial reductions in tree-related outages for the rest of AEP/Kentucky. Without evidence of a decreasing need for vegetation management outside the Hazard Service Area, one would expect over time the historical average share of funding to be reestablished. In the return to the average, the Hazard Service Area would have to absorb its share of vegetation management budget reductions.

AEP/Kentucky's funding of vegetation management is not based on any measure of tree workload. Successful long-term vegetation management requires funding that permits removal of, as a minimum, the annual workload increment. Failing that, tree-related outages increase.

The pruning cycle afforded by the current budget is disconnected from the biological facts. It is easy to ignore these facts in the absence of scientifically sound, established tree growth rates.

Any approach to budgeting for vegetation management that is based not first and foremost on actual tree volumes and conditions, lacks the logical underpinnings for effective long-term management.

Finding V-9 Applying asset management strategies to prioritize maintenance reduces maintenance costs but does not ensure improved electric system reliability.

Asset management strategies are useful for prioritizing where to allocate resources for the maximum reliability benefit. These strategies are separate from the total resources allocated and, therefore, do not ensure the delivery of any specific standard of service.

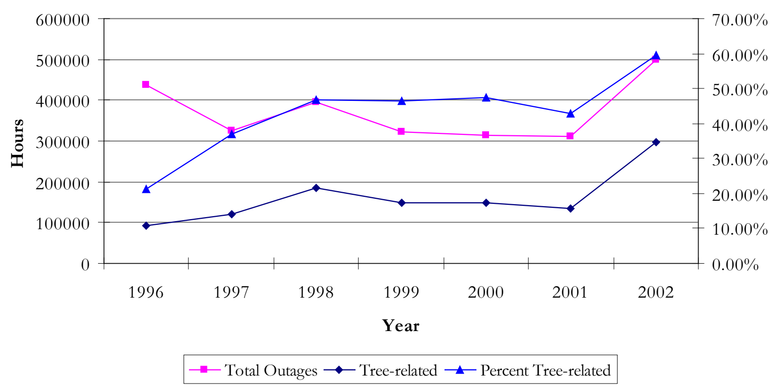
Asset management strategies as applied to vegetation management assure the optimum benefit for the dollar expensed and that may include getting more work done within the budget. For the approach to effectively address reliability problems there must be enough funds to complete as a minimum, the annual workload increment. That level of work completion would hold tree-related outages steady.

When funding for vegetation management is constrained such that the annual workload increment cannot be completed, system reliability will deteriorate. Asset management approaches may ameliorate the rate of deterioration but not the overall trend.

Finding V-10 Tree-related outages, the largest cause of unplanned service interruptions, are on an increasing trend that is not being addressed.

In the Hazard Service Area, tree-related outages are the single largest cause of unplanned outages. Over the period of 1998 to 2001 tree-related outages have accounted for 40% to 50% of all outages (*Exhibit V-7*) on a customer hour basis. Pro-rating the 2002 experience produces a jump to 60% of all outages.

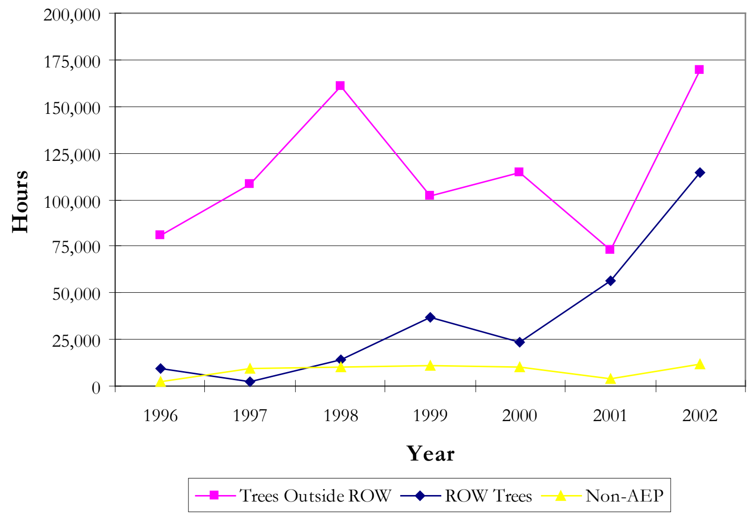
Exhibit V-7
Hazard Service Area
Unplanned Distribution Outages
(Major Storms Excluded)



* 2002 pro-rated

The outage history indicates that customers have been enduring more hours of service disruptions arising from on right-of-way of trees, which are trees requiring pruning. Within right of way tree-caused outages have been increasing essentially exponentially since 1997 (*Exhibit V-8*).

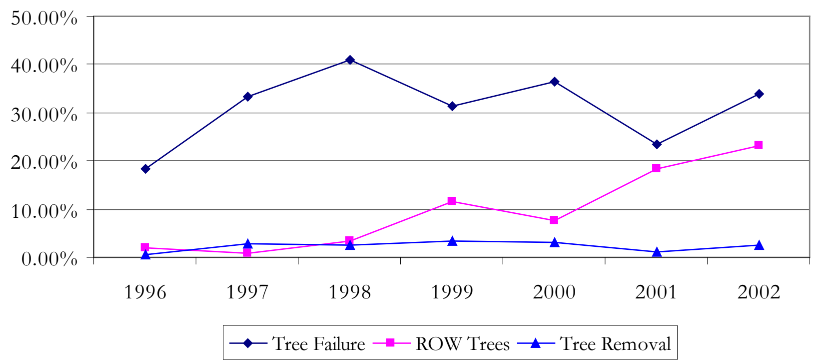
Exhibit V-8
Tree-Related Outages
by Tree Cause Code (Distribution)



* 2002 pro-rated

Right-of-way trees, which in 1997 accounted for less than 1% of unplanned outage hours, are predicted to account for more than 23% in 2002 (*Exhibit V-9*). Tree-caused outages due to non-AEP contractors have been fairly level. Tree failure of off right-of-way trees is the largest cause of service interruptions, ranging between 25% and 40% of all outages (*Exhibit V-9*). Tree removals in the Hazard Service Area were lower in 2001 than the preceding two years (*Exhibit V-4*). While data for 2002 is incomplete, pro-rating the trend found in the first 8 months suggests off right-of-way tree-related outages are increasing (*Exhibit V-8* and *Exhibit V-9*).

Exhibit V-9
Tree-related Outage Hours as a % of Total Unplanned Outages
(ROW Trees An Expanding Problem)

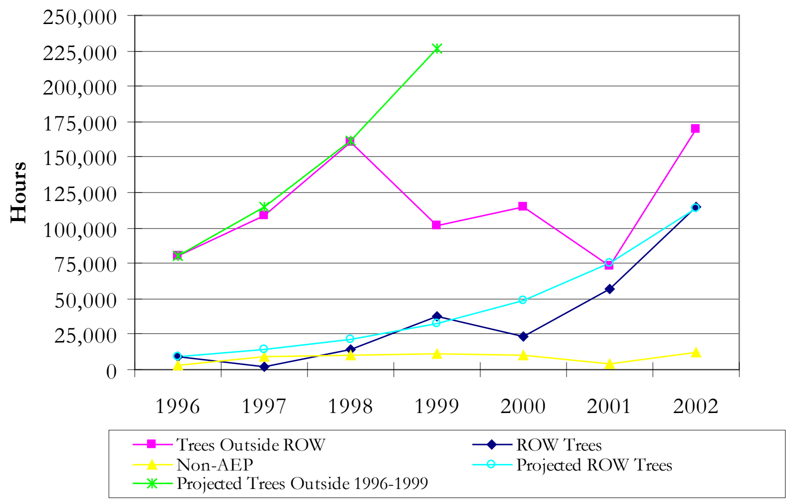


* 2002 pro-rated

The possibility exists that the influence of trees on reliability is not fully represented by the tree-caused outage codes. According to AEP/Kentucky documents another 6% of outages are ascribed to weather. AEP/Kentucky indicates that weather-related outages are mostly related to high wind and probably vegetation.

Tree-related outages caused by within right-of-way trees have been increasing exponentially since 1997 (*Exhibit V-10*). There is nothing in the vegetation management plan that would suggest this trend would change. The budget has not been increased to achieve a shorter pruning cycle and constrained hotspotting will contribute to perpetuate the established trend.

Exhibit V-10
Exponential Increase in ROW Tree-Caused Outages



* 2002 pro-rated

The focus on removals appears to have resulted in slight improvement in outages arising from off right-of-way trees until the current year. Both the (pro-rated) increase from 2001 to 2002 and the rate of increase from 1996 through 1998 show trees outside the right-of-way have the potential to add quickly and significantly to outages (*Exhibit V-10*).

To illustrate the potential for a rapid increase in tree-related outages from trees outside the right of way an algorithm was used to predict what those outages would have been for 1999 (Projected Trees Outside 1996-1999 in *Exhibit V-10*). The fact that the projected outages did not occur may be due to a lower frequency or intensity of minor storms and/or some action that proved to be an intervention. The intervention most probably was the over 70% increase in the rate of tree removals from 1998 to 1999 (*Exhibit V-4*). The nature of tree workload and tree-caused outage progression was revealed at the start of this section in *Vegetation Management Concepts and Principles* and illustrated in *Exhibit V-1*. Obtaining the best fit of such a geometric progression to the outage statistics for the years 1996 through 1998, the progression was extended for another year to forecast 1999 trees outside the right of way caused outages. While the projected level of outages did not occur, the projected curve (Projected Trees Outside 1996-1999 in *Exhibit V-10*) is revealing. Given we know the overall shape of the progression (as in *Exhibit V-1*), the projected outages segment reveals:

1) Work volume is well out to the right side of the graphic representation of the progression (see Exhibit V-1) where the exponential effects are large. This is to be expected because of the high degree of tree exposure for lines in the Hazard Service Area.
2) The rate of compounding is large as indicated by steepness of the slope for Projected Trees Outside 1996-1999. The steep slope is reflection of the degree of tree exposure but also provides information about tree failure rates, suggesting either high tree mortality or decadence and/or poor root support.

In a nutshell, what the Projected Trees Outside 1996-1999 curve reveals is trees outside the right of way caused outages are volatile, with a potential to significantly negatively impact overall reliability if there is not a focused management effort to contain them. Conversely, they are also very responsive to certain management actions (see sharp drop in Trees Outside ROW from 1998 to 1999 in *Exhibit V-10*).

There is no strategy specific neither to containing trees outside the right of way caused outages nor to making substantial outage reductions, in spite of the fact off right-of-way trees are the largest single contributor to service interruptions (*Exhibit V-9*). Rather there may be a tendency to discount outages from off right-of-way as beyond the control of the utility. This is not untypical in the utility industry as many utilities label such outages as non-preventable. However, to the customer experiencing a loss of service the relative location of the tree interrupting the service is immaterial.

Finding V-11 The articulated strategies for decreasing the impact of tree-conductor conflicts on reliability of service are inadequate.

Clear width has not been explored as a factor in improving reliability, other than accounting for the influence of slope where lines run across the slope. Outage statistics indicate tree failures outside the right-of-way account for about 35% of unplanned service interruptions (*Exhibit V-9*). No initiatives that specifically recognize and seek to address this substantial source of service interruptions were revealed.

Asset management strategies designed to improve SAIFI and SAIDI appear to focus on the circuit level. Focusing on the circuit level misses opportunities for improving reliability.

There are two factors that need to be examined in tree-related outages, those being controlling incidents and duration. While the asset management approach considers the number of customers affected by an interruption and, thereby, improving SAIDI, it does so only on the basis of the AEP Forestry standards. AEP/Kentucky Forestry has not extended the use of prescriptive treatments to address the specific areas (line segments) that have the greatest potential to negatively impact SAIDI. Application of a uniform standard fails to consider there may be portions of a circuit where a tree-related outage will take more time to locate and mitigate. If there is a probability that an outage incident on a particular portion of a circuit will have an above average negative affect on SAIDI, alternate, specific mitigation strategies are warranted.

Finding V-12 Animal protection practices are adequate.

Animal caused outages are a minor cause of unplanned service interruptions. AEP/Kentucky's approach to installing protective devices in response to emergent animal caused reliability problems is reasonable.

D. Recommendations

Recommendation V-1 Determine the annual vegetation management workload increment. (Refer to *Finding V-7*).

Trees represent a liability to utilities. Because vegetation is dynamic, there is an annual change in the tree workload inventory. To hold tree-related outages constant, the volume of annual vegetation management work completed must match the annual change in the tree workload inventory. Any portion of the annual work increment not completed enlarges by geometric progression. Failure to remove the annual workload increment results in both deteriorating reliability and increased future costs.

To prevent the escalation of costs and deteriorating reliability, the amount of annual vegetation management required (annual workload increment) must be quantified. It is a specific amount of work, representing a specific cost. Without quantification, there are only guesses.

Determining the annual workload increment necessitates a static snap shot of all current trims, removals, brush, and spray areas. In addition to this inventory, the rate of change needs to be quantified. It typically includes tree growth rates. The average rate of tree mortality over the utility forest should also be determined. As AEP/Kentucky has very high tree exposure, off right-of-way trees comprising 35% of unplanned distribution outages, tree mortality will figure prominently in managing tree-related outages.

Once this workload is determined, it would be useful to represent this information in a vegetation management layer in the Small World. This would provide a more useful representation of the information and eliminate the need to record the information on paper maps only.

Recommendation V-2 Establish pruning cycles based on measured average tree growth. (Refer to *Finding V-4*).

The field review suggests that current pruning cycles are one to two years behind. This observation is supported by the history of tree-related outages arising from trees within the right-of-way. Yet, AEP/Kentucky's experience shows it is feasible to reduce tree-related outages from within right-of-way trees to just a few percent of unplanned outages.

The present pruning cycle does not avoid tree-conductor contacts. Avoiding tree-conductor contacts should, however, be an objective of the pruning program for both safety and reliability reasons. A pruning cycle based on an inventory of trees requiring pruning and tree growth rates minimizes the number of tree-conductor contacts. Reducing outages from vegetation within the right-of-way to zero is not feasible for AEP/Kentucky because of the extremely fast growth rate of kudzu (Pueraria montana var. lobata). Typically within a maintained circuit there will be locations with exceptional growth that will require off-cycle pruning to avoid tree-conductor contacts. Such locations usually contain planted, introduced species. These locations require hotspotting and are the same ones targeted in the tree replacement program.

There are two possible ways to minimize within right-of-way tree-caused outages. The first is to establish a pruning cycle based on average tree growth. Flexibility is required to adjust the cycles up or down based on exceptional local conditions such as drought. The second approach is to substantially increase the use of hotspotting to prevent trees growing into conductors. The hotspotting approach escalates maintenance costs and is reactive. That is, hotspotting does not constitute management of the tree workload.

Recommendation V-3 Budget for vegetation management based on the annual workload increment. (Refer to *Finding V-8* and *Finding V-9*).

Successful vegetation management that manages tree-related outages can only derive from funding based on actual tree conditions. Funding based on any other premise is bound to fail the objective of providing safe, reliable, economic service. Paradoxically, because the tree workload expands exponentially, budgeting based on the actual tree workload is the path to simultaneously minimizing tree-related outages and costs.

Recommendation V-4 Use hotspotting to minimize tree-related outages until the system is on a sustainable pruning cycle. (Refer to *Finding V-5*).

Until the pruning cycle based on average tree growth is established across the entire Hazard Service Area, tree-conductor contacts will remain high. It may take a number of years to work across the whole Hazard Service Area establishing the shorter pruning cycle. In the interim, if tree-related outages are to be avoided, hotspotting must be substantially increased to prevent burners. The alternative is to maintain hotspotting at current levels, recognizing that while tree-caused outages will remain high, they will begin decreasing as more of the area is completed and maintained on the proper pruning cycle.

In areas where the new pruning cycle has been introduced, hotspotting should be used to maintain clearance at all cycle buster locations. The amount of hotspotting must be determined by the actual need in the field, unlike the current practice of ignoring hotspots because they occur in the next year's work plan. As the need for hotspotting cannot be entirely avoided, a target for the maximum amount of hotspotting should be set. However, the cap must be set based on real need. A cap of 2% to 5% is suggested as achievable with a proper pruning cycle.

Recommendation V-5 **Develop and implement practices designed to manage tree-caused outages. (Refer to *Finding V-6*, *Finding V-10*, and *Finding V-11*).**

The examination of tree-related outage history leads to a number of observations (*Exhibit V-9*).

- Within right-of-way trees account for about 20% of unplanned outages
- Within right-of-way tree-related outages have been increasing since 1997
- Reducing within right-of-way tree-related outages to less than 5% of the total is achievable
- Off right-of-way trees account for about 35% of unplanned outages

Reducing and managing within right-of-way tree-related outages could be achieved by the use of a growth-driven pruning cycle. The potential exists to reduce within right-of-way tree-related outages to below 5% of all unplanned outages.

Off right-of-way tree-related outages constitute an opportunity to substantially improve service reliability. Doing so will necessitate identification of portions of circuits where tree-related outages have above average negative effects on service reliability. Actions designed to address the location specific tree risks will need to be implemented.

An example is provided to illustrate that the potential for reducing off right-of-way tree-related outages does exist. To illustrate this potential for improving reliability, an analysis of the influence of right-of-way width follows. Assume a 34.5 kV line with the standard 50-foot right-of-way, as well as the following conditions:

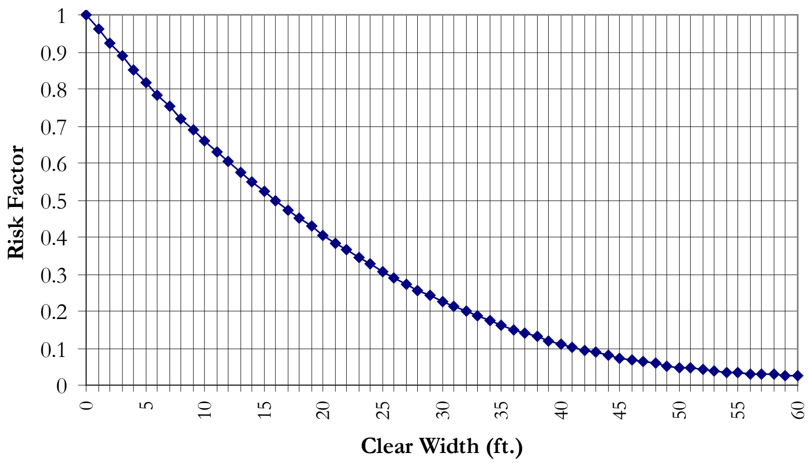
- Adjacent trees are 90 feet in height
- Average line height is 27 feet
- Tree density of adjacent trees is 220 trees/acre
- Cross arm length is 8 feet
- Tree removal costs average $50/tree

The current clear width is 21 feet (50 ft ROW/2 – 8 ft cross arm/2).

What would be the benefit and cost of increasing the right-of-way to 75 feet?

Exhibit V-11 shows the change in tree risk over a range of clear widths. There is a diminishing return in line security for the dollar invested in increasing clear width. At the current clear width of 21 feet, the tree risk factor is 0.385. Increasing the right-of-way width to 75 feet increases the clear width 33.5 feet. The risk factor associated with a 33 foot clear width is 0.186.

Exhibit V-11
Tree Risk Assessment
(Line Strike Probability for 90-foot Trees
Line Height at 27 Feet)



To facilitate assessment of the change in line security and the associated costs, information has been entered into a spreadsheet (*Exhibit V-12*). Increasing the right-of-way to 75 feet, under the assumed conditions, would reduce off right-of-way tree-related outages 52%.

Exhibit V-12
Change in Line Security
Cost Benefit Analysis

Line Segment Specific:		**Acre/Mile**	**Trees/Mile**	**Cost/Mile**	**Line Security Improvement**
Line Height	27				
Tree Height	90				
Trees/Acre	220				
Current Clear Width	21				
Current Risk Factor	0.385				
Increase Width	12.5	1.52	333		
New Risk Factor	0.186				52%
Removal Cost/Tree *	$8.00			$2,666.67	
Removal Cost/Tree **	$50.00			$16,666.67	

* Using feller bunches
** Chainsaw removals

The cost based on the assumed unit cost would be $16,667 per mile of right-of-way side. Where trees border both sides of the line, the cost will double. The cost of obtaining additional right-of-way has not been included.

While increasing the right-of-way width from 50 feet to 75 feet would produce a substantial reduction in tree-related outages, the cost is also substantial. Obviously, there would be merit in applying such an approach selectively to trouble spots that have a large influence on total customer minutes of outages.

Recommendation V-6 **Introduce contractor agreements that ensure effective costs are competitive. (Refer to *Finding V-3*).**

Consider means of assuring that contractor rates are competitive. It may require contracting with a minimum of two contractors for AEP's system.

The basis of competitive comparisons should be on the basis of effective costs, not merely on the basis of hourly labor and equipment rates offered. A measure of productivity needs to be applied as a modifier to hourly rates. AEP's RWM system can provide such a measure of productivity.