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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	Case No. 07-551-EL-AIR
Illuminating Company and The Toledo	)	Case No. 07-552-EL-ATA
Edison Company for Authority to Increase	)	Case No. 07-553-EL-AIM
Rates for Distribution Service, Modify	)	Case No. 07-554-EL-UNC
Certain Accounting Practices and for	)	
Tariff Approvals.	)	

DIRECT TESTIMONY

OF

DAVID W. CLEAVER

On Behalf of
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Columbus, Ohio 43215-3485
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January 10, 2008

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A1. My name is David Cleaver. My business address is 10 West Broad Street, Suite 1800, Columbus, Ohio, 43215-3485. I am employed by the Office of the Ohio Consumers' Counsel ("OCC" or "Consumers' Counsel") as a Senior Electrical Engineer-Energy Analyst.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A2. I have a Bachelor of Science degree in Electrical Engineering from the University of Kentucky and a Masters degree in Business Administration from the Morehead State University. I am a registered professional engineer in the state of Ohio and Kentucky and hold certifications in Ohio as a Chief Building Official and a Residential Building Official. I have over 22 years of employment in the electric utility industry beginning in 1973, first with Kentucky Utilities Company (Electrical Engineer, 1973-1977), then Kentucky Power Company (Distribution Engineer and Power Engineer, 1977-1985) and American Electric Power Service Corporation (Project Management and Controls Engineer, 1985-1995). I have spent the past twelve years working in the public sector as an electrical engineer for the City of Columbus and the State of Ohio. I have been involved with the planning, engineering, design, construction, operation and maintenance, and analysis of electric utility systems, including reliability-related matters, as an employee of investor-owned electric utilities and governmental agencies and working with developers and electricity users over a period exceeding thirty years. I have been involved in all facets of the electric utility industry beginning with the customer's meter and culminating at the generation plant. My experience includes a number of projects focused on electric utility transmission and distribution system reliability. Examples of my experience include oversight of substation and line construction crews, inspection programs, vegetation management and right-of-way clearing activities.

II. PURPOSE OF TESTIMONY

Q3. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A3. No, I have not.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. My testimony on behalf of the OCC presents the results of my evaluation of the reliability-related policies and practices that are applied to the distribution systems of the FirstEnergy electric distribution companies as contained in the Staff Reports for the Cleveland Electric Illuminating Company ("CEI"), Ohio Edison ("OE"), and Toledo Edison ("TE") (collectively, "FirstEnergy", or "the Company"). My testimony is gleaned from the portions of the Staff Reports which address the electric service reliability performance of these distribution systems for the period 2000-2006, as reflected in the electric service outage experience of the Company's distribution system. This performance has become less reliable in recent years, as reflected in the electric service reliability index data as collected by the Company and submitted to the PUCO Staff[1]. This declining performance calls into question the Company's policies and practices as they affect the reliability of the Company's electric distribution system.

Q5. ON WHAT INFORMATION IS YOUR TESTIMONY BASED?

A5. In preparing my testimony I have reviewed the Company's applications, response to OCC's discovery, responses to Staff requests, Staff Reports, work papers, and other documents discussed or mentioned in this testimony such as the 2007 Focused Assessment of the Cleveland Electric Illuminating Company conducted by UMS Group Inc. and the three Reports for the Company prepared by the Public Utilities Commission of Ohio ("PUCO" or "Commission") Staff's Service Monitoring and Enforcement Department ("Staff Reports"). In addition, I have reviewed certain documents related to Ohio electric service reliability including the May 2003 Staff Report and Stipulation filed in Columbus Southern Power and Ohio Power Company Case No. 03-2570-EL-UNC, AEP Ohio's Final Report in Case No. 06-222-EL-SLF, as well as certain proposed revisions to Ohio's Electric Service and Safety Standards Rules ("ESSS Rules"), Case No. 06-653-EL-ORD, currently before the Commission.

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[1] Ohio Adm. Code 4901:1-10-10, requires each electric distribution utility (EDU) to provide Staff an annual report of its system-wide performance against a set of reliability targets.

III. SERVICE RELIABILITY

A. Staff Report

Q6. WHAT ARE THE FINDINGS OF THE STAFF REPORTS RELATED TO THE SERVICE RELIABILITY OF THE FIRSTENERGY DISTRIBUTION SYSTEM?

A6. In its Reports, the Staff summarized the results of numerous audits performed by its Service Monitoring and Enforcement Department ("SMED") and analyzed the drivers of the Company's reliability performance. The Staff found numerous problems with FirstEnergy's record keeping systems, circuit and pole inspection programs, and vegetation management program as well as failure by OE and CEI to meet service reliability targets over a period of several years. A brief summary of the Staff's most significant findings are as follows:

- Ohio Adm. Code 4901:1-10-27 (D) (1) Scheduled Inspections: Circuits & Equipment requires yearly inspection of at least one-fifth (i.e. 20%) of the Company's distribution circuits. Changes in FirstEnergy's record keeping systems made it difficult for the Staff to confirm the Company's compliance with the 20% inspection requirement in 2004. The problem was due to FirstEnergy transitioning its records from the hard copy (spreadsheet) format to an electronic database that had not been fully deployed, leaving some inspections unaccounted for. Upon subsequent auditing, the Staff was able to confirm compliance for 2005 but the Staff Report is silent for 2006.[2]

- Ohio Adm. Code 4901:1-10-27 (E) (1) (a) through (f) Distribution Inspection, Maintenance, Etc. requires written programs, procedures and schedules for inspection, maintenance, repair, and replacement of transmission and distribution circuits and equipment.
  - Section (E) (1) (a) Poles and Towers requires a written program for the yearly inspection of one-fifth of the pole population. The Staff concluded that FirstEnergy violated this rule by using a visual external inspection only accompanied, at times, with a hammer sounding to indicate voids in the pole interior. The Staff also found that the Company was inspecting less than 5% of the pole population annually.[3]
  - Section (E) (1) (b) Conductors requires a written program for the yearly inspection of one-fifth of the distribution conductors. The Staff findings were the same as those for section (D) (1) for Circuits & Equipment in that compliance could not be verified because of changes in the Company's record keeping systems.[4]
  - Section (E) (1) (c) Pad-mounted Transformers requires a written program for the performance of required safety inspections. The Staff found problems with the transformer security inspection

[2] CEI Staff Report at 58, OE Staff Report at 56, TE Staff Report at 61.
[3] CEI Staff Report at 60, OE Staff Report at 58, TE Staff Report at 63.
[4] CEI Staff Report at 61, OE Staff Report at 59, TE Staff Report at 64.

programs which led to the re-inspection of the entire population of pad-mounted transformers for OE and CEI.[5] (TE was not affected.)

- Section (E) (1) (d & e) Line Reclosers and Capacitors requires a written program for inspecting equipment and that the Company conduct operational tests on switched capacitor banks. The Staff found that there was insufficient source documentation for OE to demonstrate that operational tests were performed on switched capacitor banks for the years 2005 and 2006. The Staff also found that OE, TE, and CEI did not perform any quality control oversight practices for inspection, maintenance, repair, and replacement of reclosers or capacitors.[6]
- Section (E) (1) (f) Right-of-way Vegetation Control requires a written program for vegetation management to verify the Company's 4-year tree trimming program. The Staff Reports' review of FirstEnergy data found that missing records and inaccurate data prevented full verification by the Staff that the Company complied with its 4-year tree trimming cycle maintenance program. For example, the Company did not provide the specific time periods (start date/end date) to show when the tree trimming process was actually conducted in each calendar year. Compounding the Staff's verification of the 4-year cycle,

[5] CEI Staff Report at 63, OE Staff Report at 61.
[6] CEI Staff Report at 65, OE Staff Report at 63, TE Staff Report at 67.

> FirstEnergy also explained that, "For the purposes of data retention, tree trimming records are maintained for one cycle or three years, whichever is the longer duration. In addition, the IVMS (Integrated Vegetation Management System) was implemented in 2003. As such, the records for 2000, 2001, and 2002 are no longer available."[7] As a result, it was difficult for the Staff to determine the specific time periods in which all applicable circuits were actually trimmed.

- Ohio Adm. Code. 4901:1-10-10 Electric Service Performance Reliability Assessment requires the Company to meet reliability indices set by the Staff and the Company on an annual basis for the System Average Interruption Frequency Index ('SAIFI") and Customer Average Interruption Duration Index ("CAIDI"). The Staff found that TE had met its SAIFI targets during all but one of the past seven years (2000-2006), OE had missed its SAIFI target during each of the past three years (2004-2006), and CEI had missed its SAIFI target during each of the past four years (2003-2006).[8] The Staff also found that TE had met its CAIDI target for five years (2002-2006), OE had met its CAIDI for all but one of seven years (2000-2006), and CEI had missed its CAIDI target for seven years (2000-2006).[9] During 2005, the Staff and the Company agreed to set interim targets for CEI to meet during years 2006-2007. CEI missed

[7] CEI Staff Report at 67, OE Staff Report at 65, TE Staff Report at 69.
[8] CEI Staff Report at 75, OE Staff Report at 72, TE Staff Report at 77.
[9] CEI Staff Report at 76, OE Staff Report at 73, TE Staff Report at 78.

its interim targets in 2006 and as a result a consultant (UMS Group Inc.) was hired to do a focused assessment of CEI's infrastructure and operational practices.

B. UMS Group Inc. Report

Q7. WHAT IS THE UMS REPORT AND HOW ARE THE RECOMMENDATIONS OF THE UMS REPORT RELATED TO THE COMPANY'S SERVICE RELIABILITY PROGRAMS?

A7. During 2005, the Staff and the Company agreed to set interim targets for CEI to meet during years 2006 and 2007 which were less stringent than those in CEI's annual ESSS Rule 10 report. The Company also agreed that if it missed any of the interim targets, it would hire a consultant to provide the Staff with an independent assessment of CEI's infrastructure and operational practices. During 2006, CEI missed all of its interim targets which triggered the hiring of the consultant. As a result, UMS Group Inc. ("UMS") was selected as the consultant to perform this assessment. That assessment is included in my testimony as Attachment DWC-1.

Q8. PLEASE DESCRIBE THE RECOMMENDATIONS OF THE UMS REPORT AS REFERENCED IN THE STAFF REPORT.

A8. The UMS Report recommends, as reported in the CEI Staff Report, eight short-term actions it believes CEI must take to meet ESSS Rule 10 reliability targets by the end of year 2009. Quoting from the CEI Staff Report:[10]

1. Enhance tree trimming program to address overhanging limbs and structurally weak trees on the feeder backbone (i.e. the main three phase feeder from the distribution substation to the first line recloser). The recommended completion date is12/31/2008.

2. Ensure lightning protection initiatives by focusing primarily on the feeder backbone, continuing to replace damaged arresters, but also consider adopting a more strategic approach by integrating Fault Analysis & Lightning Location System ("FALLS") and National Lightning Detection Network ("NLDN") data. The recommended completion date is 12/31/2008.

3. Apply a line/circuit inspection and repair prioritization scheme that focuses initially on the feeder backbone, then worst performing circuits and devices, and lastly on areas that have lesser impact on reliability. The recommended completion date is 12/31/2009.

4. Further sectionalize the 13.2kV feeder backbone (123 circuits with 500+ customers) and 4kV circuits (230 circuits with 500+ customers) on a

[10] CEI Staff Report at 77. The recommendations are scattered throughout the UMS Report. See, e.g., Attachment DWC-1 at 107 (UMS Report) ("Enhance tree-trimming program").

priority basis based on number of customers served. The recommended completion date is 5/31/2009.

5. Inspect, maintain, and test 4kV exit cable on 30 circuits with the highest number of outages on three phase cable and repair or replace as necessary. The recommended completion date is 12/31/2008.
6. Systematize the process of determining when to mobilize personnel in anticipation of a storm with expected outages between 50 and 100 per day. The recommended completion date is 6/30/2008.
7. Continue to fully implement partial restoration practices when initially servicing customer outages.
8. Continue to fully implement use of the alternate shift, based on documented evidence of reduced outage duration at critical transition time between normal shifts.

As stated in the CEI Staff Report, UMS suggests that these initiatives be concentrated on the feeder backbone within the first zone (circuit breaker to the first recloser) where service reliability for the greatest number of customers will be affected. The UMS recommendations also identify five long-term (10-years following 2009) actions. Quoting from the CEI Staff Report:[11]

1. Maintain Capital Spending at the level currently planned for 2008 ($84.7 million) for a minimum of 5 years.

[11] CEI Staff Report at 78; essentially the same as Attachment DWC-1 at 32.

2. Establish and adhere to reliability-related investments (could include capacity projects as well) at levels, percentage-wise, commensurate to those for 2007.
3. Consistent with the development of the Asset Management Strategy, develop a comprehensive plan to replace and/or refurbish the current electric distribution infrastructure, while in parallel implementing the shorter-term reliability measures (listed above).
4. Accelerate hiring to facilitate the assimilation of new personnel in advance of anticipated attrition (due to retirement).
5. Establish new service center in Geauga County's Claridon Township. The recommended completion date is 12/31/2009.

Finally, the report cites twelve (12) additional recommendations which are identified as desirable but at a lower cost benefit relationship.

Q9. WHAT WAS THE STAFF'S POSITION ON THE UMS RECOMMENDATIONS?

Q9. The Staff recommends that the Commission order FirstEnergy to immediately implement all of the consultant's short-term and long-term recommendations as listed above in accordance with their recommended completion dates. The Staff also recommends that CEI seriously consider implementing the 12 other UMS recommendations and that CEI provide the Staff with an implementation schedule for those recommendations the Company plans to implement or a detailed justification for any recommendations the Company does not plan to implement.

Q10. DO YOU HAVE ANY OBJECTIONS TO THE RECOMMENDATIONS BY UMS?

A10. I have two main objections to the recommendations by UMS. First of all, the recommendations lacked specificity. While UMS provided the Staff with an excellent roadmap to put CEI on the path to improved service reliability, I believe that the report did not drill down far enough into CEI's reliability problems in order to identify the core causes for CEI's poor performance, particularly in the area of their reliability indices. Given the amount of work that needs to be done in order to bring CEI into compliance, it is important to first prioritize the many recommendations by UMS as well as to assess what the costs will be. Further, a determination needs to be made as to what activities fall within the realm of routine maintenance that CEI should be regularly doing and that is part of the maintenance budget, and what would require additional funding.

Secondly, UMS provides no basis for recommending that CEI maintain Capital Spending at the currently proposed 2008 level ($84. 7million) or that CEI adhere to reliability-related investments commensurate to those proposed for 2007.[12] The Staff provides no justification for supporting these UMS recommended expenditures and no analysis or description of projects that they represent. Without adequate detail to analyze these UMS recommendations, there is no way to determine if the suggested expenditures represent the most cost efficient way to improve CEI's reliability.

[12] CEI Staff Report at 78.

Q11. WHAT ARE THE RECOMMENDATIONS BY UMS CONCERNING CAPITAL EXPENDITURES?

A11. UMS presents a nearly 20-year trend of the ratio of Gross Distribution Plant Additions/Depreciation for CEI and for a composite of 10 U.S electric utilities selected from similarly sized, Eastern U.S., urban/suburban systems.[13] UMS states that while CEI's capital spending pattern over time has been consistent with industry trends, such spending has been consistently lower than the average level of spending for all 18 years covered by the review. UMS also noted that CEI has exhibited one of the 1 or 2 lowest levels of investment among the 10 utilities in the composite sample in every year since 1990.[14] UMS further states that the CEI electric system may require some increased investment in the coming years to "catch up" on deferred capital replacement that has likely occurred in the past 20 years.[15]

Q12. DO YOU AGREE WITH THIS STATEMENT IN THE UMS REPORT THAT CEI MAY REQUIRE SOME INCREASED INVESTMENT IN CAPITAL SPENDING IN COMING YEARS?

A12. I do not believe that there is a simple "yes" or "no" answer to that question. While it may be logical to assume that an increase in capital spending will result in some improvement in CEI's reliability performance, there is no evidence in the UMS Report to suggest that this is the best course of action for CEI. Spending

[13] Attachment DWC-1 at 21 (UMS Report).
[14] Id. at 157.
[15] Id.

dollars on CEI's reliability programs will no doubt be a part of the formula for improving their performance. However, whether the spending activity involves increased capital expenditures or merely more focused spending of currently budgeted capital dollars remains in question. In addition, a detailed analysis of CEI's spending for reliability related Operation and Maintenance programs is also needed in order to get a complete picture of CEI's spending needs.

C. OCC Findings

Q13. PLEASE SUMMARIZE YOUR FINDINGS.

A13. While I found both the Staff Reports and the UMS Report contained many good recommendations, both lacked specificity and focus. Therefore, I have based my review on three main areas of need: (1) problems with record keeping, (2) tree trimming issues, and (3) failure to meet reliability targets. Based on my review, my findings are as follows:

1. FirstEnergy's record keeping systems and policies on a companywide basis do not meet the requirement of the present ESSS rules and also are inadequate for the purpose of verifying the Company's reliability performance, particularly in the area of its pole and circuit inspection and vegetation control programs.
2. FirstEnergy's vegetation management program based on a 4-year tree trimming cycle is an area of serious concern for the reliability of service to customers and has likely contributed to the deterioration in the Company's

reliability index performance in SAIFI and CAIDI. Also, FirstEnergy does not currently have a specific program to deal with trees outside the right-of-way as part of the vegetation management effort which it should.

3. System reliability index performance prior to 2007 (with major storm data excluded) for CEI and OE has demonstrated a trend of reduced reliability, particularly in the area of outage frequency (SAIFI) and average duration of outages (CAIDI). The decline in service reliability indices coupled with the problems noted in the Staff Reports concerning FirstEnergy's current reliability-related programs, including overhead circuit inspections, pole inspections, and vegetation management, also raises questions about the effectiveness and the quality of these programs.

Q14. WHAT ARE THE COMMISSION'S REQUIREMENTS FOR ELECTRIC DISTRIBUTION UTILITIES REGARDING PROVIDING RELIABLE SERVICE TO CUSTOMERS?

A14. The requirements regarding providing reliable service are found in Ohio Adm. Code 4901:1-10, Electric Service and Safety Standards ("ESSS" or "Rules"). These rules, as a whole, "...are intended to promote safe and reliable service to consumers and the public, and to provide minimum standards for uniform and reasonable practices."[16]

[16] Ohio Adm. Code 4901:1-10-02(A)(2) Purpose and scope.

Ohio Adm. Code 4901:1-10-02 gives the Commission the ability to waive *or go beyond* the requirements of the Rules, and states that the Rules do not relieve the EDUs from the responsibility to provide adequate service and facilities, as prescribed by the Commission. For example, the Commission could specifically address the level of service reliability provided to rural portions of the system, if such level of reliability can be shown to be inadequate.

1. Record keeping

Q15. PLEASE DISCUSS SOME OF THE SPECIFIC PROBLEMS ASSOCIATED WITH FIRSTENERGY'S RECORD KEEPING SYSTEM.

A15. Based on the findings of the Staff Reports, FirstEnergy's record keeping system has a variety of problems which require immediate correction. The Staff Reports state that missing records prevented verification by the Staff of a 4-year tree trimming cycle maintenance program on approximately 70% of its distribution circuits. The Staff's review of the FirstEnergy data for 2003 – 2006 disclosed that inaccurate data was reported. For example, while completion of a 4-year tree trimming cycle was sometimes reported, the actual completion date went beyond four years.[17] In addition, there are numerous citations in the Staff Reports concerning the difficulty in confirming FirstEnergy's compliance with the required yearly inspection of 20% of circuits and poles due to the Company transitioning its records from hard copy (spreadsheet) format to an electronic database system that had not been fully deployed, leaving some inspections

[17] CEI Staff Report at 67-68, OE Staff Report at 65-66, TE Staff Report at 69-70.

unaccounted for.[18] The OE Staff Report also cited insufficient source documentation to demonstrate that operational tests were performed on switched capacitor banks for the years 2005 and 2006.[19] Finally, both OE and CEI had problems with pad mounted transformer inspections due to inspection form issues.[20]

Q16. WHY IS ACCURATE AND COMPLET RECORD KEEPING SO IMPORTANT?

A16. Accurate and complete records are an essential component of a well run electric distribution system. If the integrity of the records is compromised, there is no way to verify how well the Company is maintaining its distribution system or to know how well the system is or is not performing. Both the accuracy of FirstEnergy's records and their retention period for records and data are in question.

Q17. WHAT IS THE DATA RETENTION PERIOD IN THE ESSS RULES?

A17. Ohio Adm. Code 4901:1-10-03 Retention of records ("ESSS Rule 03") requires that, unless otherwise specified, records sufficient to demonstrate compliance with the Rules shall be maintained for three years. Therefore, the rule requires records for three years at a minimum but since the records must also be "sufficient to demonstrate compliance", it logically follows that additional years of data may

[18] CEI Staff Report at 60-61, OE Staff Report at 58-59, TE Staff Report at 63-64.
[19] CEI Staff Report at 65, OE Staff Report at 62, TE Staff Report at 67.
[20] CEI Staff Report at 62, OE Staff Report at 60, TE Staff Report at 65.

be required if associated with a program cycle which is greater than three years. However, in areas regarding distribution system planning, maintenance and operation, retention of data for only three years is really too short a period to be sufficient for reliability purposes. There are a number of reasons for this. First, three years is too short because changes in the facilities installed on a distribution circuit and/or maintenance performed on a distribution circuit typically take some time to implement and even more time before they are reflected in the reliability performance of the circuit to which they apply. For example, in order to determine if a distribution circuit is having reliability performance problems, typically at least one year of reliability performance data is needed. Next, once a distribution circuit is determined to be a candidate for reliability improvement, the repair and/or replacement of poles, crossarms, and/or conductors, the application of directed tree trimming, and the implementation of other improvements will take additional time to be completed. These types of projects typically can take 1-2 years to be fully implemented. Finally, once implemented, it will take some time for the reliability performance of the circuit in question to reflect these improvements, typically at least one year of operation after the completion of improvements.

Without more than three years of information, the ability is lost to correlate the level of maintenance and design that lead to poor reliability performance, and, therefore, to contrast it with what was done to improve reliability performance.

Another reason that three years is too short a data retention period is that design or policy changes take time to actually be applied to enough of the system to have an impact on system performance. For example, FirstEnergy might decide to change its distribution circuit tree-trimming policy from once every 4 to 6 years to once every 3 to 5 years. If such a policy change is decided upon, it will typically take time for this policy change to actually be reflected in the trimming of all distribution circuits. If a distribution circuit that would have been trimmed every six years under the old policy is trimmed the year the policy change goes into effect, then it could take three to five years for the new policy to actually be reflected. Then, another year would be needed after that, at a minimum, to get one full year of reliability performance data reflecting full implementation of the policy change.

A third reason why more than three years of data is needed is that some kinds of distribution system maintenance and/or inspections can be reduced or discontinued with little or no immediate impact on system reliability, but, that, over time, such reductions or discontinuances can have significant reliability impacts on service to customers. For example, if distribution tree-trimming were to be sharply curtailed, it could be more than a year before such curtailments were reflected in significant numbers of distribution circuits and the vegetation of these circuits had grown enough to affect reliability. Then, another year would be needed after that, at a minimum, to get one full year of reliability performance data reflecting full implementation of the reduction/discontinuance.

Q18. WHAT MINIMUM DATA RETENTION PERIOD DO YOU RECOMMEND FOR FIRSTENERGY?

A18. It is my opinion that the intent of the ESSS rules concerning record retention is to require enough records to verify compliance with all maintenance programs. Therefore, a 4-year tree trimming program requires records for all four years of the tree trimming cycle and records for all five years are needed for an annual one-fifth pole inspection program. Considering the problems encountered with FirstEnergy's record keeping systems and CEI's poor performance in meeting reliability targets, a minimum data retention period of five years is needed in order to have a reasonable chance of correlating the level of distribution system electric service reliability that results from specific planning, maintenance, or operating policies.

2. Vegetation management

Q19. PLEASE ADDRESS FIRSTENERGY'S PROGRAM FOR DISTRIBUTION VEGETATION MANAGEMENT.

A19. Vegetation management is one of the more problematic areas of the Company's distribution maintenance programs. The Company's distribution system vegetation management program filed with the Commission reflected total circuit trimming on a four-year cycle. As noted previously in my testimony, missing records and inaccurate data made it difficult, if not impossible, for the Staff to confirm whether FirstEnergy is adhering to their tree trimming program. As stated in the Staff Reports, the Company provided data covered only 29.68% of the circuits, leaving 70.32% of the circuits without records and the Staff was unable to verify actual start date/end date data or compliance with the 4-year cycle requirement for the same period. As a result of FirstEnergy's inability to prove compliance with accurate data, the Company has not complied with the 4-year cycle requirement. Additionally, this conclusion is further supported by the fact that the Company's performance as reflected in its reliability indices (SAIFI and CAIDI) for CEI and OE has steadily declined over the past several years.

Q20. WHY ARE TREE TRIMMING PROGRAMS AN AREA FOR REGULATORY FOCUS REGARDING THE QUALITY OF SERVICE PROVIDED BY THE ELECTRIC UTILITIES?

A20. It has been my experience after working for many years in the industry that tree trimming programs are a common area of concern regarding most electric utilities. There are two main reasons for this industry phenomenon. First, most tree trimming programs are performed by contract crews. The pay for workers on these crews is typically very low and this results in high turnover, making it difficult to have the continuity of experience and a consistently high quality work product. In addition, it is much easier for utility management to cut back on contract work if budget cuts are required or desired than it is to eliminate work for its own employees. In other words, when funds are scarce or utilities are seeking to enhance profits by reducing expenses, it has been my experience that tree trimming contractors are the first to go. Second, an electric utility will not experience any immediate consequences when delaying or completely eliminating tree trimming activity. Rather it will take at least one or two growing seasons, possibly even more for slow growing vegetation, before the lack of tree trimming is reflected in the reliability indices, such as SAIFI and CAIDI. It is my opinion therefore that there is frequently a direct link between a reduced and/or inefficient vegetation management program and an electric utility's declining performance indices for quality of service to customers.

Q21. WHAT IS THE RELATIONSHIP BETWEEN VEGETATION MANAGEMENT AND BOTH PERMANENT AND MOMENTARY OUTAGES IN ELECTRIC SERVICE FOR CUSTOMERS?

A21. Vegetation management is a significant factor as a cause of both permanent service interruptions, as measured by indices such as SAIFI and CAIDI, as well as momentary service interruptions (i.e. interruptions which last five minutes or less). If vegetation management is neglected, the distribution system may be allowed to atrophy to a level where the number of momentary outages will gradually increase. Even though momentary interruptions are not reported by the Company, these interruptions are important for two reasons. First, they can cause loss of data in computers that many customers use and can result in the need to reset many types of modern appliances and electronics in consumer households. Second, they are a sign that the distribution system is under stress and in need of maintenance.

Momentary outages occur when circuit breakers and/or reclosers on overhead distribution circuits operate, i.e., open, when a fault is detected, and then close after a few seconds, to see if the fault has cleared. If the fault is gone, the breaker or recloser stays closed, and customers downstream from that device have experienced a momentary outage. If the fault is still there, the device opens again and typically locks out in the open position until the circuit can be checked for faults. Falling tree branches and tree limbs swaying in the breeze can cause faults that disappear after a second or two. When a distribution circuit experiences high numbers of momentary outages, trees are one of the most likely causes. Of course, since the Company does not report numbers of momentary interruptions, a customer would most likely have to complain before the Company became aware of the problem. However, since the Company's indices for SAIFI and CAIDI have increased, it would follow that the frequency of momentary outages has also increased proportionately.

Q22. WHAT ARE SOME OF THE VEGETATION MANAGEMENT PROGRAMS THAT ARE TYPICAL AMONG ELECTRIC UTILITIES?

A22. The use of "performance-based" direction of at least some vegetation management activities is on the increase among electric utilities. It may take the form of something as simple as annual listings of a utility's worst performing distribution circuits, with these circuits targeted for remedial action that frequently includes tree trimming. However, many utilities still have an overall trimming cycle based on a comprehensive trimming, or other application of vegetation management techniques, every so many years. There is considerable variability in the lengths of these cycles. My experience in other states indicates that some utilities are switching to a three-year vegetation management cycle for distribution facilities, while others use a four-year, or longer, cycle.

Some utilities use mid-cycle hot-spot trimming which concentrates tree trimming efforts on circuits experiencing reliability problems. However, the use of a vegetation management policy that rations tree trimming and other vegetation management activities only to those distribution circuits that exhibit especially poor electric service reliability due to tree-related faults probably comes at a cost to overall system reliability for customers. Minimizing tree trimming in this way leaves a lot of vegetation in close proximity to circuits, which also tends to increase the tree-related problems that occur during storms. The Company's recent reliability index performance certainly suggests that increased storm response and service restoration capabilities may be needed as part of its performance-based program of vegetation management.

Q23. PLEASE DISCUSS RELIABILITY PROBLEMS CAUSED BY TREES OUTSIDE THE DISTRIBUTION RIGHT-OF-WAY.

A23. The Company's vegetation management proposal does not appear to address the service interruptions caused by trees located outside the distribution right-of-way. Such trees represent a special problem, as a utility's right to trim trees located outside the right-of-way is usually limited and frequently requires permission from property owners.[21] Additionally, outages caused by such trees are one of the five leading causes of outages on the Company's system in recent years, as noted later in my testimony concerning system reliability performance indices.

Programs to try to deal with the most threatening trees located outside the right-of-way are an increasingly common part of vegetation management plans. Such programs typically take note of trees near the right-of-way whose limbs and trunk could pose a danger to the distribution circuit if they were broken and fell to the ground. If these pose an imminent threat to the line, such as if they are dead, or if they overhang the line, they are typically removed for safety considerations. Otherwise, permission from property owners to remove the tree is sometimes required and is actively pursued. The Company's vegetation management plan should include provisions to address these problem trees.

Q24. WHAT ARE OCC'S RECOMMENDATIONS CONCERNING FIRSTENERGY'S VEGETATION MANAGEMENT PROGRAM?

A24. OCC recommends that FirstEnergy implement a performance-based vegetation management program which also addresses problems caused by trees outside the distribution right-of-way.

[21] The trimming of limbs that extend into the right-of-way are typically not restricted in this way.

3. System reliability indices

Q25. HOW IS SERVICE RELIABILITY FOR AN ELECTRIC DISTRIBUTION SYSTEM TYPICALLY MEASURED?

A25. Although there are a number of ways to measure electric distribution service reliability performance, the reliability indices SAIFI, CAIDI, and System Average Interruption Duration Index ("SAIDI") are among the most widely used.

SAIFI refers to the System Average Interruption Frequency Index, and is calculated by dividing the total number of sustained customer service interruptions by the total number of customers served. For a calendar year period, SAIFI represents the average number of sustained electric service outages per customer served during that period. SAIFI may be calculated for time periods other than a calendar year as well.

CAIDI refers to the Customer Average Interruption Duration Index, and is calculated by dividing the sum of the individual customers' minutes of sustained electric service interruption by the total number of individual customer interruptions. For a calendar year period, CAIDI represents the average number of minutes of electric service interruption for each customer service interruption, or, put another way, the average outage duration. CAIDI may be calculated for time periods other than a calendar year as well, and is sometimes calculated in hours, rather than in minutes.

SAIDI refers to the System Average Interruption Duration Index, and is calculated by dividing the sum of the individual customers' minutes of sustained electric service interruption by the total number of customers served. SAIDI can also be calculated by multiplying SAIFI times CAIDI. For a calendar year period, SAIDI represents the average number of minutes of electric service interruption for each customer served. SAIDI may be calculated for time periods other than a calendar year as well, and is sometimes calculated in hours, rather than in minutes.

For all of these reliability performance indices, a lower value reflects more reliable performance, while a higher value reflects less reliable performance. For example, for CAIDI, which measures the average duration of outages, a value of 100 would mean 100 minutes of outage time, while a value of 140 would mean 140 minutes of outage time – a longer period of time without electricity.

Q26. WHY ARE THE COMPANY'S RELIABILITY INDICES IMPORTANT?

A26. The Company's reliability indices are like the pulse beat of a healthy electric distribution system. Much like the vital signs of a living organism, these indices are an extremely important source of information for determining if the distribution system is performing adequately, if the system is being operated and maintained properly, and if the system is experiencing problems which require remedial action.

Q27. WHAT HAS THE COMPANY'S RELIABILITY PERFORMANCE BEEN LIKE IN RECENT YEARS?

A27. As stated previously in my testimony, the Staff Reports for OE and CEI indicate that OE has missed its SAIFI target during each of the past three years (2004-2006) and that CEI has missed its SAIFI target during each of the past four years (2003-2006) by generating an average interruption frequency that exceeds its target level. In addition, CEI has also missed its CAIDI target during each of the past seven years (2000-2006) by generating an average restoration time that exceeds its target level. The trend toward declining reliability for CEI and its customers is unmistakable and the obvious conclusion is that immediate and drastic action is needed on behalf of the public to reverse this downward trend.

Q28. WHAT HAVE BEEN THE LEADING CAUSES OF OUTAGES ON THE COMPANY'S SYSTEM?

A28. The Company's leading outage causes in recent years, as noted in the Staff Reports, are equipment failure, line failures, distribution substation causes (breakers and transformers), trees in the right-of-way, trees outside the right-of-way, and animals.

Q29. WHAT IS OCC'S RECOMMENDATION CONCERNING THE COMPANY'S RECENT PERFORMANCE IN NOT MEETING ITS SERVICE RELIABILITY TARGETS?

A29. The OCC recommends that the declining performance of FirstEnergy, particularly that of CEI, in meeting its service reliability targets be reflected in an adjustment to lower the Company's allowed Rate of Return ("ROR") in this distribution rate case. Additional discussion of the recommended ROR is in the testimony of OCC witness Aster Adams.

IV. OCC RECOMMENDATIONS

Q30. **IN SUMMARY, WHAT ARE OCC'S RECOMMENDATIONS RELATED TO PROTECTING AND IMPROVING SERVICE RELIABILITY FOR CUSTOMERS?**

A30.

1. Due to the problems associated with FirstEnergy's record keeping systems, OCC recommends that the Commission require FirstEnergy to use a minimum data retention period of five years.
2. Due to the declining performance of FirstEnergy, and particularly that of CEI, in meeting its service reliability targets and due to problems documented in the Staff Reports concerning the Company's vegetation management program, OCC recommends that FirstEnergy implement a performance-based vegetation management program which also addresses problems caused by trees outside the distribution right-of-way.

3. Due to the declining performance of FirstEnergy, and particularly that of CEI, in meeting reliability targets for service to its customers, OCC recommends that the Commission reflect the Company's under-performance in the allowed Rate of Return in this distribution rate case. The downward adjustment in the Rate of Return is addressed in the direct testimony of OCC witness Aster Adams.

4. Due to the depth and breadth of the problems associated with FirstEnergy's service reliability programs, OCC recommends that the Commission utilize its authority, pursuant to Ohio Revised Code 4905.26, to investigate the sufficiency and adequacy of FirstEnergy's service quality and to hold a hearing regarding FirstEnergy's service quality.

Q31. DOES THIS CONCLUDE YOUR TESTIMONY?

A31. Yes, however, I reserve the right to supplement my testimony to incorporate new information that may subsequently become available through discovery or otherwise. Additionally, I reserve the right to supplement my testimony in the event that the PUCO Staff fails to support or otherwise change the recommendations it has made in the Staff Reports filed with this Commission on December 4, 2007.

Attachment DWC-1

Final Report

2007 Focused Assessment of the Cleveland Electric Illuminating Company

Conducted by

UMS Group Inc.
5 Sylvan Way, Suite 120
Parsippany, NJ 07054

October 2007

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1.0 Executive Summary

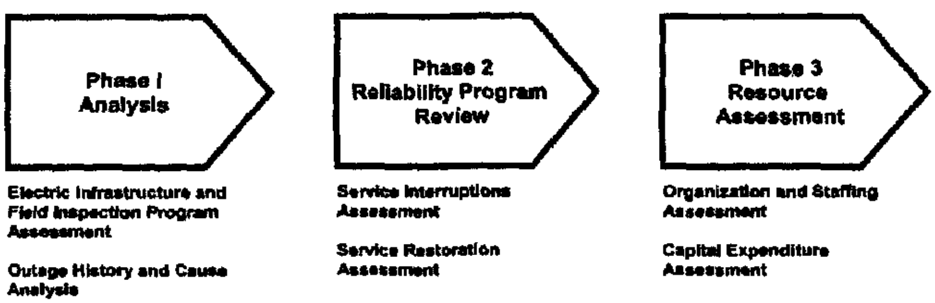
1.1 Introduction

In the Summer and Fall of 2007 UMS Group conducted a focused assessment of the practices, policies, and procedures of The Illuminating Company (hereinafter referred to as "CEI" or "the Company") relating to the Company's efforts to improve electrical system reliability in its distribution network during the 2002-2006 period. Our overarching objective was to identify specific reliability improvement opportunities to enable the Company to achieve its existing reliability targets by 2009 and to sustain this level of reliability performance over the following 10-year period.

In so doing, we examined the effectiveness of the Company's recently implemented procedures, initiatives, and technologies to improve overall reliability performance. Our approach to this work involved a three-phased diagnostic process to both identify and estimate the impact of potential improvements to the Company's current reliability programs.

Figure 1-1 below characterizes the nature of our three-phased assessment approach.

Figure 1-1
UMS Group's 3-Phased Diagnostic Process



Phase 1: Infrastructure and Outage History and Cause Analyses

During this initial phase, UMS Group conducted a selected sampling across CEI's 2 substation areas and 9 distribution line districts to verify the accuracy of CEI's system condition records, visually assess the physical condition of a sample of the system assets, and determine the effectiveness of and adherence to the Company's established Field Inspection policies and practices. The details of this analysis are presented in Section 2.0 of this report.

Based on the findings of this inspection effort, we then analyzed a 5-year history (2002-2006) of outage events at both the company and district level to determine the major drivers of system reliability performance and to identify targeted opportunities for cost-effective reliability improvement. From this analysis we developed insights and conclusions to (1) validate many of the ongoing practices and (2) develop recommendations to not only reach the 2009 reliability performance targets but to sustain that level of performance for 10 years. Section 3.0 of this report highlights the detailed results of the outage analysis.

Phase 2: Reliability Program Review

Building on the findings of Phase 1 of our analysis, we conducted over 29 technical interviews to assess: (1) CEI programs and approaches to eliminate and/or remediate customer interruptions (measured by SAIFI); and (2) the processes and practices employed in reducing customer minutes of interruptions (measured by CAIDI). A number of recommendations were developed, providing a roadmap for sustainable improvement in SAIFI and CAIDI. This effort also included the analysis of over 69 major data requests presented to the Company. Section 4.0 of this report highlights the Reliability Framework we used to structure our analysis. Section 5.0 of this report describes the Company's performance and improvement opportunities related to service interruptions; Section 6.0 of this report highlights the Company's performance and improvement opportunities related to service restoration.

Phase 3: Resource Assessment

The third phase of this assessment acknowledges that the recommendations developed during the Reliability Program Review will require resources in the form of skilled staff, effective organization, and adequate funding to be properly implemented. Section 7.0 of this report provides a detailed review of the Company's organization and staffing levels as they relate to system reliability and Section 8.0 explains our analysis of the Company's capital expenditure process.

During this phase, UMS Group developed a rationale and strategy to better identify the proper funding and staffing levels necessary to support our recommendations and achieve the targets specified in the 2005 ESSS Rule 10 Action Plan.

As part of this three-phased effort, UMS Group also independently reviewed CEI's performance against the 2005 ESSS Rule 10 Action Plan for compliance and to assess its impact on the Company's ability to realize the reliability targets as specified by the Public Utility Commission of Ohio (hereinafter referred to as "PUCO", with its supporting staff referred to as "the Staff"). The findings of this analysis are contained throughout this report and they are also expressly summarized in Section 9.0 of this report

The following sections of this Executive Summary present a synopsis of our major observations, recommendations, and conclusions related to this assessment. The detailed results of our assessment are presented in the corresponding report sections in the remainder of this report. The more significant reliability-related improvement opportunities identified in this report are also highlighted and evaluated at the end of this Executive Summary section. In this context, we present (where applicable) an estimated cost and anticipated reliability impact of these recommendations to overall system reliability performance.

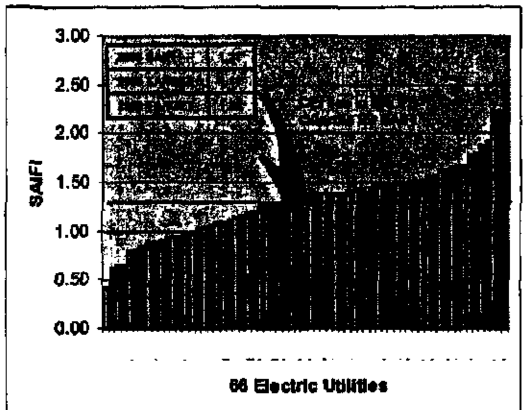
1.2 General Overview

As a result of this assessment, UMS Group has concluded that CEI is committed to improving overall electric system reliability. The Company's recent efforts have not only been designed and implemented to meet the specific provisions of the 2005 ESSS Rule 10 Action Plan (a detailed analysis of the Company's compliance is presented in Section 9.0). More importantly, we believe that the evidence outlined in this report supports the conclusion that the Company and its management team have been making measurable improvements related to system reliability in many aspects of its operation of, maintenance of, and investment in the CEI distribution system.

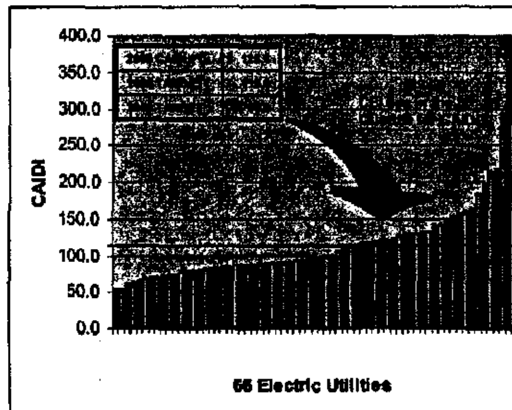
Although the results of this assessment are not uniformly positive in terms of performance or outcome, we believe that the evidence presented in this report shows that the Company has made and is continuing to make the necessary improvements in its procedures, processes, practices, spending levels and patterns, and investment planning that are necessary to improve system reliability and to ultimately meet the agreed upon reliability targets.

This assessment defines the actions (and their rationale) necessary for the Company to meet the targeted levels of reliability performance (specifically, SAIFI of 1.0 and CAIDI of 95.0) by 2009. From an industry-wide perspective, the challenge confronting the Company is that of striving to meet "top-quartile" performance in SAIFI and "second quartile" performance in CAIDI. Figure 1-2 below characterizes the Company's targets in the context of general industry patterns.

Figure 1-2
Industry Context for CEI's SAIFI and CAIDI Targets



Quartile	1st	2nd	3rd	4th
SAIFI	<1.05	1.06-1.38	1.39-1.53	>1.53



Quartile	1st	2nd	3rd	4th
CAIDI	<83.1	83.2-98.7	98.8-131.1	>131.1

The Company is committed to these existing targets and it understands and acknowledges this context and the scope of its challenge. The solution requires a programmatic, longer term strategy than can be realized between now and 2009. FirstEnergy's recently inaugurated Asset Management initiative has the potential to provide this solution by establishing a focus on maintaining and operating critical equipment (and associated components/sub-components) and ensuring tighter correlation between capital spending and system reliability through a well-planned and integrated prioritization process.

Significant financial and human resource commitments have already been made by FirstEnergy to this initiative. A detailed description of this initiative is presented Section 8.0 of this report and we note that it offers the Company its greatest opportunity and yet also its largest risk in terms of meeting the long range objective of sustained system reliability improvement over a 10-year period.

We believe that the Company's plans as they are currently conceived contain many of the key elements necessary to deliver the desired and expected reliability improvement. Our recommendations as outlined in this report in many cases accentuate or "fine-tune" existing practices or plans rather than identify previously unexposed opportunities. However, given the current material condition of the system (outlined in Section 2.0 of this report), we believe that the Company's ability to reach (or miss) these goals by 2009 will likely be more of a function of favorable (or unexpected) conditions (e.g. weather patterns, location of specific outages) than confirmation that the plans have reached their full potential.

Moreover, as is often the case when embarking on reliability improvement programs, there may even be a temporary reduction in *measured* reliability performance as the customer interruptions are reduced just enough to include storms that would have otherwise (under a less stable system) been excluded. Of course, over time the effect of a well-planned and executed plan will produce the sustainable results called for in the 2005 ESSS Rule 10 Action Plan.

With respect to the targets themselves, as Figure 1-2 illustrates, they are appropriately aggressive in that top-quartile SAIFI performance and second quartile CAIDI performance are by no means unreasonable goals to establish, particularly over the long run. Our belief is that in the case of the CEI they would represent outstanding performance (for the reasons specified above), particularly when compared with the targets established for the other Ohio utilities and similar systems (in terms of overhead/underground mix, age, condition, etc.)

During the period this report was being prepared, we also note that we became aware of PUCO Staff analysis of potential pending rule changes to what constitutes an excludable event. The storm exclusion threshold may be increased from 6 percent of total customers to 10 percent of total customers, all outages less than 5 minutes (currently at one minute) may be excluded, and planned outages (previously excluded) may be included. Using 2006 as a baseline (strictly for comparative purposes), the net impact of these potential changes would have increased the Company's SAIFI performance by 0.1 and CAIDI performance by 45 minutes.

The major contributor to these differences is adjusting the storm exclusion threshold to 10 percent of total customers (the approximate range for the 2.5 beta standard). Obviously, a more comprehensive analysis is called for (perhaps a 3-year average impact assessment); but, a dialogue around normalizing targets (or perhaps applying the new targets to smaller geographic areas) seems appropriate.

The discussion above regarding existing performance targets and potential measurement changes (that would potentially alter the nominal target for comparability) notwithstanding, the remainder of this report will focus on the targets as specified in the 2005 ESSS Rule 10 Action Plan and the ability of the Company to sustain that performance for 10 years.

Overall, the Company's reliability performance as presented in Figure 1-3 has improved in terms of service restoration (stepped improvement in CAIDI between the 2002/2003 time frame and the past 3 years), but with respect to service interruptions has not returned to 2002 level. Moreover, the performance from year to year has oscillated.

Figure 1-3
CEI 5-Year Reliability Performance

Measure	Units	2002	2003	2004	2005	2006
SAIDI	Minutes	147.21	205.10	149.69	193.25	150.44
SAIFI	Interrupts	0.95	1.22	1.14	1.69	1.17
CAIDI	Minutes	154.42	167.67	131.56	114.20	128.29

Special Note – The data shown in Figure 1-2 above originates from an updated database and does not precisely match the information reported to PUCO. The variance between this presentation and prior report is approximately 1 minute for CAIDI/SAIDI and less than 0.1 for SAIFI.

This lack of stability of performance suggested a need for thorough review of the Company's elimination and mitigation strategies for customer interruptions and a review and fine-tuning of the Company's practices currently instituted to reduce the duration of these interruptions

As we reviewed the Company's practices and processes around these performance measures and compared them with those of top quartile performers, we identified few actions that were not already in some form of implementation within the Company. However, as the following report will show, we believe that by disaggregating the outage data we were able to identify some key leverage points to assist the Company in maximizing the impact of these programs in the short term and identified longer term initiatives to fulfill the 10-year commitment of sustained reliable performance.

1.3 Reliability Analysis (Focused on 2009 Performance Targets)

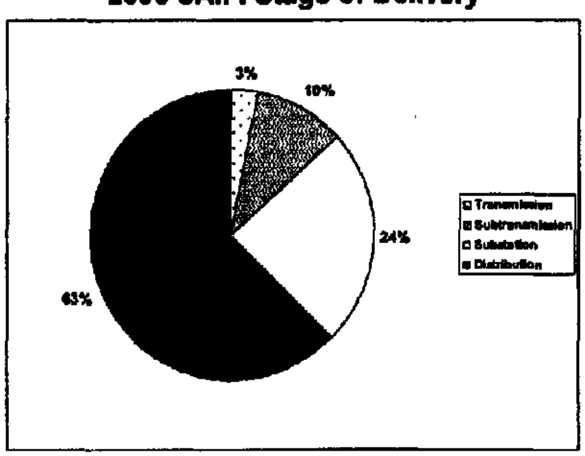
In establishing focus and direction to this analysis, we narrowed our view to "Non-Storm" events As a point of clarification, "Non-Storm" is synonymous with "Non-Major-Storm"; that is, while 'non-storm' excludes major storms that affect more than six percent of the Company's customers for a sustained 12-hour period, 'non-storm' includes the impact of minor storms, and is, in fact, driven at the margin by the frequency and severity of such minor storms and by the system's ability to minimize the interruptions and the outage durations experienced by customers in such minor storms. With that established we then disaggregated our analysis to better target areas that would provide the best leverage in improving reliability, initially focused on reducing service interruptions.

1.3.1 Reduce Customer Interruptions

Stage of Delivery

We initially looked at contributors to SAIFI (Figure 1-4) by Stage of Delivery (Transmission, Subtransmission, Substation and Distribution), where Distribution refers to the feeders. Obviously, the greatest opportunity for improvement is in the feeders (*over 60 percent of the customer interruptions are attributed to feeders*). That is not to say that improvement is not warranted in the areas of Subtransmission and Substations. But, the number of customer interruptions in these stages of delivery has been reduced, and the measures already taken should be sufficient to provide continued improvement.

Figure 1-4
2006 SAIFI Stage of Delivery



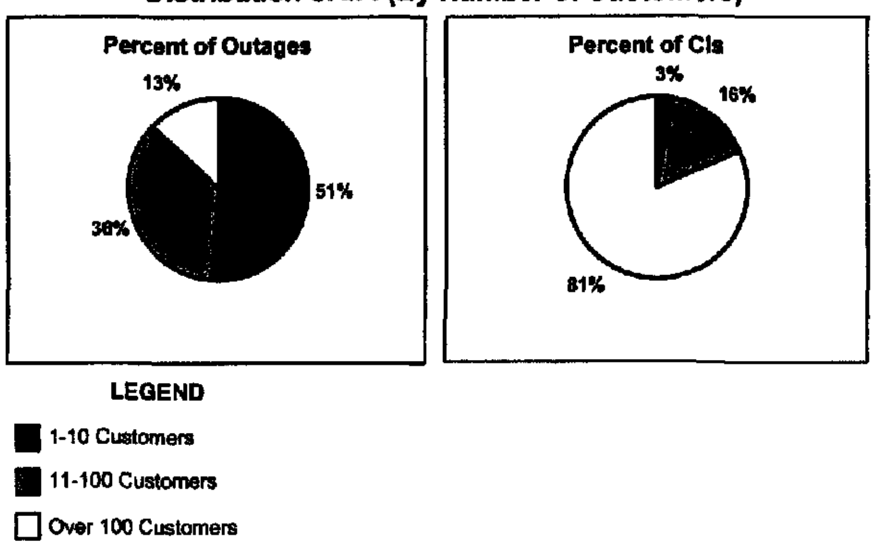
In reviewing the implications of the Stage of Delivery analysis (Figure 1-4), the following key points are summarized:

- The primary focus on this assessment should be on Distribution (it contributes 0.76 to SAIFI or 63 percent of the customer interruptions)
- Substation SAIFI, contributing 0.29 to SAIFI or 24 percent of the customer interruptions, requires parallel focus. However, the Feeder Breaker and Relay replacements and Animal Protection already being implemented across CEI should be sufficient to maintain steady improvement.
- Subtransmission SAIFI (contributing 0.12 to SAIFI or 10 percent of the customer interruptions) improved significantly between 2005 and 2006 (a 72.4 percent reduction in customer interruptions due to improved operability of the switches on the subtransmission system).
- Transmission SAIFI is negligible (not covered in this assessment).

Distribution SAIFI by Number of Customers Served

Within distribution (feeders), we then reviewed the distribution outages across the number of customers served. Figure 1-5 below illustrates that a relatively small percentage of outages (13 percent) had an appreciative effect on the numbers that drive SAIFI (customer interruptions). Therefore, any strategies and tactics aimed at reducing customer interruptions need to reflect the fact that 87 percent of the distribution outages accounted for only 19 percent of the customer interruptions (this is also indicative of effective fusing previously implemented by the Company).

Figure 1-5
Distribution SAIFI (By Number of Customers)



Distribution SAIFI by Cause Code

We then segmented the analyses from a number of different perspectives (e.g. voltage class, feeder breaker lockouts, geography), but in terms of identifying additional leverage points for development of strategies and actions, the SAIFI by Cause Code view provided the best insights. Over a five year period, 3 cause categories (Line Failure including lightning and wind-caused outages, Equipment Failure, and Trees/Non-Preventable) offer the Company its best opportunities (i.e. 89 percent of feeder-related SAIFI fell into these categories).

Figure 1-6 below presents this causal analysis by year.

Figure 1-6
Key Causes of Distribution SAIFI

Failure Cause	2002	2003	2004	2005	2006
Line Failure	0,12	0.22	0.21	0.25	0.26
Equipment Failure	0.10	0.10	0.11	0.14	0.24
Trees/Non-Preventable	0.09	0.09	0.11	0.11	0.13
TOTAL	0.31	0.31	0.43	0.50	0.63
PCNT D-SAIFI	83%	87%	87%	84%	89%

Key Strategies and Actions

Integrating the information derived from these four views, a two-tiered strategy was developed to ensure the Company maximizes its overall system reliability performance (as measured by SAIFI and CAIDI), yet maintains its focus on customer satisfaction. This strategy was composed of the following elements:

- **Protect the Backbone:** The cornerstone of this strategy is a focus on the feeder backbone. The backbone is the normally three-phase part of the circuit that runs unfused from the substation to the *normally open* ties to other circuits or to the physical end of the circuit (i.e. at a geographical or territory boundary, etc.). The backbone may include reclosers, but not fused taps. The associated actions are designed to either eliminate or mitigate customer interruptions:

  Vegetation Management (Eliminate Customer Interruptions)

  CEI's four-year tree trimming cycle under the FirstEnergy Vegetation Management Specification has been effective in reducing customer interruptions attributable to the category "tree-preventable", as evidenced by a reduction of contribution to SAIFI of .01 in 2003 to .001 in 2006 (ninety-nine percent of the tree-caused outages were characterized as non-preventable). UMS Group recommends that CEI extend the program to target "Priority" trees (in addition to the current "Danger" Tree program), i.e. – those that are most likely to cause outages to the backbone caused by broken limb/fallen tree situations

  This program would not be focused on merely avoiding grow-in contact-caused outages (although that effort must continue) but also on avoiding the most customer-impacting cases of broken limb and fallen tree by doing more to remove overhanging limbs and structurally weak trees. This approach cannot normally be cost-effectively applied to the entire system. The kind of clearances required would often be deemed excessive on the taps that typically serve two-lane suburban streets. However, feeder backbones typically are adjacent to major thoroughfares and commercial areas where enhanced removal is often more acceptable, particularly on the second or third time as the tree begins to take on the appearance of one that has 'grown away from the lines'.

  Lightning Protection (Eliminate Customer Interruptions)

  While deploying lightning arresters is the standard remedy (and usually a good one), there are other considerations that should be factored. These include: grounding, type of construction, and structures that support both transmission and distribution lines. CEI should also more effectively integrate the insights available via the National Lightning Detection Network and the software program FALLS (Fault Analysis and Lightning Location System) to identify opportunities to more effectively protect the feeder backbone from lightning. Note that successful implementation requires that a lightning analysis be conducted before any protection solution is implemented.

Repair Pole and Pole-Top Fault Causing Equipment Problems (Eliminate Customer Interruptions)

UMS Group recommends that the current ESSS Inspection Program be integrated with this notion that a more select focus on the feeder backbone will provide the highest value in terms of inspection and follow-up on any noted deficiencies/exceptions. That is not to say that the inspections outside of the feeder backbone will be eliminated, but it does speak to frequency of inspections, and a more reliability-centered process of prioritization with varying follow-up time frame requirements.

Animal Mitigation (Eliminate Customer Interruptions)

CEI has integrated its Animal Guarding Program with its Line Inspection Programs and Substations utilizing planned and forced outages to apply the material already in stock. We have no additional recommendations to provide the Company in this area.

Feeder Sectionalizing (Mitigate Customer Interruptions)

In reviewing the over 1,000 4kV and 13.2kV circuits within the CEI system, 825 circuits do not have reclosers installed. Over 350 of these circuits serve more than 500 customers (considered by CEI as the optimum cut-off point for considering the installation of reclosers). Figure 1-7 provides a tabulation of these circuits by number of customers and voltage class:

Figure 1-7
CEI Circuits without Reclosers

Number of Customers	**4kV Circuits**	**13.2kV Circuits**	**TOTAL**
>2,000	0	24	24
1000-1999	37	64	101
750-999	80	16	96
500-749	113	19	132
TOTAL	**230**	**123**	**353**

Notwithstanding that many of these circuits may have experienced few, if any, backbone outages and some could be underground, this figure does suggest an opportunity to further sectionalize the feeder backbone and reduce the number of customer interruptions.

Another item to consider is the replacement of existing three-phase reclosers with single-phase reclosers (as well as using banks of single-phase reclosers for new recloser installations). Like many of our recommendations, this option should be considered on a circuit-by-circuit basis. Clearly, the advantage of reducing the number of interruptions by two-thirds is attractive. However, depending on the needs of the customer on that circuit, the impact to a major commercial or industrial customer that requires all three phases needs to be weighed against this benefit to other customers on the circuit.

Relaying/Over-Current Protection (Mitigate Customer Interruptions)

The primary operating issue with respect to relaying involves the decision to use the instant trip and timed re-close feature on reclosers. Our general recommendation with respect to this issue is that it is a decision that should be made on a circuit by circuit basis (i.e. not as a blanket policy across the entire system), considering the nature of the circuit and its customers, the history of success with instant trip and timed re-close on that circuit, and the damage that might be done to equipment if the instant trip is not set.

4kV Considerations (Eliminate Customer Interruptions)

Generally speaking, because of the relatively short runs of circuits associated with the 4kV system, sectionalizing provides little (if any) potential to improve reliability. However, since the 4kV feeders are more numerous, their exits from the substation often need to be underground, perhaps going a quarter-mile or more underground before reaching an overhead riser. As a result, cable failures on the exit cable, which would necessarily cause a lockout of the entire feeder, can be a common problem and one that will get worse as the very old cable in the similarly old conduits begins to reach the end of its useful life. We recommend that CEI continue its program of inspecting, maintaining, and even testing such cable in its attempt to prevent outages of this type.

- **Respond to Non-Backbone Multiple Customer Interruptions:** Sole focus on protecting the feeder backbone will inevitably lead to problems with respect to customer satisfaction. Whether a customer happens to be served by the backbone or off a tap brings no solace when confronted with an interruption in service. To address this, we suggest establishing a threshold criteria in terms of repeat interruptions (a pre-specified number of interruptions within a specified time frame) to initiate a proactive response. Obviously, all customers will get their service restored. The issue is when and to what extent a more comprehensive solution will be put in place that will prevent future outages. The following programs are natural candidates for this type of approach:

Worst Performing Devices

While it may not be cost-effective to try to avoid every outage on every device (especially when there is no obvious pattern that would lead one to target a class of devices as being most likely to fail), a program that focuses on repeat-offending devices is likely to be cost effective because it targets those few devices that have demonstrated a tendency to fail repetitively. Indeed, since each outage requires the utility to deploy resources to respond, if some effort can be made to fix the problem the first time (or with a single follow-up visit) the cost of the remediation may well pay for itself in short order through avoiding future restoration trips (to say nothing of the cost of dealing with customer complaints.). A criterion along the lines of reviewing all devices with 2 failures in a month (or 3 within a quarter) would seem appropriate.

URD Cable Replacement

The main reason that utilities are replacing failure-prone URD cable is to avoid customer complaints from repetitive failures and also to save repair costs. Once a cable starts to fail, the time between failures begins to accelerate. It is worth noting that the impact on SAIFI and CAIDI of a utility's entire URD replacement program, which may run from hundreds of thousands of dollars to even many millions of dollars for some utilities, is usually not very significant. This is because URD cable runs tend to involve only 10 to 50 customers, so each outage is a small one. As such, even if a utility were to experience a few hundred URD cable failures per year, it would cause less than 10,000 customer interruptions for an impact of about .02 on SAIFI for a utility with 750,000 customers like CEI. For this reason, we recommend that CEI sustain it's policy of replacement of URD cable after three failures on the same section.

1.3.2 Reduce Outage Duration

As previously stated, CEI has made a stepped improvement in CAIDI since the 2002/2003 period, closing the gap to the 2009 target by 50 percent (to approximately 128.0 minutes). This amount of improvement is indicative of an "all hands" effort, and speaks well to the teamwork and cooperation that has characterized the interactions across the various departments. That being said, the challenge to improve CAIDI by an additional 30-35 minutes is formidable, and will require continual fine-tuning of many of the practices already in place. Our analysis resulted in the following insights and conclusions:

Staff Mobilization

- With the exception of the Ashtabula line district, one of the more rural areas in the system, the overall trend in CAIDI performance from 2002 to 2006 is positive. Ashtabula represents almost half of the territory. The Company is in the process of establishing another line district (Claridon Township) (planned in-service date of 2009) to help alleviate the challenges inherent to such a large area. Combined with the new line district in Euclid in 2007, the Company is taking significant measures to improve initial response time.
- Pre-mobilization with respect to storms offers a potentially high leverage opportunity in eliminating customer minutes of interruption. By integrating all of the weather-related factors (e.g. effective wind speed, heat storms, lightning) into a common methodology, the Company can develop an empirical basis to augment the intuitive and experiential approach already being used to mobilize staff (in anticipation of a storm).
- Other staff mobilization-related practices (First Responder, Call-out, and Alternate Shift) appear to operating effectively; the most dramatic being the impact that the alternate shift has had on average outage duration during the 3:00 PM to 8:00 PM time frame (it is virtually indistinguishable from other time periods).

Work Flow

- The concept of applying partial restoration ("cut and run") appears to be a normal practice across the Company, and should definitely be continued. This is especially true on feeder backbones and large taps, even when that may involve 'cutting' perfectly good conductor in order to isolate faulted spans, so that crews can then 'run' to restore the remaining parts of the circuit.

- The Company has used the split and hit method on underground cable effectively for years; this is an industry leading practice and we recommend its continued use.

Communication

- The Company effectively employs all industry accepted norms in keeping all parties informed about the current state of restoration efforts and establishing a culture of continuous improvement through forums geared to constructive sharing of experiences and circumstances, both positive and negative.

1.4 Long Term Assessment (10-Year Vision)

The Company's long-term success depends on the Company's implementation of FirstEnergy's Asset Management-based Business Model. The Company is in the process of developing a strategy that integrates the refurbishment (and even replacement) of an aging electric infrastructure and revitalization of the Company's staff with a sound capital spending prioritization process. We believe this is foundational to the Company achieving sustained (i.e. 10 year) 1^{st} or 2^{nd}-quartile performance in reliability (as measured by SAIFI and CAIDI) and for that matter may be a critical success factor in realizing the 2009 performance targets.

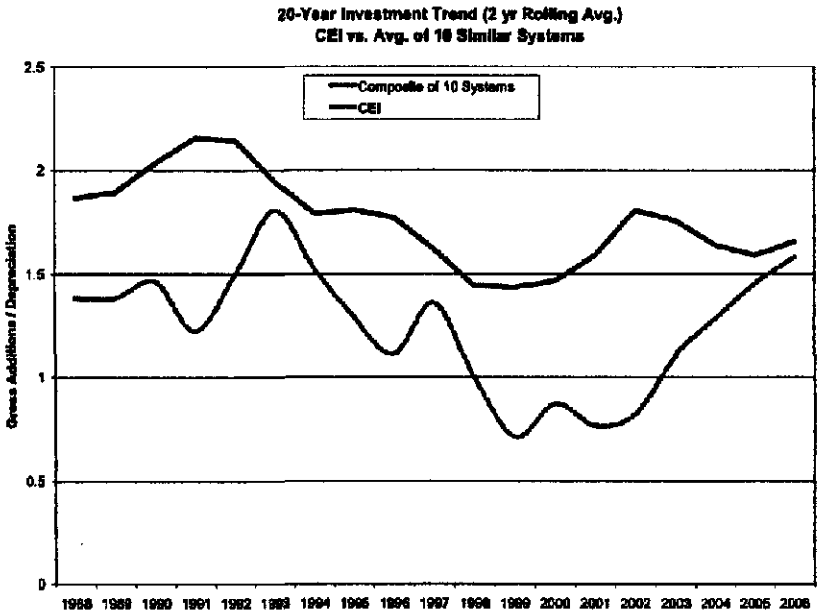
The key driver to realizing this vision is the amount of capital to be invested in the assets and then to properly allocate the capital in a manner that will yield the highest return in terms of improved performance. Therefore, the following discussion will first highlight the key points arrived at during the assessment of the Company's Capital Expenditures process and then address the issues of a deteriorating electric infrastructure and aging workforce.

1.4.1 Capital Expenditures

Level of Spending

Figure 1-8 presents a nearly 20-year trend of the ratio of *Gross Distribution Plant Additions / Depreciation* for CEI and for a composite of 10 U.S. electric utilities. The utilities in our reference composite measure were selected from similarly sized, Eastern U.S., urban/suburban systems. As discussed in Section 8.0, we selected this ratio as the most appropriate way to make relative comparisons of capital expenditures because it provides a practical and generally stable *relative* measure of investment levels among systems; moreover, it offers an indicator (albeit imprecise) of "reinvestment" in the system. To "dampen" the effect of extraordinary single year events (e.g. an extraordinary event or year), we prepared this data in a 2-year rolling average approach:

Figure 1-8
CEI Capital Spending vs. Similar Systems (1988-2006)



The implications of this comparative analysis are as follows:

- The Company's capital spending pattern over time has been consistent with the industry trends, albeit always at a *lower than average* level of spending for *all* years of this review.
- The Company has exhibited a strong investment pattern since 2003 and one that is counter to general industry trends (i.e. CEI's investment has been increasing when the industry is relatively flat). This suggests that the Company has recently sought to return to a more "normal' level of investment. In fact, the Company's 2006 capital expenditures were $69.1 million, an amount $8.1 million greater than the amount originally budgeted; and a similar pattern occurred in 2005, when CEI's actual capital expenditure was $47 5 million or $11.7 million greater than originally budgeted. Thus, we can find no evidence that FirstEnergy is "starving" the CEI system in recent years -- further confirming the conclusion that the CEI system is clearly an investment priority within FirstEnergy system of companies.
- The Company's current capital plans also suggest that this elevated level of capital investment will continue in 2008 and beyond. Further, current (relatively higher) capital expenditure levels are scheduled to be sustained over the next few years.
- At an aggregate level, the CEI electric system may require some increased investment in the coming years to "catch up" on deferred capital replacement that has likely occurred in the past 20 years.

So, from a forward-looking perspective, the Company appears to be at the "right" level of capital spending.

Commitment to Reliability

We then analyzed the capital spending from a reliability perspective, both from a priority (vs. other capital commitments) and commitment (level of funding) perspective. This review resulted in the following observations:

- Overall "reliability-related" investment in 2006 was substantial, accounting for at least one-third of the capital spending during that year. In our experience, this is a strong investment pattern when compared to other, similar systems.
- "Reliability-related" spending in 2006 was at least $8.9 million greater than originally planned. When considered in the context of the $8.1million in additional (unbudgeted) capital spending in 2006, it is clear that reliability-related investment was one of the company's highest priorities in 2006.

Thus, we conclude that the company has made a strong recent commitment to reliability-related spending in 2006 and shows evidence of similar investment patterns in 2007.

Capital Planning and Improvement Process

The assessment next shifted to evaluating CEI's capital planning processes (including Project Prioritization) to verify the extent to which they begin with a clear identification and expression of system needs or issues (expansion commitments, reliability problems, etc.), are evaluated with a systematic and risk-considered approach that is designed to achieve optimal results given reasonable constraints (seasonal scheduling, availability of specialty tools or crews, etc.), and are automated to achieve systematic and reproducible results where appropriate. In so doing, we developed the following insights:

- CEI's processes during the past few years have exhibited many of the attributes that constitute a sound planning and prioritization process. They are holistic and need-/issue-driven. The Company and FirstEnergy overall have made efforts to standardize key elements in the issue identification, project classification, and risk definition steps. Such standardization allows for automation, record keeping, and consistency of decisions.
- CEI's risk assessment scoring process could be currently described as adequate and consistent with industry standards and practices. It has a strong, reliability-focused *Impact* measurement structure. However, the risk assessment could be significantly enhanced by adding a probabilistic (rather than a substantially qualitative) estimate of the *Likelihood* measurement dimension. This is a recently added element in the planning process and should improve its overall effectiveness.
- Implementing industry best practices would lead CEI to develop integrated systems that link the investment evaluation process and subsequent prioritization and funding to overall strategy (i.e. the investments contribution to meeting strategic objectives tied to system reliability, financial return on investment, etc.) and risk mitigation. In applying an approach that disaggregates the investment decision from resource utilization considerations, CEI will make significant strides in the area of Asset Management.
- One noteworthy element of this Asset Management initiative that relates to these capital-related processes is CEI's implementation of a Capital Prioritization

process (this project was inaugurated during the 2nd quarter 2007 just as this assessment was initiated). The approach and toolset (one of several available in the marketplace) has been developed over multiple years with numerous other large, investor-owned electric utilities. Consequently, it is a proven approach, embodies many of the industry's leading practices, and should expedite the Company's development in these areas.

Capital Processes Integrity

Our assessment of the integrity of CEI's capital-related business processes focused on whether these processes have been implemented as designed. From our interviews and a review of CEI's records related to the Company's capital planning and prioritization processes, it is apparent that the processes as described by company's management and technical team are being implemented as intended. These processes have high visibility and a large number of participants in all of the varying process stages defined above. There is an appropriate documentary trail to support that its conclusions and actions are implemented as planned.

At the present time the Company lacks a rigorous data relationship capability between the RPA database (a Lotus Notes application) and the SAP system (which tracks actual project activity). Although such conditions are less than ideal, they are also not uncommon given the complexity of maintaining interfaces between enterprise-based transaction systems (such as SAP) and active, Company-developed planning tools (such as the RPA system). Consequently, it is not possible to easily track and report "end-to-end" the performance of all RPAs through construction and completion (or deferral) in an automated way. Ideally, our analysis would have included an assessment to test whether the capital plans as approved from the RPA database were implemented (wholly or partially) as they are planned in SAP (i.e. – did "approved" projects actually get built and on what schedule?) Similarly, we also would have checked the process "in reverse", to determine that all projects that were constructed do indeed tie rigorously to an RPA (or not). At the present time such an assessment is not available in an automated way.

1.4.2 Refurbishment and Replacement of Aging Infrastructure

In assessing the Company's electric distribution infrastructure, 4 substations and 15 circuits (4kV, 13.2kV and 34.5kV) were inspected with a strong bias towards worst performing circuits and substations with a recent history of equipment problems. Other than to acknowledge the age of the equipment in the substations, the more significant programmatic-related insights originated from the circuit inspections:

- The CEI inspection records were adjudged adequate in their representation of the material condition of the system. However, there were 132 exceptions noted by UMS Group (on circuits previously inspected by CEI), that were not noted in the circuit inspection records.
- 128 of the 320 open exceptions were categorized as reliability-related (i.e. vegetation, broken cross arms, severely damaged pole or damaged lightning arrester). Of those, 41 could cause customer interruptions at any time. However, the reliability concern has less to do with these specific exceptions, and more to do with the accumulated effect of an accumulating list of exceptions and the compounding impact they might have on the overall material condition of the system.

- The overall condition of CEI's electric distribution system presents a significant challenge to CEI reaching top quartile performance in SAIFI and second quartile performance in CAIDI (i.e. the industry context for CEI's current reliability targets), particularly given the mandate to sustain this performance over a ten year period. The underlying causes include:
  - ⇒ Inadequate funding for over a decade (commencing in the early-1990s), a phenomenon that was common across the industry. Every indication is that this shortfall is being addressed, but that the impact of a return to adequate spending levels will not be realized immediately.
  - ⇒ Steadily decreasing staffing levels during this same time period amidst an increasingly challenging maintenance workload (due to increased inspection activities leading to higher levels of corrective maintenance and the inherent issues of aging equipment).

  NOTE: The aforementioned insights should in no way be interpreted to lessen the importance of complying with the mandated ESSS Inspection Requirements (Rule 26) as 100 percent compliance should be the standard. It merely acknowledges the findings within the context of scope (the 15 selected circuits represented 347 miles of overhead lines/circuits and over 10,000 poles) and near term impact on system reliability (the current analysis reveals little, if any, correlation between the material condition of the assets and reliability as measured by SAIFI and CAIDI).

Recognizing a problem that has been 10-15 years in the making cannot be reversed overnight, the solution involves a number of longer term and related initiatives:

- Systematic and staged refurbishment and replacement strategy, leveraging the initiatives addressed within the newly instituted Asset Management Plan.
- Integration of the Circuit Health Coordinators with the ESSS Inspection Program (providing an over-inspection role and coordinator in addressing high-priority reliability related inspection deficiencies/exceptions), and Reliability Engineers.
- Prioritization of workload with the concept of protecting the feeder backbone and addressing circuits with multiple customer interruptions.
- Recruiting and hiring of additional distribution line and substation personnel (in advance of the planned retirement of a rapidly aging workforce) and using this temporary increase in staffing to address the corrective maintenance backlog.

As CEI implements these recommendations and integrates them with the existing comprehensive system reliability improvement program, we need to reinforce that the current infrastructure though aged and in relatively poor material condition, is not the main cause for CEI missing its reliability targets. However, to get to the performance levels called for in the current agreement between the Staff and CEI and sustain that level of performance, these issues could become the controlling factors in the future.

1.4.3 Organization and Staffing

The entire discussion to this point highlights the initiatives and practices necessary to meet the 2009 reliability performance targets and sustain that level of performance for the foreseeable future (nominally 10 years). An underlying assumption and critical success factor is the capacity and ability of the Company's staff to carry out the plan as it is integrated with the Company's strategic and operational plans. With that in mind, we performed an assessment of the Company's organization and staff, looking at it from three critical dimensions:

- **Sustainable Workforce:** Addressing CEI's ability to maintain its staffing levels and knowledge base at a level sufficient to carry out its mission with respect to system reliability.

  Table 1-9 shows the Departments/Functions/Positions that were the focus of this portion of the assessment.

Figure 1-9
Critical Staffing Categories

Department	Function	Positions
Reliability	Regional Dispatching	Regional Dispatcher
Operations Services	Distribution Line	Line Leader Shift Lineworker Leader Distribution Lineworker
	Engineering Services	Engineer Distribution Specialist
Operations Support	Substation	Relay Tester Electrician Leader
	UG Network	Underground Electrician Leader Shift Underground Electrician Leader Underground Electrician

- **Workforce Management:** Evaluating CEI's ability to keep pace with its inspection and maintenance requirements, improve outage response, and execute the capital spending plan (specifically New Business and reliability/capacity projects).
- **Reliability Culture:** Focusing on CEI's effort to ensure that its sustainable and well-managed workforce is aligned (at all levels) to the requirement to improve overall system reliability.

Current Organization and Staffing (and any enhancements) will have little if any immediate positive impact on CEI meeting its 2009 Reliability Performance Targets. However, failure to confront the issues in an urgent and comprehensive manner will compromise the Company's ability to achieve the objective of 10 years of sustained 1st and 2nd quartile reliability performance.

The three elements of organization and staffing are obviously interrelated in that a sustainable workforce, properly staffed and aligned to the priorities of the organization will balance the inspection and maintenance, outage response, and capital project requirements. In terms of current status across these three dimensions, there are two areas that we consider critical in support of the long-term vision:

- The challenge of replacing a rapidly aging work force within a fairly tight O&M budget; and
- The need to address the CM backlog across all line districts.

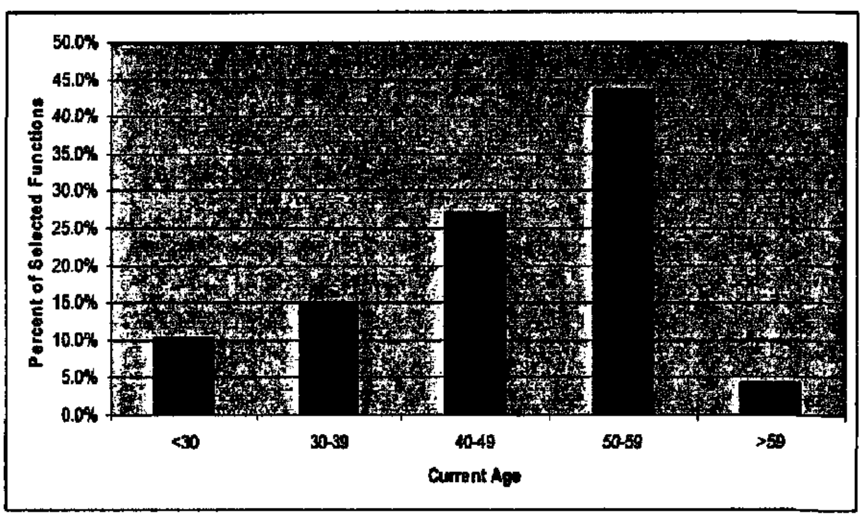
Aging Work Force

Figure 1-10 below presents the age profile of the staff within each of the functions shown in the above table (Figure 1-9). Over 48 percent (308 employees) are 50 years of age (or older) and are likely to retire within the next 10 years. The current policy of maintaining a one-for-one hiring policy with respect to managing attrition is certainly valid when doing "like for like" replacements in terms of experience, knowledge, and leadership acumen. The reality is that the Company is replacing the more seasoned individuals with "entry level" hires. Though the PSI program provides an outstanding foundation for a new hire, it does not replace the 3-5 year apprenticeship period necessary to become fully productive in the field, let alone the value provided by someone with over 20 years of field experience.

The impact of this dynamic is already being felt among the Regional Dispatchers where 35 percent of the staff has less than 2 years experience. This cannot help but have a short term negative impact on service restoration.

Figure 1-10
CEI Employees by Age and Function

Function	Current Age					Total
	<30	30-39	40-49	50-59	>59	
Substation	13	7	29	60	11	120
Distribution Line	42	60	96	152	14	364
Underground Network	1	11	16	25	0	53
Engineering Services	6	10	20	33	3	72
Regional Dispatching	5	6	13	10	0	34
TOTAL	67	94	174	280	28	643
PERCENTAGE	10.4%	14.6%	27.1%	43.5%	4.4%	



Related to the issue of an aging workforce is the fact that over 55 percent (38 of 68) of the current Leadership and Management staff in these targeted areas is also likely to retire within this same 10-year time period. The pipeline for future Leaders and Managers is typically composed of the Non-Managers (included in Figure 1-10) that currently range in age from 30-39); this pipeline is clearly constrained.

To mitigate these effects FirstEnergy has taken a number of steps to address this challenge, most notably the PSI Program. The PSI program could certainly be categorized as an industry "Leading Practices" approach to recruiting, training, and assimilating entry level employees. The challenge is the pace at which this staffing shortfall, a decade in the making, can be addressed. This is particularly acute given the other realities of budget and headcount constraints and general availability of labor. Unfortunately, there is no shortcut to developing future leaders and managers. This will require an aggressive outside recruiting effort, coupled with a well-conceived leadership and management development program.

Corrective Maintenance Backlog

Figure 1-11 portrays our assessment of the Company's performance across the major work streams that compete for resources on a day-to-day basis. In short, CEI has maintained a fairly good balance, with one notable exception: Distribution (Line) Corrective Maintenance. There are a number of parallel actions to take in addressing this shortfall:

- Explore opportunities to out-source more capital project work, thus freeing up the distribution line resources to address open exceptions/deficiencies identified during the circuit inspections.
- Establish a more effective prioritization process with respect to identified deficiencies/exceptions ranging from highest priority (reliability and/or safety related) to inconsequential (no action required).
- To the extent that an accelerated hiring program is instituted, apply the temporary "excess staff" to closing out the CM backlog.

Figure 1-11
Workforce Management Assessment

Measure	Performance	Comments
Substation Preventive Maintenance		Significant PM Backlog on track for resolution by EOY 2007 (with existing staff levels)
Distribution Line Preventive Maintenance		Mix of in-house staff (light duty personnel) and staff supplementation with contractors (former CEI employees)
Substation Corrective Maintenance		Current staff able to keep pace with exceptions identified during substation inspections
Distribution Corrective Maintenance		Significant backlog. Resolution hinges on accelerated Senior level replacement strategy/increase in contracted work
Outage Response		Steady improvement in response time (CAIDI) noted since 2003
Capital Spending		On track. Increase in contracting Capital Projects will free CEI resources to address Corrective Maintenance

LEGEND

ON TRACK

CAUTION

DANGER

1.4.4 Asset Management

The issues relating to capital expenditures, refurbishment/replacement of an aging infrastructure, and organization and staffing will be comprehensively and programmatically addressed as the Company transitions to the Asset Management Business Model. Our overall interpretation of this more global initiative in the context of the reliability assessment is straightforward – we believe it absolutely represents the greatest opportunity for the Company to make rapid, cost-effective, and truly sustained improvement in electric system reliability. At the same time, we also believe it represents perhaps the single greatest risk to overall system reliability because of the potential uncertainties created by any major organization restructuring and new processes.

Figure 1-12 below summarizes some of the major risks and opportunities that CEI will face as it develops its Asset Management organization:

Figure 1-12
Opportunities & Risks of First Energy's Asset Management Initiative

Opportunity	Risk
FirstEnergy-wide "best thinking" and "best practices" applied to the CEI system	Local technical and reliability expertise is diminished by a strong centralizing reorganization
Economies of scale asset data analysis, systems & tools, and equipment purchases	Unnecessary data collection not linked to key asset reliability decisions
Circuit Health Coordinators (CRCs) with strong, local accountability for circuit performance.	Inadequate skills and qualifications of CRCs in a critical role; diminished sense of accountability in other departments
Vastly improved asset data and inspection performance.	Uncertain or unclear organizational relationships for or interfaces with new functions

This initiative is simply in too early a stage to make any formal assessment of its effectiveness or impact on CEI's overall reliability. However, we recommend that this initiative be actively monitored for impact and effectiveness over the next 12-24 months.

1.5 Summary of Recommendations

The following recommendations present our view of the actions that will bring CEI into compliance with the 2005 ESSS Rule 10 Action Plan (and more specifically to meet the 2009 SAIFI and CAIDI targets). Many of these items have already been initiated or implemented, providing further evidence of the sense of urgency and importance CEI assigns to meeting these commitments. Sections 2.0 through 8.0 of this report not only expand upon the factors that drive these recommendations (offering additional suggestions and insights related to positioning CEI as an example of "best practices" in the area of electric system reliability), but they also address in more detail the challenges and opportunities related to achieving the longer-term 10-year vision.

Note that the "Impact" described in the table below combines the potential of a specific recommendation to impact reliability (as measured by SAIFI and/or CAIDI) with our assessment of the current capabilities of the CEI staff. As the Company's expertise and associated competencies improve (particularly in the area of lightning protection), these initiatives can yield further improvements in overall reliability.

The Tier 1 initiatives summarize the impact and estimated cost of actions where the Company will achieve the highest "value" for the capital and/or O&M dollars expended. The Tier 2 initiatives outline the next level of actions to fully address the current gap (and then some) between the 2006 performance and the 2009 targets. Figure 1-13 provides a tabulation of the impact and associated incremental costs:

Figure 1-13
Reliability Impact and Cost Summary

	SAIFI		CAIDI	
	Impact	Cost	Impact	Cost
Tier 1	(.17)	$5.8M	(20 minutes)	$0.225M
Tier 2	(.13)	$17.6M	(5 minutes)	$0.100M
Total	**(.30)**	**$23.4M**	**(25 minutes)**	**$0.325M**

For SAIFI we recommend (as a minimum) adopting all the tier one actions and the tier 2 actions for sectionalizing the feeder backbone (SI-4). This presents the most cost-effective solution as this combination of Tier 1 and Tier 2 results in a projected SAIFI reduction of 0.20 from 2006 actual performance at an incremental cost of $7.8 million. For CAIDI we recommend implementing all the actions summarized in Section 1.5.2 and discussed more comprehensively in Section 6.5, resulting in a reduction of 25.0 minutes at an incremental cost of $325,000.

In terms of establishing the baseline from which to measure the SAIFI and CAIDI impacts, we have adopted the following approach (working in conjunction with CEI Management):

- CEI's 2006 SAIFI performance was 1.17 (almost identical to the 12-month rolling measure as of the end of September 2007). Therefore, we suggest maintaining the 2006 performance level as the SAIFI baseline.
- CEI's 2006 CAIDI performance was 128.3 minutes. CEI has, in fact, implemented a number of improvement measures over the past few years that have yielded significant improvement to CAIDI (the Year-to-Date CAIDI for 2007 is 105.5 minutes). Admittedly, 2007 has been a "good" year in terms of storms (particularly those "minor storms" that almost reach the threshold for exclusion); thus, it would not be prudent to use that figure as the baseline. However, applying a historical perspective to this year's performance level, one can normalize the 105.5 minutes to a more representative and conservative number (from which to apply the impacts of these recommendations). Since a "typical" year" has, on average, 4 storms that do not quite make the threshold criteria for a major storm (i.e. excludable); and there have been none in 2007, we suggest adjusting the CAIDI baseline to 120.0 minutes (assumes 4 storms with the average experienced CAIDI impact of 3 to 4 minutes).

Therefore, full realization of these recommendations will result in an estimated overall SAIFI of less than 1.00 and a CAIDI of 95.0 minutes. Informed readers should recognize that there are a number of other factors that could impact the bottom-line achievement of these goals that have no relation to the effectiveness of these recommendations (particularly with respect to CAIDI). It is quite probable that as CEI adopts these recommendations, these other variables will come into play. For example, the reduction of subtransmission, substation, and backbone outages could shift the mix of outages from those of relatively short duration to those with longer duration. In a sense, the success of the SAIFI initiatives can negatively impact progress on CAIDI. These types of effects can be analyzed and accounted for should they occur, adding more emphasis to the importance of close communication and coordination between CEI and the Staff to ensure a constructive dialogue that acknowledges accomplishments and promotes joint problem-solving should these variances be realized.

1.5.1 SAIFI Improvement Recommendations

(Refer to Section 5.5 for more discussion around the proposed actions)

ID No	Action	Tier	SAIFI Impact	Incremental Cost	Completion Date
SI-1	Enhanced Tree Trimming	Tier 1	(.026)	$1M ($48 per CI avoided)	12/31/2008
		Tier 2	(.020)	$3M ($200 per CI avoided)	NOTE 1
SI-2	Lightning Protection	Tier 1	(.010)	$1M ($133 per CI avoided)	12/31/2008
		Tier 2	(.067)	$11.3M ($225 per CI avoided)	NOTE 1
SI-3	Line/circuit inspection and repair prioritization scheme	NA	(.035)	$0.5M ($19 per CI avoided)	12/31/2009
SI-4	Sectionalize the Backbone	Tier 1	(.093)	$2M ($29 per CI avoided)	9/30/2008
		Tier 2	(.033)	$2M ($59 pre CI avoided)	5/31/2009
SI-5	Replace three-phase reclosers with single-phase reclosers	NA	Negligible Based on Number Planned for 2007	$20K per Retrofit and $125 per CI avoided	NOTE 2
SI-6	Selectively apply instant trip/ timed re-close	NA	33 circuits with instant trip off	No incremental cost	NOTE 2
SI-7	Inspect, maintain, test and repair/replace as necessary 4kV exit cable	Tier 1	(.01)	$1.3M ($159 per CI avoided)	12/31/2008
		Tier 2	(.005)	$1.3M ($397 per CI avoided)	
SI-8	Use Worst Performing Devices information to develop a worst-CEMI program	NA	Limited Impact (Customer Satisfaction)	Additional cost not related to improving SAIFI	NOTE 2
SI-9	Replace failure-prone URD cable	NA	Limited Impact (Customer Satisfaction)	Additional cost not related to improving SAIFI (already budgeted)	NOTE 2
SI-10	Integrate the Circuit Health Coordinators with the ESSS Inspection Program	NA	CI Avoidance	No incremental cost (previously budgeted)	NOTE 2
SI-11	Continue to address the operability of switches on the subtransmission system	NA	Prevent deterioration of subtransmission SAIFI	No incremental cost (previously budgeted)	NOTE 2
SI-12	Continue to replace circuit breakers and relays at the substations	NA	Prevent deterioration of substation SAIFI 5 breaker replacement projects scheduled for 2008 – expected SAIFI improvement of (0.014)	No incremental cost (previously budgeted) $1.0M for 5 breaker replacement projects	NOTE 2

NOTE 1: Our initial recommendation acknowledges that the cost-benefit trade-offs for these tier 2 actions do not warrant CEI action at this time.

NOTE 2: These actions are either situational (with little or no anticipated impact to overall system reliability) or already in full implementation (where any incremental improvement to SAIFI has largely been realized). They are provided for purposes of management visibility as they are viewed as complimentary (necessary) to the 2009 objectives.

1.5.2 CAIDI Improvement Recommendations

(Refer to Section 6.5 for more discussion around the proposed actions)

ID No.	Action	Tier	CAIDI Impact	Incremental Cost	Completion Date
SR-1	Systematize staff Pre-mobilization	Tier 1	(6 minutes)	$100,000 ($2.22 per 100 CMI	6/30/2008
		Tier 2	(5 minutes)	$100,000 ($2.66 per 100 CMI)	6/30/2008
SR-2	Fully implement partial restoration for OHL ("Cut and Run") and URD ("Split and Hit")	NA	(4 minutes)	$125,000 ($4.17 per 100 CMI)	NOTE 3
SR-3	Fully implement use of the alternate shift	NA	(4 minutes)	No incremental cost	NOTE 3
SR-4	Recruit/Train New Dispatchers	NA	NOTE 4	No incremental cost	NOTE 3
SR-5	Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007)	NA	(1 minutes) in 2008/2009 Additional (2 minutes) after 2009	No incremental cost (already included in the budget)	12/31/2009
SR-6	Reevaluate Level of Staffing with respect to outage response	NA	NOTE 4	Undetermined	NOTE 3
SI-1 to SI-7	Impact of CI reduction on CMIs	NA	(5 minutes)	Defined within SI-1 to SI-7	12/31/2008

NOTE 3: These actions are already in full implementation; improvement in both areas is called for, requiring constant reinforcement and monitoring.

NOTE 4: The impact on CAIDI is indeterminate in that the intent of these actions is to proactively avoid a negative impact to CAIDI

1.5.3 Long-Term Recommendations

The foundational elements that comprise an integrated approach to realizing sustained performance over a 10-year period are discussed in Sections 7.0 and 8.0 of this report. As such, the benefits to be derived in terms of SAIFI and CAIDI cannot be specifically quantified, nor are they necessarily "an action". In fact, these specific initiatives are properly categorized as key elements to the Asset Management Strategy just being formulated at the FirstEnergy level and are being implemented within the Operating Companies as this report was being prepared. They are being listed here for the purpose of establishing visibility and to ensure the linkage of this strategy to the overall result of this assessment:

- Maintain Capital Spending at the level currently planned for 2008 ($84.7 million) for a minimum of 5 years. Note that this budget level includes both Transmission and Distribution.
- Establish and adhere to "Reliability-related" investments (which could include capacity projects as well) at levels, percentage-wise, commensurate to those for 2007.
- Consistent with the development of the Asset Management Strategy develop a comprehensive plan to replace and/or refurbish the current electric distribution infrastructure, while in parallel implementing the shorter-term reliability measures identified in Sections 1.5.1 and 1.5.2.
- Accelerate hiring to facilitate the assimilation of new personnel in advance of anticipated attrition (due to retirement). CEI's plans to increase head count by 50 in 2009 (payroll increase of $2.5-3.0 million) and then maintain pace with attrition presents a rationale approach to the challenge of replacing an aging work force while remaining committed to the PSI program. In fact, the increase in headcount will provide a 2-year acceleration with respect to replacing senior staff (refer to Figure 7-22).
- Work cooperatively with the Staff to redefine the ESSS Inspection Requirements (focus, frequency and follow-up of exceptions) so that they more appropriately align with achieving the 10-year vision.

1.6 About UMS Group

UMS Group is a private consultancy headquartered in Parsippany, New Jersey. Founded in 1989, UMS Group also has offices in the United Kingdom, Dubai, and Australia. UMS Group has served more than 300 utility clients around the globe.

The website www.umsgroup.com provides extensive information about the company, its services, clients, and experience.

The UMS Group project team for this assessment was composed of the professionals described in the following subsections.

1.6.1 Jeffrey W. Cummings

Mr. Cummings is a Principal at UMS Group with extensive consulting and core business process reengineering experience with utility clients in North America.

His experience includes over 25 years of management, engineering, and marketing experience in the utility industry. His experience includes strategic and business planning and implementation, and organizational change management. Mr. Cummings has a diverse background in power generation, as well as in transmission, distribution and substation planning and design.

Prior to Joining UMS, Mr. Cummings owned and operated his own consulting practice. He also served for 11 years in various leadership capacities at a major engineering and technical services corporation. He holds a Master of Science Degree in Operations Research from the U. S. Naval Postgraduate School.

1.6.2 Daniel E. O'Neill

Dan O'Neill is President and Managing Consultant of O'Neill Management Consulting, LLC, specializing in serving utility clients. He has personally led more than fifty engagements with many of the largest utilities as his clients, and has played a leading role in T&D reliability and asset management, speaking at conferences, publishing in industry journals, and acting as a resource for his colleagues and for many in the industry.

In addition, Mr. O'Neill has over twenty-two years of industry experience, including four years as a utility financial executive and the remainder with major consulting firms serving the industry. Besides his asset management and reliability work, he has consulted on decision analysis, activity-based budgeting, work management, and information systems planning.

He holds a Ph.D. in economics from MIT, taught at Georgia Tech's College of Industrial Management, and is past president of the Atlanta Economics Club and of The Planning Forum's Atlanta Chapter.

1.6.3 James M. Seibert

Mr. Seibert is a Principal with UMS Group's Energy Delivery practice and has served as the Managing Director of its Middle East and European business unit. He has 18 years of experience as a management consultant to electric & gas utilities in the Transmission, Distribution, Customer Service and Shared Services functions. Prior to joining UMS Group in 2001, Mr. Seibert was most recently a Vice President and a Director of the Energy Delivery practice at Navigant Consulting, where he spent over 8 years leading process improvement, operations analysis, and merger integration efforts. Prior to his work at Navigant Consulting, Mr. Seibert spent 5 years as a Senior Consultant with Andersen Consulting (now Accenture) where he led projects to develop Customer Information Systems and Work Management Systems at major electric and gas utilities.

Mr. Seibert holds a Master of Business Administration degree from the University of Chicago and a Bachelor of Science degree in Industrial & Systems Engineering from the Ohio State University. He is also licensed as a C.P.A.

2.0 Electric Infrastructure Review

2.1 Purpose

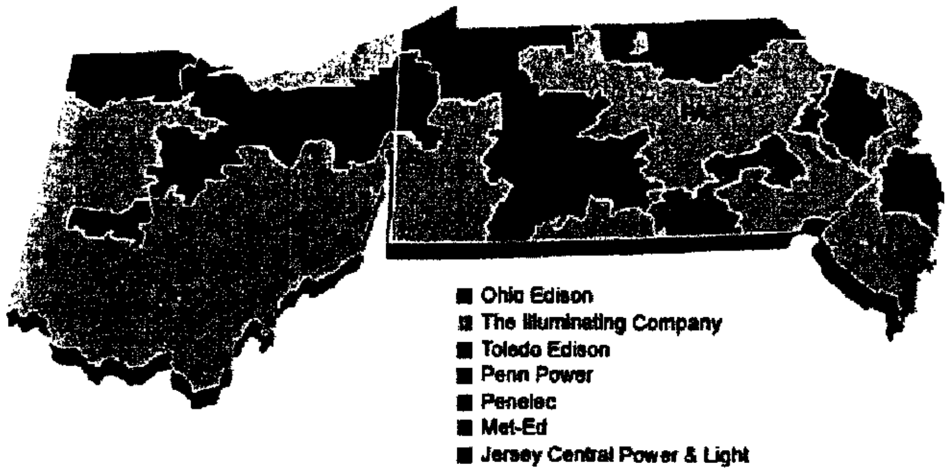
The purpose of this section of the report is to summarize our review of CEI's electric system infrastructure with a specific focus on its impact on reliability. Our approach was designed to satisfy three specific goals:

- ***Verify the accuracy of the system condition records*** via a selected sampling of records across CEI's 2 substation areas and 9 line districts. This sample was developed in a collaborative effort among UMS Group, PUCO staff, and CEI, with a bias towards inspecting the worst-performing circuits and substations. Our objective was expressly not to conduct a statistically rigorous sample of the entire system; however, the sample was intentionally constructed with a modest scale to represent as much as possible the geography, customer density, system design and voltage levels (specifically 4 kV, 13.2 kV, and 34.5kV) of the system. Presuming that we could conclude that the records accurately depict the material condition of the electric system, UMS Group would then proceed to analyze and assess the current condition of the electric system infrastructure based on a further records-only review and compare it to other similarly configured utilities using the Company's existing asset condition and health records and asset age data.
- ***Visually assess the physical condition of this same sample of system assets*** relative to industry standard. Though the majority of the system condition assessment would be made using CEI's records (provided they proved to be materially accurate as noted above), we saw this additional element as a necessary yet efficient way to augment our efforts by physically assessing the condition of the electric system.
- ***Determine the effectiveness of and adherence to CEI's Field Inspection policies and practices***. While inspecting the cross-section of substations and lines across all areas and districts, UMS Group conducted a simultaneous review of the field inspection policies and procedures (and the Company's compliance thereof) and used this review of the selected cross-section of the system to determine if the Company's policies and practices are achieving the desired outcome. The specific details of our insights, findings, and conclusions regarding this review are contained within Section 5.0 of this report.

2.2 Overview of the FE/CEI Electric System

FirstEnergy (also referred to as "FE") is a diversified energy company headquartered in Akron, Ohio. Its subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity; marketing of natural gas; and energy management and other energy-related services. Its seven electric utility operating companies comprise the nation's fifth largest investor-owned electric system, serving 4.4 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. FirstEnergy's Corporate Vision is to become the leading retail energy and related services supplier in their region.

Figure 2-1
First Energy Operating Company Territories



The Cleveland Electric Illuminating Company (The *Illuminating Company* or "CEI") serves 761,972 customers over an area that spans 1,683 square miles. Its electric system consists of over 200 distribution substations (with 640 transformers and 2,386 circuit breakers) and 1,375 distribution and subtransmission circuits with 13,874 miles (8,473 overhead and 5,401 underground) of line and 149,943 distribution transformers. This assessment focused on the following:

- 4kV Distribution: The majority of 4340V systems are within the municipal limits of the City of Cleveland and the immediately surrounding suburbs, with some "islands" outside this area where as the 4800V systems are found east of State Route 306.
- 13.2kV Distribution: The 13,200V systems are found in municipal areas that developed subsequent to 1960.
- 34.5kV Subtransmission: The 36,000V subtransmission systems are found throughout the CEI service territory except in Downtown Cleveland. They supply the larger commercial and industrial customers and distribution substations.

CEI also has a rather expansive 11kV subtransmission system (approximately 300 circuits) constructed almost exclusively as a ducted underground system providing service directly to CEI distribution substations and large three-phase customer vaults in addition to a 120/208 V secondary network. As such they have built in redundancy and are therefore rarely a source of significant number of customer interruptions. Therefore, this portion of CEI's Reliability Assessment did not address the 11kV system.

2.3 Scope and Approach

As a precursor to this review, 15 circuits were selected by totaling the number of Customer Minutes of Interruptions (CMIs) from 2002 to 2006 and noting those circuits that were candidates for a "worst-performer" classification, while ensuring proper representation across the 4kV, 13.2kV and 34.5kV distribution and subtransmission systems as well as the 9 line districts. Similarly, 4 substations were selected in consultation with PUCO staff, with a bias towards those substations with prior equipment reliability issues. Figures 2-2 and 2-3 below identify and provide key demographic information on the selected circuits and substations.

Figure 2-2
Listing of Inspected Lines and Circuits

Voltage	Circuit	OH Line Miles	No. of Poles
34.5kV	40004-0014	25	857
	40181-0019	17	529
	40159-0021	33	1026
13.2kV	50152-0030	4	163
	40109-0008	8	337
	40156-0010	6	191
	40120-0019	4	206
4kV	40024-0003	39	553
	40218-0002	92	2823
	40132-0003	12	532
	40141-0006	10	390
	40049-0001	9	358
	40052-0003	10	455
	40190-0001	68	1364
	40124-0003	10	403
	TOTAL	**347**	**10,187**

Figure 2-3
Listing of Selected Substations

Substation	Description	Number of Transformers	Number of Breakers
40169	138/36kV	9	33
40180	13kV	2	6
40126	13kV	1	5
40092	4kV	3	10
	TOTAL	**15**	**54**

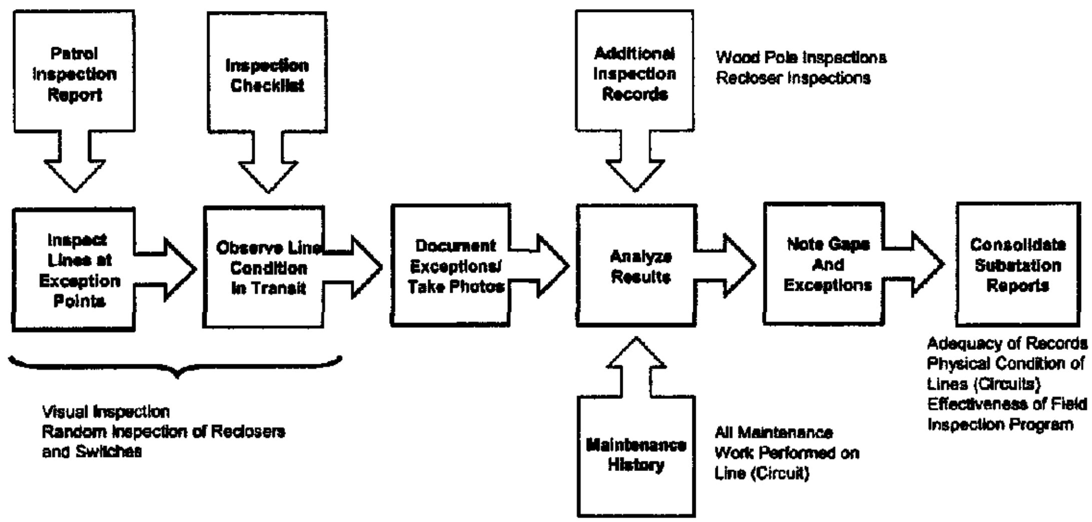
We conducted this inspection through a process that included standardized inspection checklists (refer to Section 2.6 for the format of these checklists) for both the Lines/Circuits and Substations inspections to enhance the accuracy and comparability of our results.

2.3.1 Line/Circuit Inspections

UMS Group conducted an overall visual inspection of the lines/circuits with a random inspection of reclosers and switches. Figure 2-4 below provides a description of this process where the most recent patrol inspection report was used in conjunction with the UMS Group inspection checklist to identify, document, and photograph exceptions. These results were then compared with the various company inspection reports (Wood Pole and Reclosers) and Maintenance Records to assess the completeness and accuracy of the Company's records.

Figure 2-4 below summarizes the inspection and analysis process.

Figure 2-4
Lines / Circuits Inspection and Analysis Process



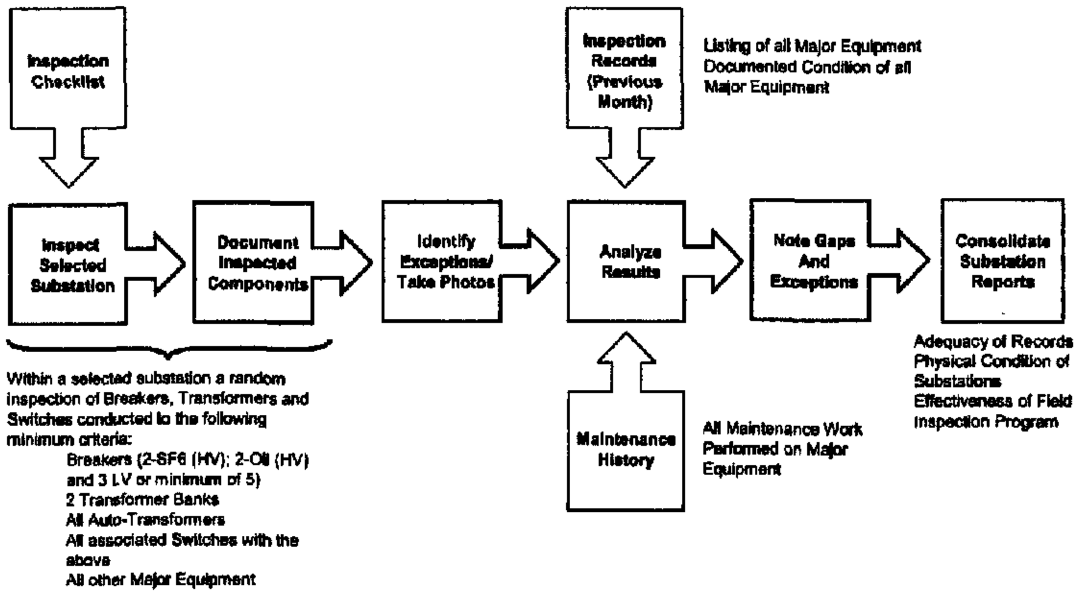
2.3.2 Substation Inspections

UMS Group systematically performed a random inspection of circuit breakers, transformers, and switches adhering to the following minimum criteria:

- Breakers: 2-SF6 (HV); 2 Oil (HV) and 3 LV (or minimum of 5)
- 2 Transformer Banks
- All Auto-Transformers
- All associated Switches with the above

Figure 2-5 below outlines the process that we followed in assessing the adequacy of records, the physical condition of the substations, and the effectiveness of the Field Inspection Program (discussed further in Section 5.0). As with the Lines/Circuits Inspections, all noted exceptions were documented (photographs were taken) and compared with the Company's existing inspection and maintenance history. In so doing, exceptions were noted, compared with the inspection records (to verify that they had been previously identified), and correlated to the maintenance records (to gain insights into the Company's follow-up activities that result when discrepancies are identified).

Figure 2-5
Substation Inspection and Analysis Process



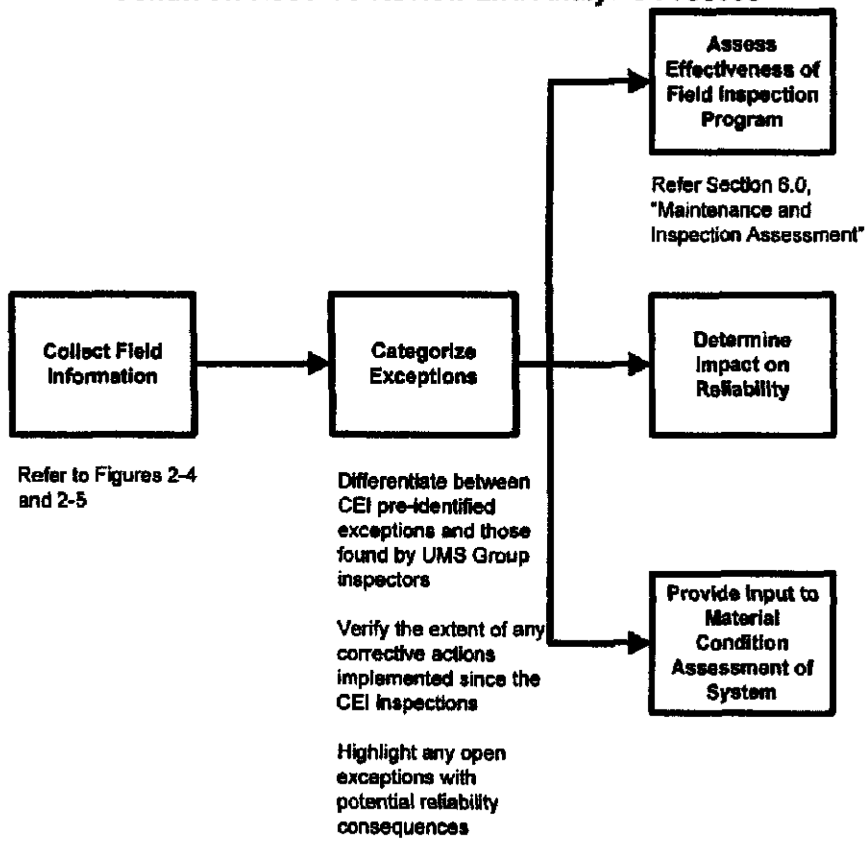
2.4 Results of the Assessment

In assessing the overall results of this review our comments here are focused on the adequacy of the inspection records and the material condition of the assets from the view of their impact to overall system reliability. The challenge was to develop a methodology that effectively answered the following questions:

- Can the inspection records (and as an extension all electric distribution records) be used to accurately assess the material condition of the assets?
- Are there any insights, recommendations, and conclusions that can be developed from this information to address the overriding objective of improving overall system reliability (as measured by SAIFI and CAIDI).

Figure 2-6 below provides a high level view of the process we followed to accomplish this charter. Its objective was to translate raw field inspection data into information and then develop a number of insights and conclusions.

Figure 2-6
Condition Records Review and Analysis Process



2.4.1 Summary of Results

Figure 2-7 below provides a tabular view of the lines/circuits inspection exceptions (and exception discrepancies). Among the sampled circuits there were originally 303 exceptions identified by CEI inspectors across the 15 circuits. The UMS Group inspectors noted an additional 132 exceptions on these same circuits. Thus, at the time of our inspection a total 320 remaining exceptions (CEI had addressed 115 of the original 303 exceptions) existed on the sample circuits. Of these "open" exceptions, 128 were identified as having a potential impact on reliability (e.g. vegetation management, broken cross arm/cross arm laying on a conductor, damaged pole, or damaged lightning arrestor).

Figure 2-7
Lines/Circuits Inspection Results

Voltage	Circuit	CEI INSPECTIONS					UMS ASSESSMENT		
		CEI Inspection Date	Pre-Identified Exceptions	Pre-Identified Corrected	Pre-Identified Uncorrected	Past Due Uncorrected	UMS Exceptions Found	Total Remaining Exceptions	Open Reliability Exceptions
34.5kV	40004-0014	9/1/2004	0	0	0	0	23	23	14
	40181-0019	3/7/2006	22	19	3	NA	14	17	17
	40159-0021	2/11/2005	7	5	2	2	3	5	5
13.2kV	50152-0030	7/10/2007	6	0	6	NA	0	6	4
	40109-0008	12/1/2005	53	13	40	40	19	59	9
	40158-0010	7/1/2003	49	19	30	30	13	43	22
	40120-0019	3/7/2006	0	0	0	NA	13	13	11
4kV	40024-0003	3/1/2006	1	0	1	NA	6	7	7
	40218-0002	4/1/2006	101	18	83	NA	14	97	16
	40132-0003	9/8/2004	3	3	0	0	1	1	0
	40141-0006	7/1/2005	17	17	0	0	4	4	3
	40049-0001	6/1/2003	13	2	11	11	14	25	12
	40052-0003	7/10/2007	5	0	5	NA	5	10	3
	40190-0001	2/20/2007	16	10	6	NA	0	6	2
	40124-0003	11/1/2005	10	9	1	1	3	4	3
TOTAL			303	115	188	84	132	320	128

Figure 2-8 below shows that the substation condition records are more than adequate. Of the 11 pre-identified exceptions (i.e. reported by CEI inspectors), all but 3 had been corrected by the time of our independent review. Furthermore, the 8 exceptions found by UMS Group are typical findings for the monthly inspection cycle (e.g. oil leaks and high/low oil) and there are no reliability related exceptions noted for the 4 inspected substations.

Figure 2-8
Substation Inspection Results

Substation	CEI SUBSTATION INSPECTIONS							UMS ASSESSMENT		
	CEI Insp Date	Number of Transformers	Number of Breakers	Pre-Identified Exceptions	Pre-Identified Corrected	Pre-Identified Uncorrected	Past Due Uncorrected	UMS Exceptions Found	Total Remaining Exceptions	Open Reliability Exceptions
40169	7/10/2007	9	33	7	5	2	0	7	9	0
40180	7/10/2007	2	6	2	2	0	0	0	0	0
40126	7/10/2007	1	5	1	1	0	0	1	1	0
40092	7/11/2007	3	10	1	0	1	0	0	1	0
	TOTAL	15	54	11	8	3	0	8	11	0

The positive outcome of the initial inspection results in substations suggested that our attention should focus further on the less favorable outcome in Lines / Circuits. Consequently, the remainder of this discussion will focus on distribution lines and circuits.

Figures 2-9 and 2-10 below provide two views of our further analysis. First, an analysis of those exceptions that could cause customer interruptions by voltage (specifically 34.5kV, 13.2kV and 4kV) and second, a review of the year the lines/circuits were last inspected.

Figure 2-9 below present the exceptions by voltage class and type. At first glance there seems to be little, if any, systematic differentiation of inspection results among the different voltage levels.

Figure 2-9
Reliability Related Exceptions by Voltage Class

Voltage	# Poles	RELIABILITY RELATED EXCEPTIONS				Total
		Vegetation Management	Cross Arm (Broken or Conductor)	Damaged Pole	Damaged Lightning Arrestor	
34.5kV	2412	4	26	3	3	36
13.2kV	897	18	24	3	1	46
4kV	6878	14	16	10	6	46
TOTAL	10187	36	66	16	10	128

Figure 2-10 below presents the distribution of exceptions based on the year the lines/circuits were last inspected. It also appears somewhat inconclusive. Obviously, the existence of any exception that could lead to a customer interruption is a concern; particularly those on circuits inspected during 2003-2005 that were previously identified with reliability related exceptions and remain uncorrected. However, in the context of 347 miles of OH lines/circuits and 10,187 poles, the number of reliability related exceptions noted (128) is not considered of sufficient quantity to warrant overriding attention. The greater concern is the accumulated effect of many exceptions system-wide, their effect on the overall material condition of the system, and the long term impact on CEI meeting the reliability targets and maintaining them for a 10-year period.

Figure 2-10
Reliability Related Exceptions by Inspection Date

Last Inspection	# Poles	RELIABILITY RELATED EXCEPTIONS				TOTAL
		Vegetation Management	Cross Arm (Broken or Conductor)	Damaged Pole	Damaged Lightning Arrestor	
2003	549	17	10	6	1	34
2004	1389	1	10	1	2	14
2005	2156	5	11	3	1	20
2006	4111	10	33	4	4	51
2007	1982	3	2	2	2	9
TOTAL	10187	36	66	16	10	128

Maintaining the focus on the open exception items that could potentially impact reliability (and more specifically those exceptions that can cause customer interruptions), the 128 reliability-related exceptions were reviewed and prioritized based on whether they pose an "immediate" threat to system reliability. In reviewing the inspection reports (and photographs), the existence of a conductor on a cross arm, a broken cross arm and inoperable lightning arrestor were highlighted as higher priority than the other exceptions.

The results of this review are highlighted in Figure 2-11 below.

Figure 2-11
Reliability Related Exception Analysis

Exception	MOST RECENT CEI INSPECTION				
	2003	2004	2005	2006	2007
Conductor on Cross Arm	1	0	0	4	1
Broken Cross Arm	2	7	5	11	0
Arrestor Open	1	2	1	4	2
TOTAL	**4**	**9**	**6**	**19**	**3**
Open Reliability Exceptions	**34**	**14**	**20**	**51**	**9**
Open Exceptions	**68**	**24**	**72**	**134**	**22**

The conclusion is that of the 320 open exceptions (combined CEI and UMS Group inspections) noted on the 15 selected circuits, 128 were categorized as reliability related; 41 of which are significant enough to potentially cause an outage.

2.4.2 Adequacy of System Condition Records

As a result of their general level of completeness and accuracy, UMS Group validated the assumption that an assessment of the current condition of the electric system infrastructure can be based on a records-only review (rather than a further, detailed field inspection effort). Based on this interpretation we present the following additional conclusions:

- **Line/Circuit Inspections:** The CEI line/circuit-related inspections (ranging from 2003 to 2007) did not capture all material exceptions and point to a need to "tighten up" the Field Inspection Program. However, it is our view that 132 exception discrepancies (in the context of 347 miles of overhead lines/circuits and 10,187 poles represented by the inspection sample) do not compromise the insights developed from these and other records regarding the material condition and/or reliability of CEI's electric distribution system.
- **Substations:** With respect to substations, UMS Group identified 8 potential discrepancies (i.e. items not previously noted on CEI's inspection reports). Due to the nature of these exceptions (oil leaks and low or high oil levels), it is quite likely that these occurred during the time period since the last inspection.

Though the discrepancies noted in this section will likely have a negligible impact on overall system reliability (in the short term), they have a more strategic imperative with longer range implications on system reliability. The Company recognizes this and is taking action to improve its performance in this area as part of the ongoing Asset Management (AM) implementation. A key component to this initiative is the collection and analysis of asset health data. With the introduction of the newly commissioned Circuit Reliability Coordinators (CRC) role as part of the AM initiative, CEI has an opportunity to improve these inspections.

FirstEnergy has also formed a new corporate department – Policy, Process, Procedures & Assessment (PPPA). This department will be responsible for developing detailed procedures across many of the FirstEnergy policies and processes (including Distribution Inspection and Maintenance Practices), and will establish and monitor performance assessment points within the established procedures.

2.4.3 Material Condition of the Assets

The overall condition of CEI's electric distribution system (based on our records review of the Company's infrastructure) presents a significant challenge to CEI reaching top quartile performance in SAIFI and second quartile performance in CAIDI (i.e. the industry context of CEI's current reliability targets), particularly given the mandate to sustain this performance over a ten year period.

Based on our review of the most recent CEI System Assessment, the following major asset condition areas will need to be addressed:

- Staged upgrading and/or replacement of transformers, particularly those built with GE Type U bushings.
- Replacement of substation equipment in many of the 4kV substations (and a few 36kV substations) due to concerns regarding the availability of replacement parts.
- Pre-1930 vintage manholes (there are over 9300 manholes in the system with a median age of 75 years).
- Addressing pre-WWI vintage conduit systems that are experiencing problems with deterioration of fiber ducts.
- Addressing over 1,600 circuit miles of the 4kV, 11kV, and 36kV underground system that is primarily cabled with non-jacketed 3-conductor PILC (with a median age of over 60 years). With an anticipated continually increasing failure rate (currently experiencing 5-7 failures per 100 circuit-miles annually), these systems are being systematically upgraded.
- Distribution Wood Poles have a median age of 32 years (over 350,000 in the system) and are experiencing a reject rate of about 4.3 percent.
- Subtransmission Wood Poles have a median age of 40 years (over 20,000 in the system) and are experiencing a reject rate of about 9 percent.
- UD Cable is being replaced at the third failure in a section. There are currently over 3,300 circuit-miles of UD Cable installed in the system.
- 36kV Pole Fire Mitigation, Line Switch Maintenance/Replacement, and Aging Wood Pole Hardware is being addressed as part of the 36kV line rebuild work.

A significant contributing factor to this level of necessary asset condition-related investment has been the systematic under-investment in the electric system that occurred during the 1990s (as outlined in Section 8.0 of this report) rather than any perceived breakdown in the Maintenance and Inspection Programs. The solution will necessarily involve a well-conceived and staged revitalization program, which will be conducted as part of FirstEnergy's Asset Management Transformation initiative.

2.4.4 Reliability Impact

Though 40 percent of the 320 open exceptions represent potential causes of customer interruptions, less than 35 percent of those pose any imminent threat to overall system reliability. Though that number is not considered statistically significant in terms of impacting near-term reliability (particularly given the number of circuit-miles and poles represented by the 15 circuits), there is a concern that the accumulated effect of many exceptions will have a compounding impact, as they do contribute to the overall material condition of the system, and will eventually compromise the goal of meeting the reliability targets and maintaining them for a 10-year period.

2.5 Inspection Checklists

The attached checklists were used by the inspectors to conduct the Distribution Infrastructure Review outlined in the project work plan. The actual inspection records, including these checklists and accompanying photographs, are available upon request.

CEI Substation Inspection Checklist

Substation: **Date:**

Battery

Check electrolyte level to be proper	Yes/No	
Check and record battery voltage	Voltage	
Check battery room heaters to be on	On/Off	
Check battery grounds		
Positive	Yes/No	
Negative	Yes/No	
Check for cracked cells	Yes/No	
Overall battery room condition	Describe	

Control House

Locked/Secure	Yes/No	
Clean	Yes/No	
Switchgear		
Indicating Lights	On/Off	
Doors Latched and Tight	Yes/No	
General Condition - ok	Yes/No	

	Total Number	Type Relay	Last Tested Date
Relay Inventory			
For Breakers			
For Transformers			
For Transformers			

Describe Concerns

Breakers - LV

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Oil breakers- check oil level correct	Yes/No				
Oil filled bushings-check oil level correct	Yes/No				
Record SF6 pressure	Psi				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Breakers - HV, Oil

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Oil breakers- check oil level correct	Yes/No				
Oil filled bushings-check oil level correct	Yes/No				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Breakers - HV, SF6 Gas

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Record SF6 pressure	Psi				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Busses

Check for broken/cracked insulators — Yes/No

Describe if Yes

Check for varmint proofing — Yes/No

Describe if Yes

Visual for signs of heating,flashover,etc — Yes/No

Describe if Yes

Capacitor Banks

Check for blown fuses — Yes/No

Check for bulging/leaking capacitors — Yes/No

Describe if Yes

Check for equipment grounds installed — Yes/No

Motor Operators

		MO #	MO #	MO #	MO #
Check and record counter readings	Record				
Check heaters	On/Off				
Check for rodent problems (mice, rats, ants)	Yes/No				

Describe if Yes

Station/General Facilities

Fencing		
Grounding	Yes/No	
Washes	Yes/No	
Gates Locked	Yes/No	
Vegetation	Yes/No	
Trash	Yes/No	

Describe Concerns

Switches- HV

		Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

Switches-LV

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

Switchgear

		Breaker #	Breaker #	Breaker #	Breaker #
Indicating lights working	Yes/No				
Counter readings	Record				
Check for equipment grounds installed	Yes/No				
Rodent problems/varmint proofing installed	Yes/No				
Lighting arresters ok	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

Transformers

Item		Bank #	Bank #	Bank #	Bank #
Record LTC/Regulator counter reading	Record				
Check bushing oil levels ok	Yes/No				
Check high and low side lighting arrestors ok	Yes/No				
Main Tank and LTC oil levels	Record				
Oil Temperatures					
Hot spot - Found/Max	Record				
Top Oil - Found/Max	Record				
LTC oil - Found/Max	Record				
Check for equipment grounds installed	Yes/No				
Oil leaks					
Main tank	Yes/No				
LTC	Yes/No				
Condition of paint ok	Yes/No				
Oil spill containment condition	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

Describe any overall observations not included above.

Circuit Inspection Check List

Date: ______________

District ____________________________ **Substation** ____________________________

Structure/Pole # ____________________________ **Circuit #** __________________
Inspector: ____
Location: ____

Cross Arm Condition ______________________________
Cross Arm Brace Condition ______________________________
Pole Condition ______________________________
Insulator Condition ______________________________
Pole Leaning ______________________________
Pole Tag (Device on Pole) ______________________________
Bushing Condition ______________________________
Cutout Condition ______________________________
Arrester Condition ______________________________
Bracket Condition ______________________________
Grounds ______________________________
Guy ______________________________
Guy Guard ______________________________
Spacer ______________________________
Oil Leaks ______________________________
Vegetation Clearance ______________________________
Floating/Damaged Conductor ______________________________
Wildlife Protection ______________________________

Additional Information:

____
____
____
____
____

Reclosure Inspection Checklist

Circuit: **Date:**

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

3.0 Outage History and Cause Analysis

3.1 Purpose, Scope, and Approach

The purpose of this section is to describe our analysis of the Company's five-year history of outage events to determine the major factors that influence system reliability and identify the company's key opportunities for cost-effective reliability improvement. Our presentation of this analysis will be accomplished by a systematic review of a series of analytical tables that will show the relationships between various outage "drivers" and aspects of system performance such as:

- Year, season, time of day, and major weather conditions,
- Cause – tree (preventable and non-preventable), lightning, animal, etc.,
- Impact – number of customers affected, duration of outage,
- Type of device interrupted – circuit breaker, recloser, line fuse, transformer, etc.,
- Specific location of equipment – district, worst circuits, worst devices, and
- *Voltage, line length, overhead/underground construction*

Our overarching objective is to form a clear interpretation of the specific causes of outages at as detailed a level as the system data will allow. We will then use these insights to identify the specific actions and recommendations the Company can take to improve reliability. These detailed recommendations are presented in Sections 5.0 and 6.0 of this report, the impact and cost of which are summarized in the Executive Summary.

3.2 The Outage Database

CEI uses FirstEnergy's PowerOn application as its Outage Management System (OMS). PowerOn is a General Electric-designed product and is one of the leading OMS applications used in the U.S. electric utility industry. It was originally developed to be compatible with the SmallWorld Geographic Information System (GIS), which is also a GE application and one of the most widely used GIS products. PowerOn has also been successfully integrated with other GIS databases, as is the case with FirstEnergy (which uses Autodesk's GIS Design Server product.)

Outage Orders are completed by the CEI Dispatcher in the PowerOn OMS. Each Outage Order goes through a "Review and Approve" verification process where a supervisor reviews the Order's data integrity and approves the Order. The review includes data fields such as cause code, duration, staged restoration steps, and other criteria which are reviewed for accuracy and compared to the EMS log. Once approved, the outage records are transferred to the Enterprise Data Warehouse (EDW) for management reporting.

The structure of the CEI outage data is similar to that of typical electric utility outage databases. Specifically, the data model is organized around the outage event - which at its core consists of the following information for each outage:

- Outage ID number,
- Time Off (when the outage began, i.e. when the power went off),
- Time On (when the outage ends, i.e., when the power came back on),
- Device ID – the unique ID of the interrupting device (fuse, breaker, etc.),

- Customers Interrupted (CI) – the number of customers downstream of the device,
- Cause, and
- Comments.

From these basic fields other performance data can be computed, such as the duration of the outage and the Customer Minutes of Interruption (CMI, the product of duration and CI). Note that CI is the numerator of SAIFI (and the denominator of CAIDI) and CMI is the numerator of CAIDI (and SAIDI). Other fields that are often included are:

- Circuit, Substation, and District (which can be deduced from the interrupting device and a system configuration /connectivity model),
- Repair Done,
- Line Down Indicator,
- Major Storm Indicator (to flag which records should be included for non-storm),
- Non-Outage Indicator (for records that are ultimately judged to not fit the definition of an outage, either because they are less than 'n' minutes in duration, were due to excludable causes (Customer Equipment), or were false alarms),
- Lockout Indicator – whether the interrupting device was a circuit breaker that ultimately locked out after perhaps trying to re-close a number of times,
- Line Type Indicator – for overhead or underground construction,
- Voltage, and
- Weather – as recorded by the dispatcher for the day or period.

A noteworthy aspect of all modern outage management systems is that they allow for the distinction between an outage and its partial restoration steps. In these systems, the individual records are actually outage restoration steps (rather than an entire event), each with its own number of customers interrupted and duration and a separate ID for each step (and a common Outage ID for all steps that are part of the same outage).

The outage database provided for this analysis contained most of these fields (except for voltage, line type, and line down). In addition, FirstEnergy provided a separate database with the characteristics of each feeder, including line miles of overhead and underground, (voltage is indicated by the circuit name, e.g. L is 13.2kV, H is 4kV, V is 11kV and R is 36kV). The data provided by FirstEnergy was adequate to perform the analysis outlined in this section.

3.3 Trends in Key Performance Statistics

The focus of this analysis is on ***non-storm*** SAIFI and CAIDI performance, with a specific focus on performance for the 5-year period ending 2006. "Non-storm" is defined as all outages not part of a major storm event, which is further defined as any event where 6 percent of the Company's customers are affected during a 12-hour period (or, occasionally other events which are approved by the PUCO as "excludable"). Figure 3-1 below provides a five-year view of the key performance statistics for CEI's reliability based on the information analyzed from the PowerOn dataset noted above.

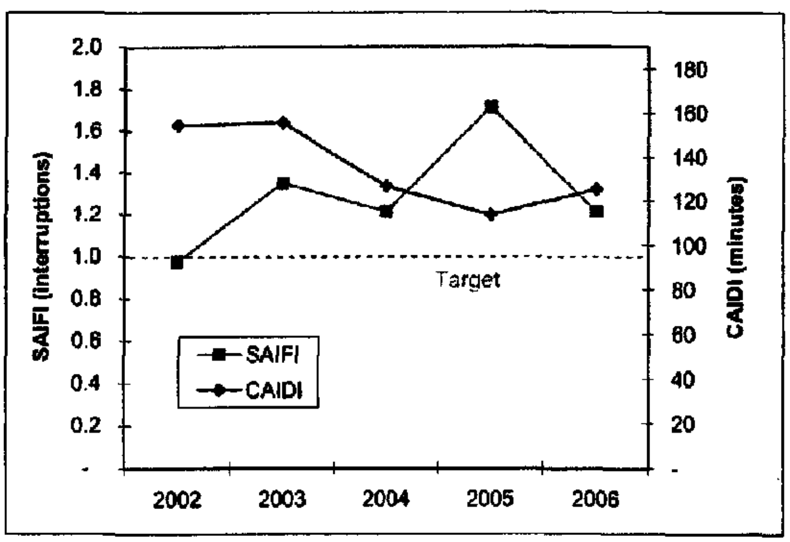
Figure 3-1
Five Year Summary of Key Reliability Measures

		2002	2003	2004	2005	2006
Outages	*Non-Storm*	*6,918*	*5,881*	*5,934*	*7,419*	*7,770*
CI	Non-Storm	717,517	932,418	846,068	1,234,999	875,992
CMI	Non-Storm	110,796,914	156,335,383	111,309,573	141,040,088	112,382,533
Customers	Served	752,666	762,226	743,595	729,838	747,026
SAIDI (minutes)	Non-Storm	147.21	205.10	149.69	193.25	150.44
SAIFI (interrupts)	Non-Storm	0.95	1.22	1.14	1.69	1.17
CAIDI (minutes)	Non-Storm	154.42	167.67	131.56	114.20	128.29

Special Note - The data shown in Figure 3-1 above originates from an updated database and does not precisely match the information reported to PUCO. The variance between this presentation and prior report is approximately 1 minute for CAIDI/SAIDI and less than 0.1 for *SAIFI*.

The non-storm SAIFI and CAIDI data from Figure 3-1 above is shown graphically in Figure 3-2 below. When this presentation is compared with the 2006 Interim Goals and 2009 Target, it is obvious that CEI needs to both eliminate interruptions (SAIFI) and improve restoration (CAIDI).

Figure 3-2
Five Year Trend in Key Reliability Measures



From Figure 3-2, except for an anomaly in 2005 when SAIFI spiked to 1.71, CAIDI steadily improved through the period to 2005 (it has since leveled out) and SAIFI has been fairly constant (ranging between 1.21 and 1.35 since 2003). While the leveling off is encouraging, the Company clearly needs to improve to reach the 2009 targets as outlined in Figure 3-3 below:

Figure 3-3
CEI Reliability Performance Targets

	SAIDI	SAIFI	CAIDI
2006 Actual	150.4	1.17	128.3
2006 Interim Goal	127.7	1.11	115.0
2007 Interim Goal	116.6	1.06	110.0
2009 Target	95.0	1.00	95.0

In reviewing the 2006 actual performance against target, it should be noted that had it not been for a storm late in the year (one that just missed meeting the storm exclusion criteria) and the major heat storm (a 1 in 50-year event) during the July 30th-August 2nd time period (also not excluded because it did not meet the 12 hour requirement), the Company would have met its 2006 Interim Goal. Figure 3-4 below further highlights this point.

Figure 3-4
2006 Storm Exception Impact

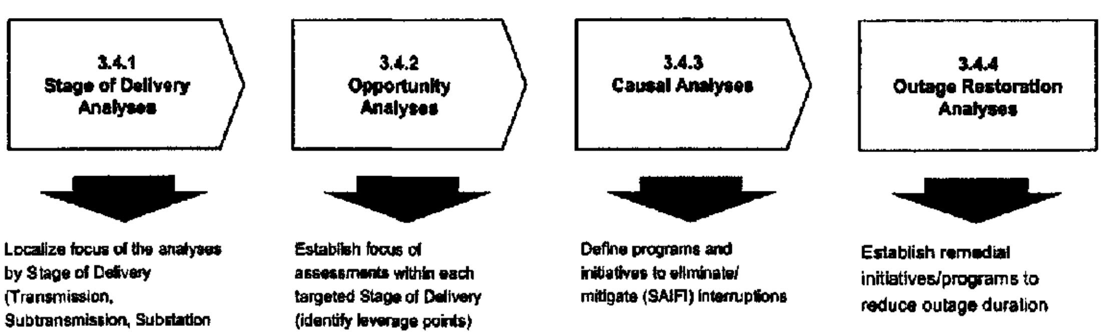
[illegible]	CI	CMI	PCNT of Customers	Adjusted SAIFI	Adjusted CAIDI
Late Storm	39,266	11,096,490	5.4%		
Heat Storm	57,028	13,873,370	7.6%		
W/O Both	96,294	24,969,860	N/A	1.05	112.4

The FirstEnergy and CEI management team fully recognizes that a "miss is a miss" and are committed to meeting the goals in spite of these "one-off" occurrences. We highlight this point only to illustrate that the gaps in performance (vs. targets) on a year-to-year basis are not always as wide (or necessarily indicative of a systematic issue) as they might at first appear. To meet the requirement of a ten-year sustainable performance level in SAIFI and CAIDI, the recommendations outlined in this report and the Company's actions will have to account for normal conditions and these "if only" or "one-off" scenarios.

3.4 Framing the Reliability Issues

Having established an overall perspective of CEI's performance relative to the reliability targets in the previous section, the next phase of this assessment involves defining the focus of the analysis (framing the reliability issues). Figure 3-5 below outlines the analysis approach that we have followed to further focus our work.

Figure 3-5
Reliability Analysis Framework



3.4.1 Stage of Delivery Analyses

When examining the reliability of an electric system, it is useful to disaggregate the system into its sub-systems ("stages of delivery") namely:

- Transmission Substations and Lines ('Bulk Power'),
- Subtransmission (mainly 36kV lines),
- Substation ('Distribution' and 'Subtransmission" Substations), and
- Distribution (Feeders, Taps, Secondary, and Services).

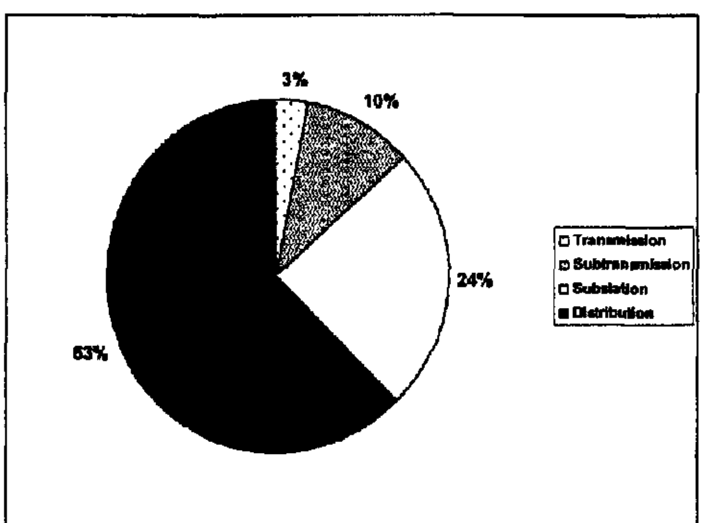
Figure 3-6 below shows a disaggregation of non-storm SAIFI performance by stage of delivery.

Figure 3-6
Trends in Non-Storm SAIFI Minutes by Subsystem

Subsystem/Stage of Delivery	2002	2003	2004	2005	2006
Transmission Substations and Lines	.02	.13	.07	.02	.04
Subtransmission	.13	.34	.23	.45	.12
Substation	.38	.36	.35	.51	.29
Distribution	.45	.52	.56	.73	.76
Total	**.97**	**1.35**	**1.21**	**1.71**	**1.21**
Distribution % of Total	**46%**	**39%**	**46%**	**43%**	**63%**

It is evident from the data above that through 2005 CEI had reliability challenges across all dimensions of distribution (subtransmission, substation and distribution circuits/lines). Moreover, recent Company efforts (most notably proactive thermal imaging, installation of SCADA controlled sectionalizers, improving the operability of the switches on subtransmission, replacing feeder breakers and relays, and improving animal protection on substations) have yielded sufficient improvement to allow us to focus primarily on Distribution (with respect to identifying additional improvement opportunities). Figure 3-7 below further illustrates that point.

Figure 3-7
2006 SAIFI by Stage of Delivery



Therefore, the remainder of this analysis will ***focus on distribution (feeders)***, noting that the initiatives already implemented for the Subtransmission and Substation stage of delivery need to continue.

3.4.2 Opportunity Analysis

The next step in disaggregating the performance of the electric system is to investigate how CEI might better focus its resources and maximize the effectiveness of its reliability improvement initiatives. We believe that five areas warrant detailed investigation:

- 'Size' of the components that experience interrupting faults (Number of Customers Impacted)
- Lockouts (Feeder Breaker Outages)
- Location of the outages (Reliability by District)
- Voltage (4kV, 11kV and 13.2kV)
- Worst Performing Circuits

<u>Number of Customers Impacted</u>

By focusing on the "size" of the components that experience the interrupting faults, our analysis segmented the outages by number of customers interrupted during an outage. At the lowest level, a single customer may have been interrupted by an outage to the service line to his premise. One level up from that is a transformer outage that typically may have interrupted a few more customers, maybe as many as ten. From there, the outage may have occurred on a small fused tap, a large fused tap, or the entire circuit. Figure 3-8 below shows the distribution of outages by the number of customers affected.

Figure 3-8
Mix of Outages by Outage Size

Customers	2002	2003	2004	2005	2006
1-10	55%	52%	51%	50%	51%
11-100	37%	36%	36%	37%	36%
Over 100	8%	12%	13%	13%	13%

It is clear from Figure 3-8 above that each year over half of all outages occurred close to the customer premise, interrupting only 1 to 10 customers. Each one of these outages often requires the same level of effort to restore service as one affecting thousands of customers, i.e., a truck must go to the site, evaluate the damage, and either make immediate repair or call for more resources to repair the damage. In other words, if a tree falls on a line and takes down the conductor between two poles, the repair required will be to replace the span, whether the number of customers interrupted is two or two thousand (as it could be in the latter case, if the span was part of the 'backbone' or un-fused main branch of the feeder).

Despite this effort, if the number of customers affected is small, there will be little (if any) impact on system reliability. These small outages need to be addressed in the context of avoiding repeat offenders (i.e. worst performing devices) to avoid customer satisfaction issues but not as part of the strategy to address overall system reliability as measured by SAIFI and CAIDI.

By contrast, as Figure 3-9 below shows, the distribution of *customers interrupted* by the 'size' of the interrupting device is skewed heavily in the opposite direction - toward the 'larger' devices. In fact, the devices that interrupt only 1 to 10 customers make up less than three percent of the total number of customers interrupted. This means that if CEI could somehow (presumably, at great expense) completely eliminate all of the 'small' outages; it would only reduce SAIFI by an almost negligible amount.

Figure 3-9
Breakdowns of Customer Interruptions by Outage Size

Customers	2002	2003	2004	2005	2006
1-10	4.3%	2.7%	2.6%	2.6%	2.6%
11-100	23.7%	17.3%	16.4%	15.4%	15.4%
Over 100	72.0%	80.0%	81.0%	82.0%	82.0%

The distribution of *customer minutes of interruption* provides the same insight as noted in Figure 3-10 below.

Figure 3-10
Breakdowns of Customer Minutes by Size of Outage

Customers	2002	2003	2004	2005	2006
1-10	5.3%	3.3%	3.4%	3.5%	3.5%
11-100	29.7%	22.7%	22.6%	20.5%	21.5%
Over 100	65.0%	74.0%	74.0%	76.0%	75.0%

Summarizing Figures 3-8, 3-9, and 3-10, we note that 51 percent of the distribution outages interrupted less than 10 customers, accounting for less than 3 percent of all distribution customer interruptions and less than 4 percent of all distribution customer minutes of interruption. Similarly, 87 percent of the distribution outages interrupted less than 100 customers, accounting for less than 18 percent of the distribution customer interruptions and 25 percent of the distribution customer minutes.

Alternatively, by focusing on a select 13 percent of the distribution outages (those affecting more than 100 customers) CEI can address over 82 percent of the distribution customer interruptions and 75 percent of the distribution customer minutes. This insight leads to the Company developing strategies where SAIFI and CAIDI improvements can be achieved by avoiding and/or mitigating the impact of 'large' outages (i.e., ones interrupting a large number of customers per outage); typically outages on the 13.2kV feeder backbone (every part of the circuit that is not behind a fuse) or very large taps and the 4kV feeders with high customer densities.

Specific initiatives that focus on these high impact improvement opportunities are discussed in more detail in Sections 5.0 and 6.0. They include initiatives aimed at:

- Hardening the feeder backbone via enhanced vegetation management, inspection and repair of pole and pole-top fault-causing equipment problems, lightning protection, and animal mitigation.

- Sectionalizing, meaning the installation of additional reclosers in targeted protection zones as well as the fusing of unfused taps.

Feeder Breaker Outages

The observation (above) that the greatest opportunity to significantly improve reliability lies in avoiding and/or mitigating the impact of large outages suggests that a further delineation of the outage data focused on circuit breaker "lockouts" may identify additional insights. Figure 3-11 below classifies the Company's 5-year history of lockouts and their relationship to outages (both number and minutes).

Figure 3-11
Five Year Impact of Lockouts

Measure	2002	2003	2004	2005	2006
Number of Outages	6918	5881	5934	7419	7770
Lockouts	222	238	223	234	323
Percent	3%	4%	4%	3%	4%
Customer Interruptions	335237	397933	414126	535487	565720
Lockouts	122647	122915	132250	128432	204230
Percent	37%	31%	32%	24%	36%
Customer Minutes	57653857	82933697	73159764	89334243	84092521
Lockouts	14468258	17164817	17179475	13168922	19307315
Percent	25%	21%	23%	15%	23%

A review of Figure 3-11 above yields the following insights:

- Of the 13 percent of the outages that impact more than 100 customers, 33 percent (4 percent of the total number of outages) were feeder breaker lockouts.
- Lockouts contributed 24 to 37 percent of all customer interruptions and 15 to 25 percent of all customer minutes. By simply reducing the number lockouts by 50 percent, all things being equal, CEI would improve SAIFI to between 0.99 and 1.06.
- In 2006, non-lockout customer interruptions fell by approximately 10 percent, but lockout customer interruptions increased by 60 percent, suggesting some changes in network protection schemes over the past few years.

Interestingly, since 2003 the percent of customer interruptions originating from lockouts does not appear to vary by distribution voltage. Figure 3-12 below highlights the impact of lockouts by voltage.

Figure 3-12
Impact of Lockouts by Voltage

Voltage	Measure	2002	2003	2004	2005	2006
4kV	Number of Customer Interruptions	236779	203391	305075	365731	389369
	Lockouts	74399	69814	93895	85488	138909
	Percent	31%	34%	31%	23%	36%
13.2kV	Number of Customer Interruptions	98234	96028	108881	169354	176158
	Lockouts	48141	52909	38263	42721	65210
	Percent	49%	55%	35%	25%	37%

Therefore, linking this portion of the analysis with the analysis of number of customers interrupted suggest the Company-led efforts that focus on both the first zone of the distribution circuits and the larger remaining sections of circuits (i.e. affecting more than 100 customers) will provide high impact improvement opportunities.

Reliability By District

Preventing and/or mitigating customer interruptions (SAIFI) is often viewed as more of a system issue. Alternatively, reducing the duration of an outage (reducing customer minutes) as measured by CAIDI is frequently and appropriately managed at the District level. Therefore, analysis of "system-wide" and "by district" reliability can often reveal additional insights. Figures 3-13, 3-14, and 3-15 below present a district-by-district view of Distribution SAIFI and CAIDI performance over the past 5 years.

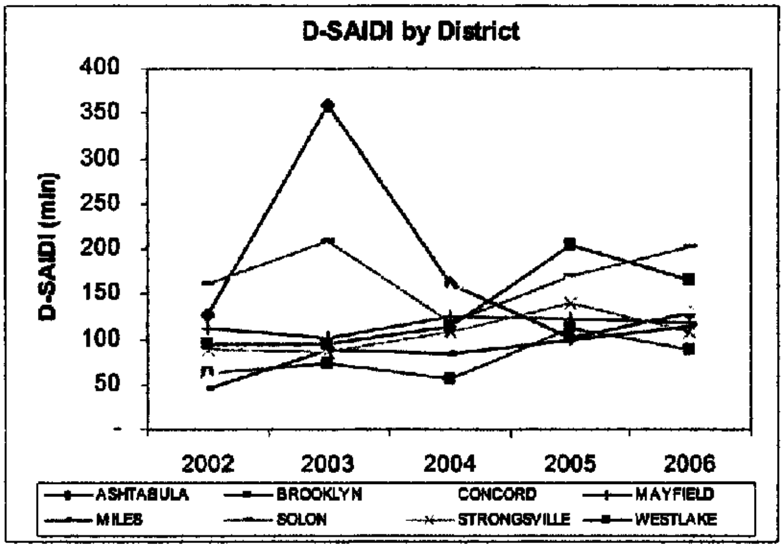
Figure 3-13
Distribution SAIFI by Line District

Reported District	2002	2003	2004	2005	2006
Ashtabula	0.90	1.41	0.94	0.67	0.67
Brooklyn	0.30	0.35	0.31	0.64	0.65
Concord	0.41	0.50	0.82	1.02	1.11
Euclid	-	-	-	-	-
Mayfield	0.65	0.58	0.69	0.75	0.82
Miles	0.25	0.44	0.46	0.63	0.67
Solon	0.75	0.82	0.68	1.38	1.50
Strongsville	0.52	0.49	0.57	0.86	0.71
West Lake	0.60	0.54	0.78	1.02	1.08
Total	0.45	0.52	0.56	0.73	0.76

Figure 3-14
Distribution CAIDI by Line District

Reported District	2002	2003	2004	2005	2006
Ashtabula	140.84	254.06	171.74	150.01	191.84
Brooklyn	212.73	211.76	180.39	175.48	136.74
Concord	147.86	206.78	187.05	170.43	121.35
Euclid					
Mayfield	173.98	177.55	181.18	164.43	143.55
Miles	183.65	202.57	183.61	155.31	170.00
Solon	213.10	255.54	172.28	123.62	134.79
Strongsville	171.14	174.50	188.14	163.01	150.04
West Lake	156.30	173.65	148.17	200.38	153.70
Total	171.98	208.41	176.66	166.83	148.65

Figure 3-15
Distribution SAIDI by Line District



The overall trend shows a deterioration of SAIFI across all districts (except Ashtabula) and a fairly steady improvement in CAIDI (again, except Ashtabula). Given the rural areas and longer travel times of the Ashtabula district, it is no surprise that restoration times might suffer by comparison to the more urban and suburban districts. (Note that CEI plans to establish a new service center in Claridon Township in southern Geauga County (in service date of 2009). This will improve crew response times in both the southern Geauga and Ashtabula counties. Overall, the district trends are consistent with the company-wide trends. They point to systematic recommendations (rather than "local" ones) to improve SAIFI (presented Section 5.0) and highlight the systematic (as opposed to "one time" or "local") improvements made over the past couple of years in outage response (CAIDI).

In terms of providing opportunities to further segment the analysis (and to better target reliability improvement initiatives), other than to reinforce the CAIDI-improvement actions already underway, there does not appear to be any further insights from a district-by-district review.

Voltage (4kV and 13.2kV)

The distribution voltages at CEI are 13.2kV and 4kV. The company also has an 11kV subtransmission system (96 percent ducted cable) used to serve distribution substations, large three-phase customer vaults, and a 120/208 V secondary network in downtown Cleveland. The 11kV circuits were designed with redundancy and are therefore rarely a source of significant number of customer interruptions. Of the over 1400 distribution circuits, about 400 are 13.2kV, and over 700 are 4kV, the rest being 11kV.

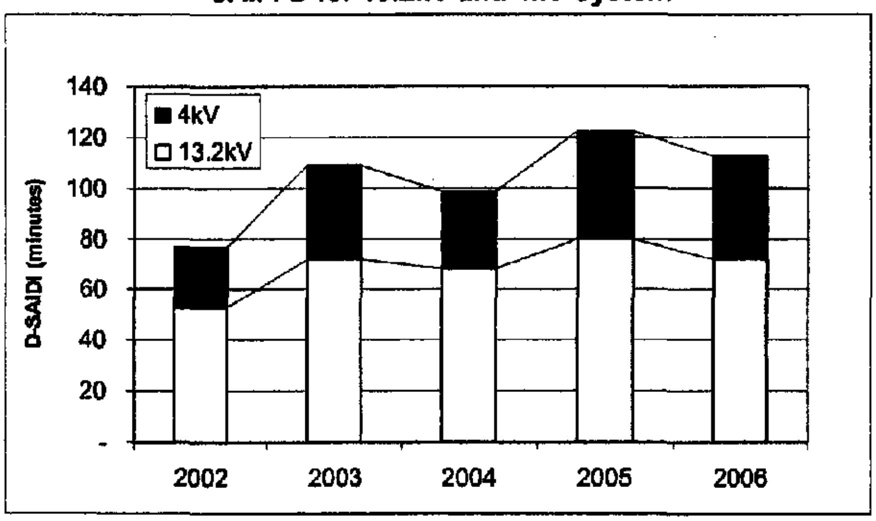
However, the number of customers served by the 13.2kV and 4kV is not proportionate to the number of circuits (over 60 percent of the customers are served from the 13.2kV). Consequently, the typical 4kV circuit is smaller than the typical 13.2kV circuit, not only in terms of serving fewer customers, but also in line length (a typical line length for a 4kV circuit is 5 miles vs. 21 miles for a 13.2kV circuit).

The 4kV circuits have 85 percent of their line miles as overhead, as most of the 4kV circuits were built before the era of Underground Residential Distribution (URD) where individual homes are served by directly buried secondary cables and served from pad-mount transformers connected by directly buried primary cable. While it is true that the 13.2kV has many miles of long overhead runs, it also has many miles of URD, making it on average only 54 percent overhead. The customer density for the average 4kV circuit is 76 customers per mile as compared to 57 for the 13kV. Given the average lengths of 4kV and 13.2kV, the average customer densities translate into average number of customers per circuit of 380 and 1200, respectively. Figures 3-16 and 3-17 present Distribution SAIDI by voltage class.

Figure 3-16
Distribution SAIDI by Voltage Class

Voltage	2002	2003	2004	2005	2006	2007
4kV	23.37	36.73	29.97	42.79	40.63	6.48
13.2kV	53.18	72.03	68.39	79.49	71.91	21.14
36kV	0.02	0.03	0.02	0.04	0.02	0.01
11kV	0.02	0.00	0.01	0.01	0.01	0.02
Total	76.60	108.80	98.39	122.40	112.57	27.65

Figure 3-17
SAIFI-D for 13.2kV and 4kV System



As with the Reliability by District review, our analysis above focused on SAIDI (the integration of SAIFI and CAIDI), recognizing that geography notwithstanding, the key strategies (as they relate to voltage) will focus around eliminating or mitigating customer interruptions. Figures 3-16 and 3-17 illustrate that when normalized for number of customers served, there are negligible differences in the performance of 4kV and 13.2kV circuits. The 13.2kV system accounts for 64 percent of the customer minutes (SAIDI) while serving 60 percent of the customers. An important insight is that though the 4kV system is older and in poorer material condition, the lower voltage and delta configuration makes it less prone for customers served by 4kV circuits to experience sustained outages due to circuit faults.

Therefore, the issue in differentiating among these voltages is less about reliability performance and more about relative opportunities to implement reliability improvement initiatives.

Worst Performing Circuits

A look at the Worst Performing Circuits provides another view in terms of establishing initiatives and perspectives around the goal of improving distribution system reliability. Figure 3-18 highlights the 25 worst performing 13.2kV circuits based on distribution customer minutes of interruption in 2006.

Figure 3-18
Worst Performing 13.2kV Circuits

Circuit	Substation	OH Miles	UG Miles	Line Miles	% OH	No. of Cust.	Cust /Mile	CMI	CI	Outages	CI/Out
0003	40024	13.71	36.83	50.54	27%	2,676	53	4,884,181	21,270	33	645
0003	40116	18.93	42.56	61.49	31%	2,091	34	1,480,339	4,552	37	123
0004	40116	24.39	31.39	55.78	44%	1,932	35	1,265,689	7,546	34	222
0002	40218	91.95	13.78	105.73	87%	1,560	15	1,220,792	3,216	70	46
0001	40127	8.54	3.44	11.98	71%	1,476	123	1,175,232	3,990	15	266
0003	40124	9.79	4.33	14.12	69%	2,065	146	1,022,236	4,478	18	249
0005	40031	13.46	14.71	28.17	48%	2,100	75	946,213	4,862	34	143
0003	40052	9.75	2.67	12.42	79%	2,739	221	895,445	6,273	23	273
0007	40053	4.74	18.63	23.37	20%	1,784	76	840,742	8,457	31	273
0001	40200	38.73	30.52	69.25	56%	1,509	22	778,141	3,946	32	123
0001	40190	41.61	30.08	71.68	58%	1,242	17	721,648	4,312	44	98
0006	40141	9.54	57.30	66.84	14%	2,754	41	716,978	5,748	37	165
0001	40162	19.63	12.48	32.11	61%	4,046	126	705,945	3,323	44	76
0006	40055	13.33	0.42	13.75	97%	1,573	114	690,201	2,072	15	138
0005	40129	6.11	5.96	12.07	51%	1,808	150	647,992	7,461	26	287
0004	40038	17.58	7.88	25.45	69%	2,176	85	624,549	5,018	39	129
0004	40075	15.45	1.91	17.36	89%	2,228	128	607,902	7,209	26	277
0007	40206	34.48	25.24	59.70	58%	1,176	20	605,491	3,274	41	80
0003	40186	24.19	37.93	62.12	39%	2,279	37	605,204	5,732	24	239
0006	40006	4.37	4.02	8.39	52%	317	38	590,383	4,146	18	230
0004	40162	14.64	8.12	22.77	64%	2,725	120	571,463	4,628	14	331
0002	40125	6.97	1.26	8.23	85%	1,371	167	569,750	3,365	6	561
0002	40103	19.28	13.50	32.78	59%	2,130	65	524,226	2,833	28	101
0004	40123	15.85	2.77	18.63	85%	3,153	169	508,910	2,910	28	104
0001	40180	33.39	57.31	90.71	37%	2,546	28	507,566	5,343	29	184

In examining these circuits, further insights can be gleaned for consideration in developing an overall system reliability improvement plan:

- **Circuit 40024-0003:** Average frequency of interruption is almost 7.9 and the average number of customer interruptions per outage is 645 (quite high). This is indicative of either a number of lockouts in 2006 and/or outages at the high end of the circuit (perhaps behind the second recloser). Closer investigation will reveal the best strategy (install additional reclosers or fuse unfused taps, and/or harden the backbone.
- **Circuit 40125-0002:** High customer interruptions per outage of 561. This circuit is only 8.2 miles long (7 miles of which is overhead), yet it contributed over 570 thousand customer minutes of interruption in 2006. A closer look at this circuit reveals that 527 thousand of those minutes were from one outage (December 1st). This lockout, a tree/non-preventable event involved all 1400 customers, requiring 6 hours to achieve full restoration. Thus, one event placed this circuit on the worst performing list. Though sectionalizing here may be warranted, there needs to be a balance between customer interruptions per outage and number of customer interruptions due to a number of lockouts or large outages, to more properly prioritize opportunities for sectionalizing.
- **Circuit 40124-0003:** Similar to circuit L002KI, this circuit is on the worst performing list as the result on one outage (a lockout of all 2100 customers on July 4th. Normally, dispatchers try to get a lockout handled in 30 minutes (or less). For 2100 customers to be out for almost 5 hours is indicative of severe understaffing (in terms of outage response) or an outage that just "slipped through the cracks." This circuit had another extended outage in 2006 involving 694 customers for 391 minutes. While not a full circuit lockout, it was a 65T fuse with almost 700 customers behind it.
- **Circuit 40190-0001:** Approximately 600 customers behind a recloser were out for almost 8 hours. The cause was a large tree that had fallen on the line as the initial crew tried to restore service by rerouting the feeder. While trying to switch around the faulted section of line, the crew found a broken disconnect switch which prevented them from achieving partial restoration of 500 of the customers until 6.7 hours into the outage.
- **Circuit 40218-0002:** Longest feeder on the list and most individual outages (72). Each outage is small with an overall average of 46 customers per outage. It is generally not productive to view these types of outages by feeder (rather geographically) as these are tap outages on very small taps. Each tap would probably require its own remediation strategy, and none are likely to be cost-effective. As such, these types of circuits should be treated as part of a worst device program, aimed at addressing repeat-offending devices; not as part of the solution for improving SAIFI and CAIDI.

Moving on to the 4kV circuits, Figure 3-19 below lists only the five worst circuits because anything more than that gets into contributions to CMI that are less than 500,000 customer minutes of interruption, which was the cutoff for the worst 13kV circuits. Again this demonstrates that the 4kV circuits are inherently smaller and not necessarily less reliable. Even on a per-customer basis, the 4kV system has a circuit SAIFI of .63, whereas it is .83 for the 13kV system.

- **Circuit 40205-0001:** One of the worst of the 4kV circuits, this circuit is atypical: a 40-mile 4kV circuit with only 600 customers. It is similar to the L002SP (Spruce) 13kV circuit in the Ashtabula district, in that it is a long feeder with a lot of small outages, with an average CI per outage of only 58.
- **Circuit 40109-0008:** The worst 4kV circuit, this circuit is of moderate length, 8 miles, with average customer density of 180 customers per mile, and has a very high average CI per outage of 420, suggesting many lockouts. In fact, examining the detailed records, there was only one lockout, and there was another case where on the same day, October 13, 774 customers were interrupted three different times due to a wire down in three different locations that were not found the first time. This again demonstrates how the 4kV circuits tend to self-sectionalize with wire-down failures. This also explains why CAIDI for the 4kV system in 2006 was higher than that for the 13kV system – restoration of wire down can take longer.
- **Circuit 40230-0003:** This is an underground circuit, with only two outages in all of 2006. As it turns out, they were two steps of the same outage, with the first step involving 378 customers for almost 19 hours and the second step involving 99 customers for almost a day and a half, as difficulties were found in the vaults where feeder ties were being made, and the restoration had to wait for the repairs. This is a situation where the only thing that should be done to prevent future problems is to inspect manholes and vaults regularly (which CEI does) and make repairs as needed.

Figure 3-19
Worst Performing 4kv Circuits

Circuit	Substation	OH Miles	UG Miles	Line Miles	% OH	Customers	Cust /Mile	CMI	CI	Outages	CI/Out
0008	40109	7.85	0.25	8.10	97%	1,461	180	1,241,988	4,196	10	420
0010	40150	4.40	0.24	4.64	95%	733	158	689,647	2,264	10	226
0003	40230	0.03	1.36	1.40	2%	398	285	609,921	477	2	239
0002	40119	2.03	1.68	3.71	55%	753	203	575,794	1,666	6	276
0001	40205	37.95	1.85	39.80	95%	607	15	556,373	808	14	58

To illustrate the impact of the worst performing circuits, consider that CEI only missed its SAIFI goal by 0.1 in 2006 and was .18 above its ultimate target of 1.0. With approximately 750,000 customers, 0.1 of SAIFI is 75,000 customer interruptions. The total number of customer interruptions on the worst 10 circuits was almost 70,000, and on the worst 20 it was almost 117,000 (and it would be higher if we had ranked the worst by CI instead of CMI). So, if CEI could have eliminated the outages on the worst ten or twelve circuits, or halved the outages on the worst twenty to twenty-five circuits, it would have achieved its goal and been halfway on the way to achieving its long-range target.

3.4.3 Causal Analysis

All utilities attempt to determine the cause of each outage and all utilities have problems doing so. While the rest of the outage information (customers interrupted, duration, circuit, and device) is relatively straightforward and subjected to only a few challenges, there are a number of inherent difficulties in establishing the outage cause. First, in many instances the cause is truly unknown, in that a responder arrives at the site of the blown fuse, patrols the line, finds no obvious problem, puts in a new fuse, and it holds. In such instances, assigning a cause tends to be a guess based on the weather at the time (wind, lightning) or the condition of the line (overgrown with vegetation).

Some utilities allow such informed guessing as a way to assign a cause, while others discourage such a practice. From our interviews and reviewing the data, it would appear that CEI used to allow these more speculative "guesses" and undertook an initiative to train employees on uniform coding to improve outage information quality.

Second, there are some logical problems with the cause codes that are typically used in practice. For example, if there are codes for weather (like wind, lightning, heat, and ice), then there may be some confusion with codes like equipment failure since, if lightning hits near a line, the failure of the lightning arrestor or shield to protect the line can be viewed as a kind of equipment failure. This is especially problematic with underground cable that fails in high heat. The potential confusion is obvious - should it be coded as caused by heat, overload, or equipment failure?

Third, in most cases the cause codes must be assigned before there has been time to truly investigate the outage. The priority, especially in a storm, is to restore service. It may and would take vital, extra time to search around for evidence of a dead squirrel (for example) or newly broken limbs that might have bounced off of the line and fallen to the ground, or for signs of nearby lightning flashes on trees that might have induced an over-voltage on the line, etc. True root-cause analysis may take some time, and potentially some specialized expertise, that is simply not available during the restoration process.

Nevertheless, within the limits of such problems, it is useful to explore what the cause codes reveal with respect to possible root cause. If one is willing to deal with the obvious coding problems, the analysis can often nevertheless reveal sensible patterns.

The data in Figure 3-20 show the trend in non-storm outages by the top three cause codes (Line Failure includes Lightning and Wind).

Figure 3-20
Key Causes Of Distribution SAIFI

Failure Cause	2002	2003	2004	2005	2006
Line Failure	0.12	0.22	0.21	0.25	0.26
Equipment Failure	0.10	0.10	0.11	0.14	0.24
Trees/Non-Preventable	0.09	0.09	0.11	0.11	0.13
TOTAL	**0.31**	**0.31**	**0.43**	**0.50**	**0.63**
PCNT D-SAIFI	**83%**	**87%**	**87%**	**84%**	**89%**

The outages from these three cause codes made up approximately 89 percent of distribution SAIFI in 2006, suggesting a number of specific initiatives (refer to Sections 5.0 and 6.0) to sharpen our focus as we harden the distribution feeder backbone (i.e. enhanced tree trimming, lightning protection, sectionalizing, repairing loose cross arms, pins and ties, and upgrading UG cable, etc.).

Line Failure

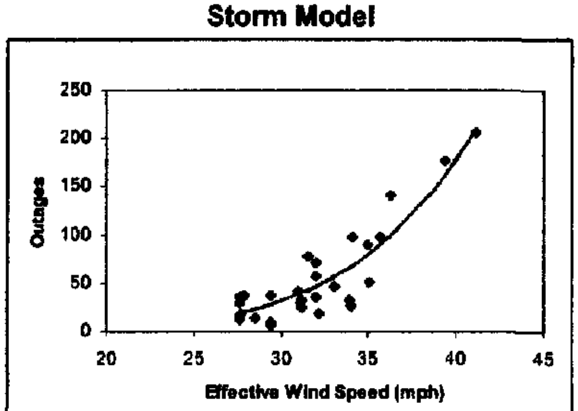
In further analyzing line failures, we have necessarily included wind and lightning (accounting for the change in coding between 2003 and 2006). Figure 3-21 below illustrates that for both voltages the trends are similar: Significant progress was made from 2003 and 2005 in reducing the number and percentage of lockouts resulting from line failure related customer interruptions followed by a return to 2003 levels in 2006. This dramatic reversal reinforces the need to harden the feeder backbone. It also suggests that some operational changes (e.g. protection schemes) may have been implemented during this period (requires further investigation). Note that no protection scheme changes were made to the 4kV system. Instantaneous trips were re-enabled on 13 kV circuits resulting in increased momentary interruptions, but this action would not have contributed to an increase in the number of lockouts.

Figure 3-21
Line Failure Customer Interruptions Due To Lockouts

Voltage	Measure	2003	2004	2005	2006
13.2kV	Number of Customer Interruptions	76,239	107,242	121,906	138,446
	Lockouts	26,431	29,234	18,613	45,296
	Percent	35%	27%	15%	33%
4kV	Number of Customer Interruptions	45,834	46,783	65,728	55,136
	Lockouts	25,689	16,407	13,981	22,044
	Percent	56%	35%	21%	40%

Though no longer reported separately by CEI as a cause, a main contributor to the Line Failures and Trees/Non-Preventable (see below) related outages is wind. Figure 3-22 is an analysis of all of the days in 2006 when the sustained wind speed at Cleveland Hopkins Airport were 30 MPH or greater and it reveals that the number of outages increases exponentially as effective wind speed reaches (and exceeds) 35 MPH. In fact, between 30 and 35 MPH CEI can anticipate experiencing 25-100 outages and after 35 MPH range between 100-200 outages per day.

Figure 3-22
Storm Model



Similarly, Lightning (also reported as part of the Line Failure Cause Code) is a major cause of outages (Line Failure and Trees/Non-Preventable). There were at least 6 days in 2006 of 50 outages of more, where lightning was reported in the area (July 10^{th}, July 27^{th}-28^{th}, June 21^{st}, July 20^{th} and October 17^{th}). As will be discussed in Section 5.0, effective lightning mitigation goes beyond adding arrestors. CEI should employ advanced root cause analysis to check for grounding, poor BIL in construction, and lack of natural cover. Advanced tools such as the FALLS system, currently owned by FirstEnergy, need to be used at CEI.

Equipment Failure

Figure 3-23 below points to an increase in the number of equipment failure related customer interruptions (and proportionate increase in lockouts) in the 13.2kV system and similar increases in the 4kV system with noted improvement in lockouts (as a percent of customer interruptions). Therefore, the focus in this area should be focused more on reducing the number of interruptions and less on operational issues.

Figure 3-23
Equipment Failure Customer Interruptions Due To Lockouts

Voltage	Measure	2003	2004	2005	2006
13.2kV	Number of Customer Interruptions	39,568	58,894	100,102	88,574
	Lockouts	11,122	14,036	30,938	23,397
	Percent	28%	24%	31%	26%
4kV	Number of Customer Interruptions	14,100	24,430	38,366	51,475
	Lockouts	6,997	7,495	9,263	13,067
	Percent	50%	31%	24%	25%

Outside of equipment aging related issues, a major contributor to equipment failure is excessive heat. Whenever heat is near the 90's for three days (or more) in a row, particularly with high humidity, the impact is exponential. In 2006 CEI experienced a heat storm from July 30^{th} to August 2^{nd}, with the high temperature at 92 degrees for all 4 days. During this time period, CEI experienced 80 to 142 outages a day. On May 30^{th}-31^{st}, the temperature reached the high-80s and CEI experienced 87 outages on the 30^{th} and 142 on the 31^{st} (many of the ones on the 31^{st} could have been due to lightning).

In terms of preventive action, proper system planning at the feeder level to determine those places where the cable is likely to be heavily loaded in case of severe heat is a necessary first step. Upgrading of that cable and/or shifting of the load will allow the cable to withstand the heat (resulting from ambient heat and load-induced heat from air conditioning). URD cable failures are also related to heat and should be addressed via a systematic replacement program (3 failures). However, generally URD cable serves small groups of customers and will not have a major impact on SAIFI or CAIDI.

Trees/Non-Preventable

The trends addressed in Equipment Failure apply as well to the statistics around Trees/Non-Preventable. For both voltages the number of tree/non-preventable related customer interruptions has increased since 2003 with the number of lockouts (as a percent of customer interruptions) remaining unacceptably steady for the 13.2kV system at 47-49 percent, and improving rather dramatically for the 4kV system (24 percent in 2006).

Figure 3-24
Trees/Non-Preventable Customer Interruptions Due To Lockouts

Voltage	Measure	2003	2004	2005	2006
13.2kV	Number of Customer Interruptions	37,296	62,156	53,682	70,293
	Lockouts	17,548	29,379	19,448	34,553
	Percent	47%	47%	36%	49%
4kV	Number of Customer Interruptions	14,070	19,024	28,958	27,043
	Lockouts	6,956	5,641	10,761	6,611
	Percent	49%	30%	37%	24%

3.4.4 Outage Restoration

CEI has clearly made significant strides in improving its overall performance in the area of restoration (reducing customer minutes). Section 6.0 will highlight the initiatives already in place to continue this trend. This portion of the analysis will address the key variables that affect outage duration and their impact on CEI's performance to date, namely:

- Number of Outages
- Timing of Outages

Number of Outages

One of the key factors influencing CEI's CAIDI performance is the number of outages experienced per day. On days of heavier volume, the regular number of troubleshooters and line crews are spread more thinly and jobs are delayed. The data in Figure 3-25 below illustrates this point by calculating CAIDI for the 35 days that had the highest number of outages. Note that this table was not constructed by choosing the days with the worst CAIDI (although it results in a similar selection). Rather, it was constructed by choosing the days with the most outages per day and then examining the resultant CAIDI for each day. The excludable major storm days in 2006 (October 28-30, and January 14-15) are not factored into this analysis.

Figure 3-25
Highest Number of Outages Per Day (Top 35)

Date	Worst Hours	Day	Outages	CI	CI/Out	CMI	CAIDI
12-1	Noon-5PM	Fri	219	37,852	173	10,715,451	283
5-31	1-5PM	Wed	194	24,754	128	3,773,124	152
2-17	5-7AM	Fri	184	15,606	85	3,476,518	223
6-19	2-3PM	Mon	142	13,522	95	2,268,028	168
7-27	Noon-4PM	Thu	139	5,705	41	1,141,891	200
7-10	8-11AM	Mon	124	17,256	139	1,541,834	89
7-31	3-8PM	Mon	122	24,590	173	8,278,037	337
8-1	5-8PM	Tue	121	32,438	268	5,595,333	172

6-22	4PM	Thu	103	20,423	198	3,036,050	149
3-10	5-8AM	Fri	96	4,678	49	666,942	143
7-30	5-7PM	Sun	95	12,133	128	1,528,829	126
7-17	5PM	Mon	94	18,044	192	3,114,536	173
7-28	5-7AM	Fri	93	9,098	98	1,742,890	192
8-2	2-4PM	Wed	81	5,567	69	573,170	103
7-4	2-4AM	Tue	78	9,996	128	2,479,044	248
5-30	4PM,8PM	Tue	77	12,013	156	1,015,285	85
6-21	2-4AM	Wed	75	12,733	170	1,773,196	139
10-13	Noon-4PM	Fri	71	6,995	99	1,703,091	243
7-14	1PM	Fri	66	12,532	190	1,428,826	114
10-17	5PM	Tue	64	6,357	99	743,894	117
7-16	6PM	Sun	63	6,766	107	1,184,677	175
7-20	Noon-2PM	Thu	62	10,314	166	981,893	95
6-28	7-8PM	Wed	56	9,977	178	1,383,634	139
3-13	8-9AM,7PM	Mon	54	6,210	115	759,925	122
10-11	6AM-7PM	Wed	52	9,627	185	1,125,378	117
7-12	3AM-11PM	Wed	51	4,864	95	526,042	108
9-9	Midnite-9AM	Sat	49	968	20	163,038	168
8-3	10AM-4PM	Thu	48	2,096	44	464,862	222
7-2	8AM-1PM	Sun	48	8,545	178	619,412	72
9-13	10AM-1PM	Wed	47	6,551	139	554,083	85
1-18	6-9AM	Wed	47	10,260	218	721,174	70
7-22	9AM	Sat	45	2,901	64	533,501	184
4-3	3-6PM	Mon	45	988	22	113,434	115
12-2	Midnite-9AM	Sat	44	1,414	32	381,039	269
6-18	2-7PM	Sun	44	1,667	38	284,307	171
Total			2,993	385,440	129	66,392,368	172
% of total for all outages			36%	44%		59%	

As the bottom line of Figure 3-25 shows, these specific 35 days were less than 10 percent of the year and they account for 36 percent of the outages for 2006, 44 percent of the total customer interruptions (the numerator of SAIFI and the denominator of CAIDI) and 59 percent of the total customer minutes of interruption (the numerator of SAIDI and CAIDI). Total CAIDI for this group of outages is 172 minutes. The CAIDI for the rest of the outages is 94 minutes.

The days of highest volume present the greatest challenge to achieving the CAIDI targets, but this analysis extends beyond the obvious, quantifying the extent to which outages drove CAIDI for CEI in 2006, and thereby facilitating quantification of the benefits of changes that would improve CAIDI on the days of highest volume. Figure 3-26 below reveals the underlying pattern in the data by grouping the results in 5-day groupings.

Figure 3-26
Highest Numbers of Outages per 5 Day Groupings

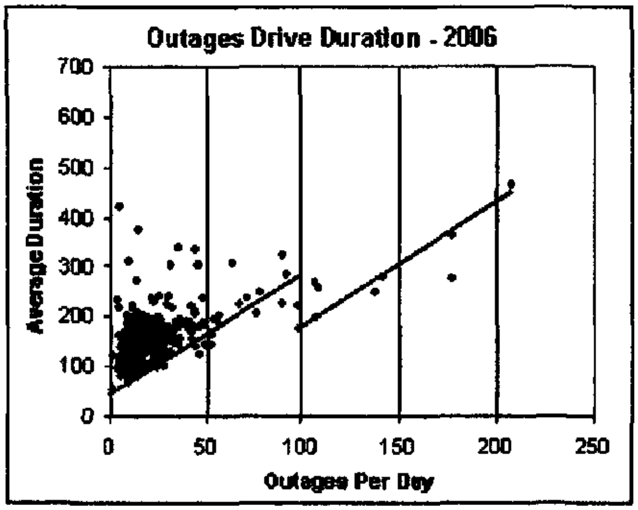
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1-5	878	176	97,439	21,375,012	219
6-10	566	113	99,385	19,118,196	192
11-15	441	88	54,838	9,438,469	172
16-20	353	71	50,630	6,664,292	132
21-25	287	57	42,894	5,435,507	127
26-30	243	49	23,024	2,327,437	101
31-35	225	45	17,230	2,033,455	118

Clearly, as outages per day increased from 45 to almost 176, CAIDI increased from around 101 to over 219 (the fact that CAIDI for the 31-35 grouping is higher than that for the 26-30 grouping is an artifact due to the timing of outages). This suggests that for each additional outage per day, approximately one minute is added to CAIDI (e.g., increasing from 50 to 75 outages per day might increase CAIDI from 101 minutes to 126 minutes; and increasing from 75 to 175 outages per day might increase CAIDI from 126 minutes to 226 minutes)

This relationship between the number of outages and increases in CAIDI held despite the commendable effort made by CEI to improve its storm response (e.g. holding over the day shift crews, using an alternate shift-11AM to 7PM for some crews to better cover late-afternoon thunderstorms, and exhibiting flexibility in transferring crews across line-shop boundaries).

To further drive home the point (and illustrate the effects of pre-mobilization/pre-positioning of resources), Figure 3-27 below graphically displays the average outage duration (minutes) against the number of outages per day. The fairly consistent trend from 0 to 100 outages per day reflects "business as normal." The obvious "step down" in average duration at 100 outages per day reflects preemptive actions on the part of CEI (based on a "gut feel" that pre-mobilization/positioning is warranted).

Figure 3-27
Number of Outages Drive Duration (2006)



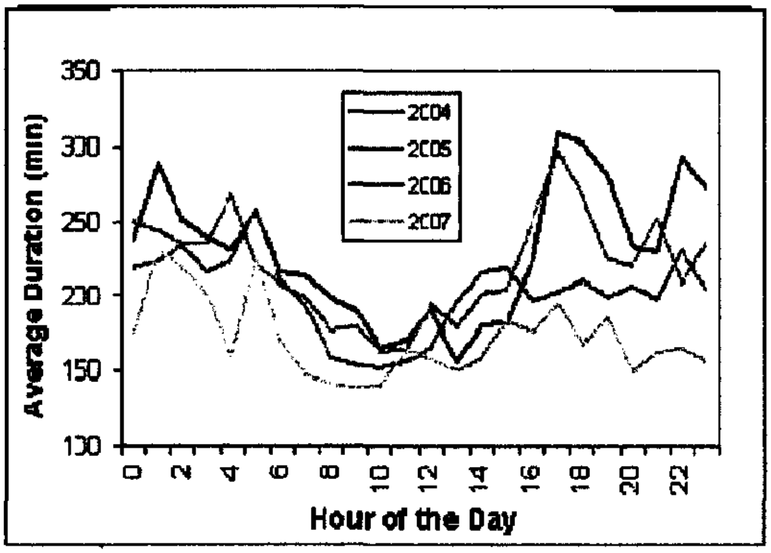
Timing of Outages

A closer look at the details of the Figure 3-23 reveals how the timing of the outages affected CEI's response as well. Some of the highest customer minutes within a given level of outages are obtained when a storm hits hardest at hours other than the weekday day-shift. (Note that the highest number of outages per day occurred on December 1st, a Friday afternoon). To further illustrate this point, the sixth-worst day, July 10, had 124 outages but a CAIDI of only 89, as the worst of the storm occurred at 'prime time' for the day shift: 8-11AM on a Monday. Conversely, the next worst day in terms of outage volume, July 31, had virtually the same number of outages (122), but happened between 3 and 8PM (also a Monday), and CAIDI for that day was the highest of any day in 2006: 337 minutes. There were likely other factors that contributed to such a high CAIDI, but note that the next worst day, August 1st, had a similar number of outages (121), also occurring mainly in the evening hours, and a CAIDI of 172 minutes (the average for the whole table of the 35 worst days).

One of the worst CAIDI performances (248 minutes) occurred on July 4th, when most of the outages occurred in the early morning hours (2-4AM). Another of the worst CAIDI performances (243 minutes) occurred on October 13, a Friday, with most of the outages hitting between noon and 4PM (in fact, a third of the day's 71 outages occurred after 3PM). Again, this supports the notion that outage response on Friday afternoon (and early Saturday morning) is somewhat worse than at other times. On Saturday, December 2nd, the day after CEI experienced the highest number of outages (219), 7 outages occurred between midnight and 1AM and another 11 occurred before 5AM. The resulting CAIDI for December 2nd was 269 minutes (though only 44 outages were experienced).

Figure 3-28 illustrates this point, and again shows how CEI's initiatives since 2006 have lessened the impact.

Figure 3-28
Outage Duration by Hour of Day



There was also some evidence that when the outages came almost all at once, CAIDI was higher. As one might expect, outages spread evenly throughout the day tend to be handled more easily.

All of this reinforces a recommendation that CEI improve its ability to forecast days of heavy volume and proactively mobilize to meet the challenges. Additionally, any success in reducing customer interruptions will likely reduce the number of days in which an extraordinary number of outages causes restoration delays.

4.0 Reliability Improvement Framework

4.1 Purpose, Scope, and Approach

The reliability of an electric system can be viewed as the composition of two interrelated elements: adequacy and security of a customer's power supply. Adequacy refers to the system's capacity to deliver energy to meet peak demand conditions. Security refers to the ability of the system to withstand contingencies (or sudden changes) on a daily, hourly, or even instantaneous basis, such as the loss of a key system asset (a transformer, a line, etc.), a source of supply, or a point of demand.

Rule 4901:1-10-10 of the Ohio Administrative Code requires that each electric distribution utility ("EDU") annually report its system reliability performance against a set of system reliability targets. The Cleveland Electric Illuminating Company ("CEI" or "Company") has not met its annual customer average interruption duration index ("CAIDI") target (95 minutes) since this rule became effective in 1999. Additionally, CEI has not met its annual system average interruption frequency index ("SAIFI") target (1 interruption per customer served) since 2002.

During 2005, CEI management and Public Utilities Commission of Ohio ("PUCO") Staff discussed a set of interim targets and CEI made a commitment that if the Company missed any of the interim targets, CEI would hire an independent consultant to provide PUCO Staff with an independent assessment of CEI's infrastructure and operational practices. The assessment would be designed and implemented to also make recommendations to improve reliability in the CEI service territory by identifying steps that may be taken to make meaningful improvements in CEI's CAIDI and SAIFI performance.

The purpose of this section of the report is to outline the reliability improvement framework we envision for the Company and describe how we will transform our analyses of the electric system (outlined in Sections 2 and 3 of this report) into specific recommendations (presented in Sections 5 through 8).

Informed stakeholders understand that the overall reliability of an electric distribution system as measured by CAIDI and SAIFI is the result of a very complex interaction of technical, managerial, and network conditions and decisions; they include such factors as:

- How the system is designed (its configuration, capacity, technology, etc.),
- The age and condition of the system's components,
- How the system is operated (both electrically and how the work force is coordinated),
- The local demand and weather conditions, and
- How the system is maintained.

This complexity demands that any assessment should be structured in a way sufficient to organize the analyses and simplify the presentation of its recommendations. For the purpose of this assessment, we will present the analyses and recommendations, organized into two major categories:

- Service Interruption (Section 5.0) – here we will define industry leading practices, and CEI's efforts aimed at reducing service interruptions (often referred to as outages) and thereby reducing (i.e. improving) SAIFI. In so doing, the focus will include recommendations to reach the target SAIFI goals by 2009 and to satisfy the imperative of long-term sustainability (i.e. to meet the SAIFI targets consistently over a 10-year period).

- Service Restoration (Section 6.0) – here we will identify approaches and CEI's recent actions aimed at reducing the duration of outages (measured in customer minutes of interruptions-CMIs) and thereby reducing (or improving) CAIDI.

Recognizing that resources (financial and human) are also required to execute this Reliability Improvement Framework, the focus of this report will then shift to assessing the organization structure and staffing levels within CEI (Section 7.0) and the investment funding levels (Section 8.0) necessary to execute the plan.

4.1.1 Reliability Improvement Framework

We observe that utility managers take specific actions (business or technical changes, new practices, etc.) in how they operate, maintain, and design/configure the electric distribution system to continuously improve reliability. More specifically, management will implement actions with an eye toward reducing interruptions (i.e. improving SAIFI) or reducing interruption duration (i.e. improving CAIDI).

Furthermore, some actions are designed to mitigate the impact of events (i.e. reduce the scope) and others will eliminate events altogether. Utility managers should (and CEI does) build up a reliability improvement program using the elements of this framework (either explicitly or implicitly). From this perspective, we see that potential electric system Reliability Improvement Initiatives fall into general categories as presented in Figure 4-1 below:

Figure 4-1
Illustrative Reliability Improvement Initiatives

Scope	**Interruptions** (SAIFI Improvement)		**Duration** (CAIDI Improvement)
	Mitigation Strategies	***Elimination*** Strategies	***Mitigation*** Strategies
Operations	Adaptive Relaying Improved Fuse Coordination / Managed Protection Schemes	Switching Errors	"Cut and run" for OVHD "Split it and hit it" for UNDG Sufficient Staffing; Scheduling Storm Scheduling Dispatching Switching Plans

Scope	Interruptions (SAIFI Improvement)		Duration (CAIDI Improvement)
	Mitigation Strategies	***Elimination*** Strategies	***Mitigation*** Strategies
Maintenance	Preventive Maintenance on Key System Components (e.g. Reclosers, Sectionalizers)	Tree Trimming Pole / Line inspection VLF Cable Inspections	Monitor and manage assets in abnormal condition
System Design / Configuration / Security	Reclosers Sectionalizers System Reconfiguration	Lightning Protection Animal Guarding Replacement of failing component (Poles, UG, etc.) System redundancy in design	Distribution Automation Reclosers / fault indicators SCADA System network ties / design redundancy

Figure 4-1 (above) by no means represents *all* of the options that are available to CEI; rather, it is intended to be an illustrative framework to organize the subsequent analyses and recommendations presented in sections that constitute the remainder of this report. Graphically, our analysis translates our assessment of reliability (interruptions and duration) outlined in Section 3 into specific recommendations for operations, maintenance, and system design / configuration options (presented in the following sections).

Moreover, we caution the reader to understand that the structure provided above is designed to provide a framework for developing our analyses and to present a cogent approach to communicating specific recommendations. However, as with all simplifying structures, such a structure can be misleading with regard to *second order* effects that must also be considered. Well known and documented examples of these second order effects related to electric system reliability include, for example:

- Eliminating interruptions by sectionalizing and adding reclosers will often cause the average outage duration as measured by CAIDI to rise, because the short duration outages that are eliminated will drive up the overall average duration, or
- Reducing overall interruptions may improve performance under storm conditions and thereby reduce the number of events that would have fallen into the *storm excludable* category. As such, overall reliability (storm and non-storm) may be improved while the *measured* "non-storm" performance CAIDI or SAIFI may appear (as measured) degraded.

With this in mind, we will take every opportunity throughout this report to document these second order effects.

Lastly, some reliability-related elements (e.g. customers experiencing multiple interruptions (CEMI)) are closely linked with customer satisfaction objectives. However, they generally do not have a material impact on CAIDI and SAIFI and are beyond the scope of this assessment.

Our overall assessment approach is presented in the following subsection.

4.2 Standard Assessment Approach

Our summary of our findings, conclusions, and recommendations is presented in the following sections of this report in a standardized format where in each area of investigation we present the following information:

- Scope and Context
- *Current State Assessment*
- Recommendations

Each of these topics is described in the following subsections.

4.2.1 Scope and Context

This introduction to each topical area will explain:

- Our definition of the scope of the topical area in question. Our objective is to explain the nature of our analysis, and
- Our basic expectations for how a leading utility would evaluate or address the topical area in question. We hesitate to use the term "best practice" in this context because different utilities have various practices for major activities. We prefer to use "leading practices" to connote better but not necessarily a definitive definition of top performance.

4.2.2 Current State Assessment

In this section we will summarize our assessment of CEI's current performance in each area of investigation. In this section we will explain:

- Our observations or "findings" as revealed by the interviews and review of CEI's data. We will not expressly define "findings" in a strict sense, as the term often connotes mixed or "negative" interpretations when in fact we are seeking to identify both areas of good performance and opportunities for improvement.
- We will also seek to summarize any analysis necessary to substantiate the basis for a recommendation.

4.2.3 Recommendations

In each section we will summarize our key recommendations in a standardized table and present them in the following way:

Figure 4-2
Typical Recommendation Table for Sections 5 Through 8

ID	Recommendation
O-1	A brief description of the recommendation will be placed in this box.

5.0 Service Interruption Assessment

5.1 Purpose, Scope, and Approach

The purpose of this section is to translate the information developed and analyzed in our Electric Infrastructure Review (outlined in Section 2.0) and our Outage History and Cause Analysis (outlined in Section 3.0) and integrate it with the results of our operational interviews into specific actions and recommendations aimed at improving CEI's performance with respect to service interruptions (also referred to as outages) and thereby reducing (improving) SAIFI.

In so doing, our focus will be on both short term recommendations to reach the target SAIFI goals by 2009 and long term approaches to address the objective of sustainability (e.g. to meet the SAIFI targets consistently over a 10-year period). At the highest level these recommendations fall into three categories:

- Protect the Backbone (Hardening and Sectionalizing)
- Non-Feeder Backbone Initiatives (Worst Performing Circuits and Devices, Worst Performing Devices, Underground Cable Replacement and ESSS Inspections and Repairs)
- Long-term Approaches (System Capacity and Overload, and Refurbishment and Replacement of Aging Infrastructure)

5.2 Protect the Backbone

5.2.1 Scope and Context

The analysis in Section 3.0 verified that the most immediate and cost-effective strategy for improving CEI's distribution circuit reliability is to protect the feeder backbone. The backbone, also informally referred to as the mainline, main gut, or feeder (which is sometimes also synonymous with the whole circuit), is the normally three-phase part of the circuit that runs unfused from the substation to the normally open ties to other circuits or to the physical end of the circuit (i.e. at a geographical or territory boundary, etc.). The backbone may include reclosers, but not fused taps.

Another way to describe it is that the backbone is every part of the circuit that is <u>not</u> behind (i.e. electrically downstream of) a fuse.

Protecting the backbone is typically done in two ways:

- Hardening: Focuses on methods of making the infrastructure less susceptible to service interruptions, and
- Sectionalizing: Involves the installation of additional reclosers in targeted protection zones as well as fusing unfused taps.

Hardening is aimed at eliminating service interruptions (measured as customer interruptions) and sectionalizing serves to mitigate the impact of service interruptions by minimizing the number of customers impacted by an outage.

5.2.2 Hardening the Backbone

The following discussion will center on the leading industry practices around the key methods for eliminating service interruptions (outages); namely, enhanced vegetation management, inspection, repair and renewal of overhead lines, lightning protection, and animal mitigation.

Enhanced Vegetation Management

We observe that the vegetation management practices of most utilities (especially those with reliability issues) evolve through three stages:

- Stage 1 – Get on cycle: Most utilities find it easy to defer tree trimming activities and related expenditures whenever revenue shortfalls or expense overruns produce earnings pressure. Yet tree-trimming specifications usually are designed to achieve a clearance that is likely to be effective in avoiding contact for a fixed number of years (such as a four-year cycle). Some fast-growth species may require more trimming or mid-cycle "hot spotting," but the majority of the circuit should be relatively trouble-free from normal growth-caused contact for the given cycle.

  When funds are cut, trimming is deferred past the planned trimming interval (cycle) and trouble begins. For the circuits currently experiencing trouble, future trimming will need to not only be restored to the cycle amount, but also increased to "catch up" what was missed. This, in turn, causes a built-in unevenness to future trimming schedules as well as the inefficiency of varying crews accordingly.

- Stage 2 – Optimize the cycle: Once a utility achieves consistent performance on a regular trimming cycle, it may try to step up to the next level of vegetation management to optimize the cycle and processes. This includes allowing the cycle to vary by circuit depending on factors that would cause one circuit to need a longer or shorter cycle.

  This is not the same as deferring trimming whenever the company needs more earnings. Instead, it is a carefully planned approach to doing a fixed amount of trimming on the system each year. This is similar to an approach that would target the worst-performing circuits first, but it combines it with the discipline of recognizing that there is a certain interval of time – different for different circuits – at which the circuit must be re-addressed.

  Typical optimizations include doing the backbone on a different cycle than the laterals because of the larger impact of backbone outages. Transmission trimming must be more aggressive than distribution trimming to the point where, for most utilities, transmission trimming means mowing and spraying a wide right-of-way under the towers, and side trimming plus danger-tree removal. Other adjustments may include trimming lower voltages on a longer cycle and trimming urban areas, where easements may be narrower and clearances harder to obtain, on a shorter cycle. Included in this phase may be contracting improvements that typically include a move from time and materials (T&M) to unit price (or at least managing T&M as if it were unit-priced). Other enhancements may include smart use of herbicides to reduce stem growth and better work with communities to integrate utility trimming with urban forest aesthetics.

- Stage 3 – Target broken limb/fallen-tree outages: Once a utility's growth-caused (or contact-caused) outages are less than 50% of its vegetation-caused outages, active managers typically begin asking questions such as, "We just trimmed those circuits; why are they still having outages (especially in storms)?"

  Even though most tree-trimming specifications will call for removal of "danger" trees (i.e. those that are dead and likely to hit the line), in practice the costs of such work is often prohibitively high if done extensively. For example, if regular trimming costs $2000 to $4000 per mile, heavy removal of overhang above the normal amount or removal of trees or branches that are not dead but are structurally weak could easily cost $10,000 per mile. The key to realizing the cost-effective benefits of taking the next step is to carefully target the places where such work is done based upon impact on the system.

CEI, along with the rest of FirstEnergy, has clearly reached Stage 2 (as characterized above) in its development, as evidenced by the following points:

- CEI's four-year tree trimming cycle has been effective in reducing customer interruptions attributable to the category "tree-preventable", as evidenced by a reduction of contribution to SAIFI of .01 in 2003 to .001 in 2006.
- In 2006, 99 percent of tree-caused customer interruptions were non-preventable (only 1 percent was attributable to the contact-caused outages that normal tree-trimming addresses, as opposed to a broken limb and fallen tree cause).
- The program has already begun to take advantage of Stage 2 targeting of the first zone and backbone of a circuit in optimizing its cycle-based work.

The next step for CEI's tree trimming program is to begin to attack what is called the 'non-preventable' tree-caused outages. We understand the use of this term and find it common in the industry, but we prefer to call them "broken limb/fallen tree outages" to highlight that they are actually preventable but with a different kind of program.

Such a program is not focused on merely avoiding grow-in contact-caused outages (although that effort must continue) but also on avoiding the most customer-impacting cases of broken limb and fallen tree by doing more to remove overhanging limbs and structurally weak trees.

Such a program cannot normally be cost-effectively applied to the entire system. Indeed, the kind of clearances required would often be deemed excessive on the taps that typically serve two-lane suburban streets. However, feeder backbones typically are adjacent to major thoroughfares and commercial areas where enhanced removal is often more acceptable, particularly on the second or third time as the tree begins to take on the appearance of one that has 'grown away from the lines'.

Figure 5-1
Example Clearance

Figure 5-1 is an example of such an appearance on a four-lane road in another service territory. While it shows a virtual 'ground-to-sky' clearance, in other examples in which the construction is not vertical and/or the tree is of a different shape, it may suffice to simply remove any branches that, if they broke, could 'hinge' from the break down in to the line. Utilities would particularly target limbs that have developed a large amount of foliage on the end of a long branch and which is hanging almost perpendicular to the tree. This would be an example of the type of 'structural weaknesses which an experienced tree crew should recognize as a target for removal in those cases in which limb failure could interrupt many customers, e.g., a feeder backbone.

CEI should optimize and enhance its tree-trimming program (and already has started with its "Danger/Priority Tree Program") to target potential outages to the backbone caused by broken limb/fallen tree situations that can be identified in advance as cases of 'structural weakness'. Such a program should begin with, and possibly be limited to, those feeders that have exhibited the worst experience with tree-caused backbone outages.

Lightning Protection

CEI's service territory is not particularly lightning-prone by national standards. Such an assessment may be contrary to those who live and work in the region, but various studies have shown that the most lightning-prone area of the United States tends to be in the far southeast, as evidenced by Figure 5-2, the map of the continental United States displaying isokeraunic contours, i.e., lines of equal lightning activity per year.

Clearly, Ohio is at level 40-50 compared to level of 80-100 in Florida, the Georgia Coast, and the Eastern Gulf of Mexico. Nevertheless, Ohio does see more lightning than, say, the West Coast and even to some extent New England.

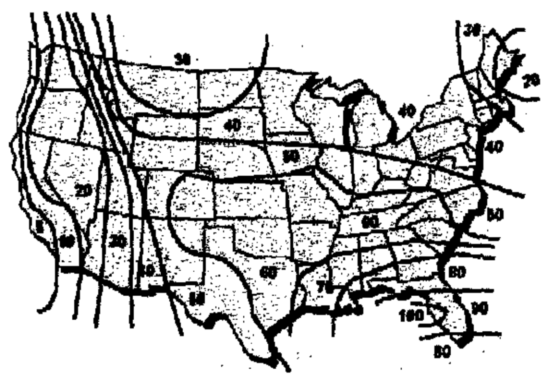


Figure 5-2
U. S. Lightning Patterns

As a source of customer interruptions at CEI, lightning has consistently ranked in the top four or five causes, after tree-non-preventable, equipment failure, and line failure. In 2006, changes in the instructions on coding outage causes have greatly reduced the number of customer interruptions from coded as lightning, but the consequent increase in line failure and unknown suggests that there are probably still many lightning outages and CEI is simply following the practice of many companies in not declaring an outage as lightning-caused unless the evidence is undeniable. This means that many outages that are quite likely to have been caused by lightning are not so coded. Even before that change, many outages labeled unknown (or most recently "line failures") may be due to lightning and utilities recognize that many 'blue sky' overhead line equipment failures may be the result of fuse fatigue caused by a previous lightning flashover. Animal-caused outages are often higher in number, but they often affect only distribution line transformers and thus affect fewer customers than the blown line fuse or locked out circuit breaker that often is the result of a lightning strike. In short, lightning protection, if it could be effective, has the potential to significantly reduce CEI's customer interruptions.

The caveat 'if it could be effective' is a significant qualifier. Whereas trees do not exhibit a kind of intelligence about finding a way to fault (many anecdotes can be related about twigs arcing but not faulting, limbs on lines that don't fault because they dried out first, and, at lower voltages, limbs that have grown around the wire), lightning has a way of finding the weakest link in the chain in its search for a path to ground.

Thus, it is possible to find instances of where companies have made significant expenditures with an intention to reduce lightning-caused outages by, say, 75 percent, only to find that the impact was 25 percent or less due to flaws in the lightning protection scheme.

The industry is full of lightning lore, some of it backed by hard evidence. The concept of a 'scout arrester', for example, is based on the idea that when lightning strikes at or near a line (lightning is capable of inducing a voltage surge even when it does not directly hit a line), the over-voltage condition travels down the line 'looking' for a path to ground (which, in an AC system, can include another conductor). It may travel many spans in a straight line but when it reaches a bend or a double dead-end; it is 'reflected' off of the insulators at that point and may achieve a higher over-voltage condition. A lightning arrester placed at the point of reflection may not be sufficient, and a 'scout' arrester placed one or two spans before the reflection point, may prove to be effective.

Once the task is undertaken to reduce lightning-caused outages, it requires an intensive effort at root cause analysis. It also requires consideration of a broad range of remedies. While deploying additional lightning arresters is the standard remedy and usually a good one, there are many other considerations. Adequate grounding is important, and can be difficult in rock or sand. Certain types of construction, some adopted in the late 1960's and early 1970's for aesthetic reasons may turn out to have poor lightning protection. Many areas may benefit from natural cover while others leave the poles as lightning rods standing in an open field. The industry is full of examples of especially lightning-prone situations that require special remediation.

Lessons like this tend to be learned by field personnel who encounter situations in which lightning problems persist, despite their best efforts to protect the system. This actually provides a kind of laboratory to try different methods because the failure is so consistent until the right solution is found.

Besides such insights to aid the reliability engineer, the industry has developed sophisticated tools to analyze lightning-caused outages. The National Lightning Detection Network (NLDN) is an extensive system of radio sensors that is used to triangulate on the source of radio interference caused by lightning, allowing identification of an ellipsoid of probable location of the strike. A software program called FALLS (Fault Analysis and Lightning Location System) which is currently owned by Vaisala, Inc., allows the user to analyze lightning strike data and superimpose it on a utilities own facility and outage data to determine the likely location of strikes.

The effectiveness of the program is very sensitive to the availability or exact timing of the outage and also to facilities that run from a single point to another, such that an ellipse of possible location crosses the line at only one point or small area. makes it ideal for confirming the location of transmission line outages, which typically have SCADA at both ends and run point-to-point, but makes it less useful for distribution feeder outages, because the time of the outage is often known imprecisely (depending on when the first customer calls) and the configuration of the feeder is often more tree-like or grid-like than point-to-point. Also, the sheer number of distribution outages can effectively preclude taking the time to analyze each one (FALLS analysis is a rather labor-intensive process).

An exception, however, is the feeder backbone, which is ideal in three ways. Like a transmission circuit, it:

- Is typically point-to-point or close to it,
- Usually (at CEI) has SCADA that can tell exactly when the outage occurred, for exact match to only one or two lightning strikes in the area at that exact time, and
- Interrupts many customers and is worth studying in some detail.

Moreover, FirstEnergy has purchased the license to the FALLS system and has access to the NLDN data for the CEI territory. Yet, at this time, there is no one in the CEI organization who knows how to use the system or its analysis.

In conjunction with these efforts, CEI should augment this initiative to further reduce lightning-caused outages on feeder backbones by employing FirstEnergy's data, systems, and expertise, in general and specifically with FALLS, to identify additional opportunities for effective lightning protection of feeder backbones and to ensure a more holistic approach to lightning protection (verifying the type of construction as it relates to Basic Insulation Level, checking grounding in the area, assessing shared structures with respect to transmission and distribution, etc.)

This effort should be coupled with a collaborative effort to collect from industry and FirstEnergy sources a catalog of effective techniques for lightning protection in various situations and a tracking program to determine the relative effectiveness of the various measures.

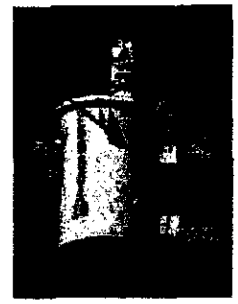
Repair Pole and Pole-Top Fault-Causing Equipment Problems

Section 5.3.4 offers an assessment of CEI's adherence to the Electric Service and Safety Standards Inspection Program, as well as the overall effectiveness of its Field Inspection Program. And, in so doing, a number of issues around the Distribution Circuit Inspection Program are addressed.

Currently, CEI (as well as the other FE Operating Companies) adhere to a 5-year inspection cycle for all distribution circuits. Independent of these requirements, we suggest an approach that is more selective and prioritized. In short, we recommend that CEI apply an inspection and repair prioritization scheme consistent with the overall theme of this assessment. Specifically, this means the highest priority will be given to the feeder backbone, second priority will be related to those areas where customers are experiencing multiple outages, and last priority to areas that have lesser reliability impact. The frequency of inspections would necessarily be accelerated in the higher priority areas and extended for the lower ones. Keep in mind that other inspections and activities are ongoing (including the newly assigned Asset Management Circuit Health Coordinators), to ensure these lower priority circuits still receive adequate attention.

Animal Mitigation

Figure 5-3
Typical Animal
Contact



The most typical case of an animal-caused outage in the eastern United States is a squirrel (or sometimes a bird or a snake; and at CEI substations raccoons) that causes an outage on an overhead distribution transformer by sitting on the top of the tank (which is grounded) and making contact with the primary or lead above the bushing (or sometimes through the lighting arrester attached to the tank). Sometimes the outage is self-clearing as the squirrel is shocked out of position or burned through, but often some permanent damage is done or at least a fuse is blown and a crew must be dispatched.

When there is this type of animal outage, (i.e., failure on a distribution line transformer), the number of customers interrupted is necessarily limited, perhaps only one to four if there is no secondary rack involved as there might be in row housing. As such, avoiding these types of outages in a systematic way is generally not thought to be cost effective except that each time a crew responds to such an outage it should deploy an animal guard, since it is well known that animals tend to repeat their paths to and from food, water, and shelter, and a device that has an animal failure once is likely to have one again (even if the animal that caused the first one met its demise therein).

Trouble crews should have animal guards in the truck at all times. Note that it is especially important to avoid repeat outages on the same device because the same customers will be affected and their tolerance for outages will be tested.

Besides transformer outages caused by squirrels, there are line and substation outages caused by squirrels, birds (especially large-winged raptors), snakes, raccoons, etc. Protecting line and substation equipment can be difficult, but there are discs and other devices intended for the purpose. Because of the number of customers that may be involved in such outages, it can be valuable to deploy such guards and devices as may be found to be effective. In substations, a combination of enhanced fence protection as well as various discs has proven effective, the latter being deployed when the equipment is out of service. CEI has deployed such methods effectively.

One of the best things that can be done to reduce squirrel-caused outages is to reduce their ease of access to lines by proper tree trimming. As anyone with a bird feeder knows, squirrels can jump, climb upside down, and do amazing things to get to food, but they will often follow the path of least resistance (and highest protection from predators such as cats – hence walking on lines) and so reducing easy access to and from lines by tree trimming can be effective in reducing outages.

CEI is already adept and diligent at deploying animal mitigation. Specifically, within the Distribution Line/Circuit function, CEI has integrated an Animal Guarding Program with their Inspection Program and Substations that has utilized planned and forced outages to apply the material already in stock. Some animal-caused outages will always occur. If these occurrences are mainly to the distribution overhead line transformers that have not failed before for the same reason that would be considered more than sufficient.

5.2.3 Feeder Sectionalizing, Including Fusing and Installing Reclosers

The single most cost-effective program that can be implemented to improve interruptions as measured by SAIFI and therefore SAIDI is feeder sectionalizing. This can include deployment of additional reclosers, fusing unfused taps off of the mainline and major branches, as well as distribution automation, which involves a more sophisticated system of switches and communications for controlling them.

<u>Installation of Reclosers</u>

Note that a standard recloser does not have communications capability but uses its own relays to sense current upstream and downstream in order to determine how to operate. It does not know the state of other switches, only the state of the current on the line to which it is attached. It is nevertheless quite effective, and sometimes more so than a fully automated system, because many utilities in the past have found the radio communications for a remotely controlled switching system to be problematic.

For most utilities (including CEI), over half of all customer interruptions are due to outages on the feeder backbone, not the taps. There are typically more outages on the taps, but they interrupt much fewer customers (as noted in Section 3.0). For example, a typical feeder might have 500 to 1500 customers connected to it. When the main backbone goes out, all of those customers are out. A tap might have as many as 500 customers of its own, on a very large feeder, and such taps deserve their own attention almost at the level of a feeder backbone. However, most taps involve only about 50 customers.

As such, smaller taps are an order of magnitude less in importance. Moreover, predicting which tap will fail may be difficult (although we address such measures below in the section on worst-performing devices). By contrast, feeder backbones are very visible, limited in scope, and provide an excellent target for remediation.

The remediation of outages normally involves a thorough analysis to determine the cause of outages and remediation typically solves only one problem, e.g., trees, lightning, or animals. For feeder backbones, however, sectionalizing represents a strategy that works for all causes. Whether a car hits a pole or a tree falls on the line, sectionalizing will reduce the number of customers affected by any outage to the backbone.

It is precisely because sectionalizing is so indiscriminate with respect to root cause that it is also ineffective with respect to root cause – but not with respect to the number of customers affected. Sectionalizing does nothing to eliminate outages, i.e., addressing the underlying fault condition that is the cause of customer interruptions. In that sense it is ultimately a <u>mitigation</u> strategy rather than a remediation strategy, if those terms can be used in a rigorous sense to imply that one only reduces the impact of an outage whereas the other addresses the root cause. Yet it is a very effective mitigation strategy and can have a significant effect on SAIFI.

The clearest example would be a feeder with no reclosers on it. Assume that the feeder serves 1,000 customers. It is reasonable to assume that its customers are distributed evenly across its length, and that outages are also proportional to length as well. In a given year, if it has two backbones outages, one on the front section of the feeder and one on the far section, those two outages will cause 2,000 customer interruptions, and will cause the SAIFI for those customers to be at least 2.0, i.e., before adding all of the other outages that occur on taps, transformers, and services.

If one were to deploy a recloser at the mid-point of the feeder backbone, then one of those two outages, the one on the far part of the feeder, would interrupt only half the customers, because the customers on the near end would be unaffected. Depending on the operational scheme of the recloser, they might not even see a momentary outage and certainly they would see no sustained outage. For the customers on the near end, deployment of this device would cause their interruptions to decrease by 50 percent, and for the feeder as a whole (i.e. for all of its customers averaged together) the improvement would be measured as 25 percent.

Of course, the actual results would likely vary. If both of the outages were to hit the near end of the feeder, there would be no improvement. If, however, both outages hit the far end, there would be a 50 percent improvement for the feeder, and 100 percent for those on the top end. Likewise, if the distribution of customers is not even, the results would vary as well, but the latter can be controlled by the reliability engineer's placement of the recloser. When the feeder already has a number of reclosers on it, the advantages of an additional recloser must be weighed in terms of the number of customer interruptions that might be avoided. In this case, each zone between reclosers can be evaluated for possible improvement the way the analysis above looks at one feeder. Clearly, only in zones with a large number of customers and outages would it be worth employing this strategy.

Depending on the configuration of nearby feeders, it may also be possible to put a tie recloser at the far end of the feeder that would allow the same kind of result for those at the far end of the feeder, i.e., that when a fault occurrs on the near end, the mid-point recloser opens, the tie closes, and service is rapidly restored to customers on the far end, while the near end is isolated dead. The customers on the far end will see a momentary, but not a sustained outage. Note that in this way, deployment of two reclosers, one at the mid-point and a tie at the far end, could improve the overall feeder performance by 50 percent on average and for all customers on that feeder. In some cases, though, ties at the far end will not be available or will require the more advanced control afforded by a fully automated system with radio control between units.

A further advantage to this strategy is that it normally does not require universal deployment to be effective. Typically, only a small percentage of feeders have multiple backbone outages each year, and many feeders have a history of no backbone outages for years. Clearly, careful choice about where to deploy the reclosers can lead to an even more cost-effective program.

Another advantage of any backbone-based strategy, be it sectionalizing or even a backbone-emphasized tree program, is that backbones are often the point of connection for commercial customers and vital community services like hospitals, large public buildings, transit stations, water pumping facilities, and key traffic signals. Those who put extra importance on 'community continuity' and would insist on higher reliability for such facilities would see the advantage of a strategy that emphasized backbone reliability. For a utility concerned about its perceived reliability as well as its actual, it is worth noting that people often consider area-wide outages such as are caused by feeder backbones to be more indicative of poor reliability than similar number of isolated customer outages on small taps.

In reviewing the over 1,000 4kV and 13.2kV circuits within the CEI system, 825 circuits do not have reclosers installed. Over 350 of these circuits serve more than 500 customers (considered by CEI as the optimum cut-off point for considering the installation of reclosers). Figure 5-4 provides a tabulation of these circuits by number of customers and voltage class:

Figure 5-4
CEI Circuits Without Reclosers

Number of Customers	4kV Circuits	13.2kV Circuits	TOTAL
>2,000	0	24	24
1000-1999	37	64	101
750-999	80	16	96
500-749	113	19	132
TOTAL	**230**	**123**	**353**

Notwithstanding that many of these circuits may have experienced few, if any, backbone outages and some could be underground, this figure does suggest an opportunity to further sectionalize the feeder backbone and reduce the number of customer interruptions.

Another item to consider is the replacement of existing three-phase reclosers with single-phase reclosers (as well as using banks of single-phase reclosers for new recloser installations). Like many of our recommendations, this option should be considered on a circuit-by-circuit basis. Clearly, the advantage of reducing the number of interruptions by two-thirds is attractive. However, depending on the needs of the customer on that circuit, the impact to a major commercial or industrial customer that requires all three phases needs to be weighed against this benefit to other customers on the circuit.

Relaying/Over-Current Protection

Utilities use a variety of relays arranged in 'schemes' to protect equipment from damage due to a fault or other operating condition. Some relays sense high temperature in power transformer oil, a sudden pressure change in the oil tank that could signal an imminent explosion and some sense voltage differentials. But these tend to be on power transformers in the substation. For distribution circuits, the main reason for relaying is protection from an electrical fault on one or more of the phases, and the main sources of protection are fuses and over-current relays that open fault-interrupting devices such as circuit breakers and reclosers.

Fuses blow when they have seen too much current due to a 'short circuit' (fault), and circuit breakers open under the same conditions. Once the fault is cleared, fuses that have blown are destroyed and must be replaced with another of the same size and type, and circuit breakers or reclosers can simply be reset. As simple as that seems, there are considerable differences in how utilities design these over-current protection schemes. The issue revolves around how many times a circuit breaker or recloser will automatically re-close and how long will be the delay between re-closings. A Typical scheme might be "four trips to lockout" with three re-closing intervals of 2-30 seconds each.

To further complicate the matter, there is the distinction between an instant trip and a timed trip. An instant trip is one in which the relay sends the signal to open as soon as the relay detects current in excess of a preset threshold. A 'timed' or 'time delay' trip is one that waits for a period of time before sending the trip signal. The period of time that the relay waits is dependent on how much current it sees, recognizing that fuses follow what is called a time-current characteristic curve in terms of how quickly they will blow, with the same fuse blowing faster if it sees more current and slower if it sees less. This is referred to as an "inverse time" characteristic, meaning the more current it sees, the faster it operates. With the instant trip, fuses will not have seen enough time-current to blow, so the instant trip is called 'fuse saving', allowing the circuit breaker or recloser to potentially clear the fault before the fuse blows. The timed trip is called 'fuse sacrificing' because it intentionally waits long enough for at least some of the fuses to blow before opening the device.

At CEI, as at other utilities, the protection schemes vary between different situations, with some general patterns or guidelines by voltage. For example, CEI's 13.2kV protection utilizes 4 over-current trips to lockout, with three re-closing intervals (wait times) of 2 seconds, 35 seconds, and 45 seconds. The first over-current trip is instantaneous (no intentional time delay), followed by 3 time-delay (intentional time delay) over-current trip operations. Each re-closing interval is the time the feeder is de-energized and is unique, and <u>not</u> a summation of the previous time(s).

The reason for the multiple trips and re-closes is that studies have shown that a very high percentage of faults on distribution circuits (especially overhead) are temporary, in the sense that one operation cycle of opening and re-closing is sufficient to 'clear' the fault, i.e., after re-closing, the device no longer senses a fault. Reasons include branches that receive enough current to singe themselves into a state of being burned back away from the line, or burning enough to lose strength, therefore breaking into pieces and falling off of the line; squirrels or birds getting enough of a shock to be thrown off of the line or fall dead or stunned from a fault-causing location; lightning-caused voltage surge on a line sufficient to overcome the insulation - once a path to ground is established, even after the surge is gone the current will follow that path until it is interrupted. The trip and re-close may be enough to break the path and ensure that once the lightning is gone and the fault no longer remains (presuming no physical damage occurred during the fault) the re-close will be successful.

There is no real controversy around multiple trips and re-closes, except that the industry recognizes there are instances when it should not be used. For example, for circuits that are completely underground, most faults are permanent, and some may be very high current faults that could damage equipment each time they are energized. Consequently, most utilities (CEI included) will not re-close on a totally underground feeder, i.e., instead they will "immediately lockout". CEI's 11kV feeders are treated this way, as well as some of the 4kV and 13.2kV.

There is still some controversy within the industry regarding the use of the instant trip. These are some of the considerations:

- The instant trip could be followed by an instant re-close, i.e., allowing the whole open and re-close operation to take place as fast as physically possible, which may be a little less than a second). Most question the rationale since an electrical arc that may have formed in the air or on wood, may not have had enough time to dissipate. When the re-close occurs, the fault will not have cleared, and the path to ground will be re-energized. Hence, when discussing an instant trip, it is generally teamed with a timed re-close that takes place after a sufficient timed interval.
- The instant trip and timed re-close is presumed to prevent damage to components of the system, e.g., power transformers, by limiting the amount of time that the fault current is present.

- The instant trip and timed re-close causes a 'momentary interruption' that usually causes the clocks on older models of electronic appliances to reset, which can be a nuisance to homeowners (and a similar problem exists for industrial and commercial equipment that is not properly equipped with capacitors).

The instant trip and timed re-close is designed to be 'fuse saving', in the sense that it gives the automatic device (circuit breaker or recloser) the chance to clear the fault before the fuse has seen enough current and has had time to blow. Thus, in thunderstorms with lots of wind and lightning, it is a 'good thing' to have the instant trip and timed re-close on in order to avoid having to send out trucks merely to change fuses. The downside is that if the fault was going to be permanent anyways, it would have been better to blow the fuse, isolating only that tap and sparing the rest of the customers on the circuit the nuisance of seeing a momentary interruption.

Our general recommendation with respect to whether or not to set the instant trip and timed re-close is that it is a decision that should be made on a case by case basis, considering the nature of the circuit and its customers, the history of success with instant trip and timed re-close on that circuit, and the damage that might be done to equipment if the instant trip is not set. Currently, CEI is doing the following (by circuit voltage):

- **13.2kV Circuits:** In response to customer complaints about momentary interruptions, the instant trip has been disabled on 33 of the 398 13.2kV circuits. For those that are underground, there is no re-closing anyway.
- **36kV Circuits:** 3 instant trips with timed re-close (1 and 15 seconds). These circuits are generally not fused (i.e. no coordination issues).
- **11kV Circuits:** Underground, with no automatic re-closing used. All faults assumed to be permanent using 1 instant trip to lockout.
- **4kV Circuits:** Several tripping schemes based on whether a feeder is old or new, ranging from letting the circuit breaker do the work to a variety of instant trip and timed re-close scenarios.

We recommend that CEI perform studies of the re-closing success on feeders with the instant trip. This will help in assessing whether the nuisance of the momentary interruptions caused by the instant trip are warranted by a high success rate in clearing temporary faults (expect that nearly 50 percent of the instant trips will be followed by a successful (timed at 2 seconds) re-close). It may also be useful to see how this varies in storm or non-storm conditions.

The industry has discussed the concept of 'reactive relaying' or 'adaptive relaying' in which the instant trip feature would be set only as a storm approaches and then disabled afterwards. This concept has merit and FirstEnergy has a pilot system that would do this automatically (we feel operator control of such a system is adequate and probably preferred), but the ability to use it is conditioned on having substations with modern electronic relays, and as yet there are few of those at CEI. We believe replacing old relays is warranted at the rate CEI is currently doing so, along with circuit breaker replacement.

Distribution Automation

The term 'Distribution Automation' refers to a concept of a distribution system that has a high degree of automated switching that occurs through communication between each switch and either other switches, as in a decentralized scheme, or between each switch and a centralized control center, or perhaps one per area. There is a fair amount of confusion associated with the term because it is sometimes applied to the installation of regular reclosers that have no communication capability but do allow automatic switching in the event of a fault. It can also be confused with various other "Utility of the Future" architectures such as automated meter reading, including two-way meters with demand response capability, automatic outage detection, distributed generation, plug-in hybrids, etc.

The industry has struggled over the years to develop a common, widely-used technology platform for Distribution Automation. Even at this time, there is still debate about whether the communications technology should be broadband over a power line, dedicated fixed radio network, spread-spectrum radio, or cellular internet. There is also debate about whether the switches should be able to interrupt fault like normal reclosers or whether they should operate dead like motor-operated disconnect switches. Both schemes have proven effective, but for different utilities with different goals for Distribution Automation.

There have been a number of instances in which a utility installed switches and a radio system, only to find that this approach did not work well. They then had to re-design the system, in some cases requiring virtually starting over with new equipment while the old equipment went largely unused. This has made many utilities wary of investing much in Distribution Automation until the concepts are proven. As a result, the industry is full of pilot projects and not many full installations.

For CEI and FirstEnergy, the project to choose a technology for possible implementation of Distribution Automation is in the pilot stage (with some installations of Radio-Controlled Switches and Automatic Transfer Schemes on some targeted circuits outside of the CEI system). It is reasonable to assume that implementation is at least three to five years away. At this point we recommend that CEI work with FirstEnergy to formalize a strategy with respect to Distribution Automation.

5.2.4 13.2kV and 4kV Circuit Considerations for Protecting the Backbone

The 13.2kV circuits, being typically long overhead runs with many underground and overhead taps, are ideal for both hardening and sectionalizing. The overhead system should be prioritized by finding those protective zones that have a large number of customers served and a history of backbone faults in that zone.

The 4kV circuits are less likely to benefit from sectionalizing, because they are short lengths and they have higher densities. They are basically small circuits; the average 4kV circuit that experiences a total circuit lockout involves only 380 customers. Of course, some opportunities may exist for selected 4kV circuits that are not typical, but of the over 700 4kV circuits, only 21 are more than 15 miles in length, all of them in the Ashtabula and Concord districts, and none of them appear to be candidates for further sectionalizing (based on the average number of customers interrupted per outage). CEI should verify this assumption on the 230 4kV circuits without reclosers that serve over 500 customers.

Hardening the backbone, on the other hand, is likely to be reasonably cost-effective for the 4kV circuits, since the entire circuit is typically only 5 miles long, with an even shorter backbone. The challenge, often, would be that the backbone, while it starts at the substation and is probably on a major thoroughfare that is not heavily treed, may quickly dip into neighborhoods that have tree-lined streets with extensive canopies of venerable old growth that communities do not want to see heavily trimmed. In such instances, community communication programs can be effective in reaching a proper balance between concerns about tree preservation and electric reliability. And, it is important to emphasize that a backbone hardening program does not need to target every tree, but only those on the three-phase backbone, which could leave many streets with only the existing normal contact-based trim.

Another aspect of the 4kV system that is worth noting is that, since the 4kV feeders are more numerous, their exits from the substation often need to be underground, perhaps going a quarter-mile or more underground before reaching an overhead riser. As a result, cable failures on the exit cable, which would necessarily cause a lockout of the entire feeder, can be a common problem and one that will get worse as the very old cable in the similarly old conduits begins to reach the end of its useful life. Programs to inspect, maintain, and even test such cable can be effective in preventing outages of this type. This is just a special case of the strategy to 'harden the backbone'.

5.3 Non-Feeder Backbone Initiatives

The following discussion addresses the initiatives related to improving overall system reliability, independent of whether the circuits addressed are part of the feeder backbone. Should they be, then the approaches and recommendations listed above (section 5.2) will likely encompass the intended purpose of the following programs:

- Worst Performing Circuits
- Worst Performing Devices (Repeat Offenders)
- Underground Cable Replacement
- Electric Service and Safety Standards (ESSS) Inspections and Repairs

5.3.1 Worst Performing Circuits (Rule 11)

Virtually all utilities have programs to remediate their worst-performing circuits, and many state public utility commissions require such programs and detailed reporting on their progress (such reporting is an integral part of the Rule 4901:1-10-11 of the Ohio Administrative Code). The measurement of what constitutes a 'worst-performing' circuit varies, but is usually keyed to poor average customer interruption frequency and duration for the circuit, measured analogously to system average interruption frequency and duration, i.e., SAIFI and CAIDI). In fact, it is typical to call the average interruption figures for a circuit the 'Circuit SAIFI' and 'Circuit CAIDI', even though these are system measures.

CEI used to use its CRI (Customer Reliability Index) to select the worst-performing feeders. It now uses the contribution of each feeder to SAIDI. This is a sound approach, since the emphasis of the company and PUCO is on improving that index and its underlying components, SAIFI and CAIDI. It is important to note that this means that a feeder with a small number of customers might have a higher circuit SAIDI and yet not make the list before another feeder with a large number of customers and a poor, but not as poor, frequency and duration. This phenomenon is well understood in the industry and the choice of the "larger impact" feeder is appropriate for a worst-performing feeder program. When this approach is used, it works best when combined with a worst-devices approach as described in the next section.

In section 3.0, the analysis highlighted the 25 worst performing 13.2kV and 5 worst performing 4kV circuits based on distribution customer minutes of interruption in 2006. Figures 3-18 and 3-19 offered some interesting insights:

- Not surprisingly, the list of 13.2kV circuits contains many long feeders (9 are greater than 50 miles). The more miles of exposure a feeder has, the more likely it is to be exposed to fault-causing influences. And, the longer the feeder is, other things equal, the more customers it has connected to it, and the more that can be interrupted by a fault on the backbone. Countering that notion, though, is that two-thirds of these feeders are in rural areas. In fact, if a feeder has too many customers, the normal size of conductor will not carry the load, so one can assume that long feeders are more sparsely populated.
- The average distribution circuit across CEI is 21 miles and has 1125 customers. For this list of "worst performing" circuits, the average is 40 miles with over 2100 customers served.

As with the feeder backbone (of which many of these circuits are part), one of the best remedies is sectionalizing. Given the relatively low percentage of 13.2kV circuits with reclosers already installed (123 circuits), this approach merits some attention. Note however, that even those that have had some sectionalizing done may not have had them installed with a reliability strategy in mind. Rather, the reclosers may have been installed because of the sheer length of the feeder – to compensate for the inability of the station breaker's relays to detect a fault at the end of the line. Hence these reclosers may have been deployed to allow fault-sensing relays to be closer to the fault; and as such may not be optimally placed based on number of customers.

With this in mind, one cannot be certain that this list presents the real opportunities. A detailed analysis of the configuration of each feeder would be necessary to confirm the opportunities. Clearly, the list suggests that such an analysis is warranted. What this brief discussion demonstrates is that the job of finding the right solution for a worst-performing circuit is not trivial, and requires the expertise of a reliability engineer (or technician) to properly discern whether and where a recloser would be effective, and also what remediation of causes of outages would be cost-effective. CEI needs to ensure that its Reliability Engineers are of sufficient number and expertise to address problems on the CEI feeders.

5.3.2 Worst-Performing Devices (Repeat Offenders)

As discussed in section 3.0, about half of the outages have little impact on system reliability as they impact only 1 to 10 customers. As such, they need to be addressed in the context of avoiding repeat offenders, i.e., worst-performing devices, so as to avoid customer satisfaction issues for individual customers or small groups, but not as part of the strategy to address system reliability as measured by SAIFI and CAIDI. As a matter of fact, emphasis on these measures will not necessarily lead one to identifying these devices, because in some cases the number of customers behind a device might be small, and therefore even multiple interruptions might not lead to large impacts on SAIFI and CAIDI. Nevertheless, because all companies and their regulators are appropriately dedicated to customer satisfaction and to avoiding complaints about service, it is important, while focusing on SAIFI and CAIDI for overall performance, that a separate focus be maintained on avoiding the most serious problems with repetitive outages of any device.

In this regard, we note that such a program need not be ineffective from a cost point of view. While it may not be cost-effective to try to avoid every outage on every device (especially when there is no obvious pattern that would lead one to target a class of devices as being most likely to fail), a program that focuses on repeat-offending devices is likely to be cost effective because it targets those few devices that have demonstrated a tendency to fail repetitively. Indeed, since each outage requires the utility to deploy resources to respond, if some effort can be made to fix the problem the first time (or with a single follow-up visit) the cost of the remediation may well pay for itself in short order through avoidance of future restoration trips (to say nothing of the cost of dealing with customer complaints.)

There are programs available to assist CEI in this endeavor to proactively identify pockets of poor performance at the customer level; and is so doing, provide the information system architecture to record outages experienced at each customer location, potentially transitioning CEI from solely a system-wide view of reliability (SAIDI, CAIDI, and SAIFI) to include a customer-centric orientation (CEMI).

These programs map every customer to the transformer that serves that customer, and then maps each transformer and upstream device into a total load flow through each feeder. Each outage then can be shown as an outage not just to its own device, but also to all devices downstream from it. When this is done for all outages, it is possible to accumulate (for each customer premise) the number of times the power is interrupted in a given period, whether it is due to the service connected to that location, the transformer to which the service is connected, the tap to which the transformer is connected, the upstream tap(s) (if any) to which the smaller tap is connected, the upstream recloser(s) (if any) to which the larger tap is connected, and then the feeder breaker. An outage to any of these devices will cause an outage to the customer so connected.

The capability to develop this type of program resides within FirstEnergy, and we recommend that CEI tap this capability to develop a worst-CEMI program (similar to a Worst-Device Program). Without compromising its primary focus on reducing SAIFI and CAIDI, CEI should monitor those devices that have experienced repetitive outages and work in a cost-effective way to remediate them, relying on the efforts of the reliability engineer (or in some cases, the troubleshooter who responds to the calls) to identify the root cause in each case and take cost-effective steps to replace and/or repair them. A criterion along the lines of reviewing all devices with 2 failures in a month (or 3 within a quarter) would seem appropriate.

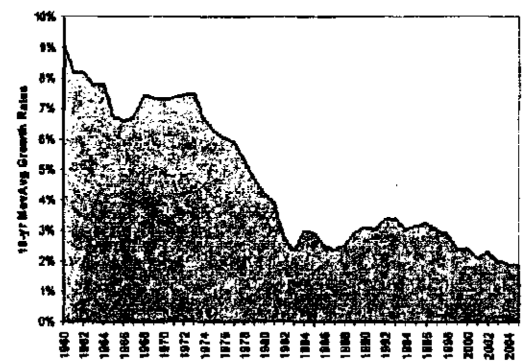
Note: This technology is available and already in use at CEI. FirstEnergy's PowerOn OMS data is used to map CEMI in the GIS View application. This provides a customer-level view of outage information and pinpoints worst performing devices.

5.3.3 Underground Cable Replacement

The electric utility industry in the United States had a growth spurt in the 1960's and 1970's (Refer to Figure 5-5) which led to the installation of a great deal of utility plant assets – generation, transmission, and distribution. At the same time, many suburban developments began to insist on the aesthetic appeal of underground utilities and some communities mandated that all new development be installed using underground cable. The industry responded with a new way of installing underground cable that became known as "URD" – underground residential distribution. It differed from the then-common method of installing underground cable in three ways:

Figure 5-5
U.S. Growth Trend

Growth of Electricity Usage (GWh) in US 1960-2005



- Direct buried, not in the typical manhole-and-conduit configuration,
- Insulation was solid dielectric instead of paper-insulated lead-sheathed cable, and
- Concentric neutral, since it was mostly single phased, and the neutral could be wrapped in a sheath around the conductor instead of as a separate conductor.

Unfortunately, at an early point in the deployment of this then new technology, the industry experienced some negative consequences. While the very earliest installations tended to be well done, a few years into the new era three developments took place that were to cause trouble in subsequent years:

- The solid dielectric material chosen was unjacketed, un-stranded, high-molecular weight polyethylene (HMWPE), a material that later proved to be failure-prone,
- The thickness of the insulation was reduced from 220mil to 175mil, and
- The burial was done in such a way that rocks and damaging bends were allowed to compromise the cable.

As a result, in the 1980's and continuing to the present, utilities found that cable that was purported to have a 30-year average life was failing in a much shorter time. URD cable replacement programs have become a regular part of almost every utility's budget, with many utilities adopting the rule that after two or three splices on a section of primary cable between two pad-mounted transformers, the cable is scheduled for replacement. Some utilities have also embarked on more aggressive replacement programs that address the worst loops or even subdivisions.

A subsequent wave of failures has occurred in some companies that switched from HMWPE to cross-linked polyethylene (XPLE) but still with the 175mil insulation and still unjacketed. There were also issues with 35kV URD and its connectors, some early versions of cable-in-conduit installed from a roll that had the cable and its conduit pre-combined, and other special failure-causing situations.

CEI's experience is consistent with the general industry pattern and the company is currently employing the "three-strikes-and-you're-out rule" for URD cable section replacement.

It is important to keep in mind that the main reason that utilities are replacing failure-prone URD cable is to avoid customer complaints from repetitive failures and also to save repair costs, since, once a cable starts to fail, the time between failures begins to accelerate. It is worth noting that the impact on SAIFI and CAIDI of a utility's entire URD replacement program, which may run from hundreds of thousands of dollars to even millions of dollars for some utilities, is usually not very significant. This is because URD cable runs tend to involve only 10 to 50 customers, so each outage is a small one. As such, even if a utility were to experience a few hundred URD cable failures per year, it would cause less than 10,000 customer interruptions or an impact of about .02 on SAIFI for a utility with 750,000 customers like CEI.

For this reason, we make no recommendation regarding CEI's URD cable replacement program except to keep doing replacement after three failures on the same section.

5.3.4 Electric Service and Safety Standards (ESSS) Inspections (Rule No. 26)

Rule 4901: 1-10-26 specifies the requirements regarding the Electric Service and Safety Standards (ESSS) Inspections that govern the various inspections performed by CEI, namely:

- Pad-Mounted Equipment Security Inspections (Internal inspections for all pad-mounted equipment and hand holes are conducted on a 5-year cycle)
- Pad-Mounted Equipment Internal Inspections (Security inspections for all pad-mounted equipment and hand holes are conducted on a 15-year cycle)
- Distribution Pole Inspections (Purpose of these inspections is to verify the integrity of in-service wood poles by identifying poles that require reinforcement or replacement)
- Capacitor Inspections (By improving the power factor, capacitors provide a cost-effective means to improve voltage, reduce losses, and reduce thermal loading of lines and equipment.
- Recloser Inspections (Annual Field Inspection)
- Distribution Circuit Inspections (Visual Inspection of overhead distribution facilities)
- Vegetation Management Program
- Substation ATR Program

Figure 5-6 provides a synopsis of CEI's performance in 2006 and 2007 program goals with respect to this program.

Figure 5-6
ESSS Inspection Summary

Program Name	2006 Performance		2007 Goals
	Goals	Actual	
Pad-Mounted Equipment Security Inspections	6236 Inspections	Met Goal: 6236 inspected	5996 Inspections
Pad-Mounted Equipment Internal Inspections	1066 Inspections	Met Goal: 1066 inspected	2142 Inspections
Distribution Pole Inspection (By Contractor)	38000 Pole Inspections	Exceeded Goal: 39771 inspected	39015 Pole Inspections
Capacitor Inspection	6278 Capacitor Unit Inspections	Met Goal: 6278 Inspected	6323 Capacitor Unit Inspections
Recloser Inspection	842 Recloser Bank Inspections	Met Goal: 842 inspected	872 Recloser Bank Inspections
Distribution Circuit Inspection	281 Circuit Inspections	Met Goal: 281 inspected	343 Circuit Inspections
Vegetation Management Program (By Contractor)	Maintain 293 Circuits	Did Not Meet Goal: 285 maintained (97%)	Maintain 248 Circuits
Substation ATR Program	98% of ATR do not result in an outage	Exceeded Goal: Of 2268 ATR, 2254 (99.4%) did not result in an outage	98% of ATR do not result in an outage

With respect to meeting the 2006 inspection goals, CEI met or exceeded expectations in every category except Vegetation Management (maintained 97% of the planned circuits). As a result of these inspections, there were a number of deficiencies (exceptions) found. Figure 5-7 summarizes the status of these exceptions (for both the 2005 and 2006 inspections).

Figure 5-7
2006 ESSS Inspection Close-Out Activities

Inspection	2005			2006		
	Findings	Closed	Open	Findings	Closed	Open
Pad-Mounted Equipment Security Inspections	43	43	0	617	362	255
Pad-Mounted Equipment Internal Inspections	0	0	0	0	0	0
Distribution Pole Inspection (By Contractor)	749	429	320	1687	391	1296
Capacitor Inspection	19	19	0	144	83	61
Recloser Inspection	0	0	0	4	4	0
Distribution Circuit Inspection	911	728	183	1560	320	1340

NOTE: The 2005 Findings are the carry-over from 2005 to 2006, all required to be closed out by the end of 2006.

However, with respect to timeliness in closing out previous year's deficiencies/ exceptions, CEI fell short of its internal requirements in both the Distribution Pole and Circuit areas. This is consistent with the results of our sample inspection of the Electric System Infrastructure (section 2.0), where there were a number of past due exceptions and of those, 41 were considered significant enough (from a reliability perspective) to warrant immediate attention (refer to Figures 5-8 and 5-9).

Figure 5-8
Lines/Circuits Inspection Summary of Results

Voltage	Circuit	CEI INSPECTIONS					UMS ASSESSMENT		
		CEI Inspection Date	Prior Identified Exceptions	Prior Identified Corrected	Prior Identified Uncorrected	Past Due Uncorrected	Exceptions Found	Total Remaining Exceptions	Open Reliability Exceptions
34.5kV	40004-0014	9/1/2004	0	0	0	0	23	23	14
	40181-0019	3/7/2006	22	19	3	NA	14	17	17
	40159-0021	2/11/2005	7	5	2	2	3	5	5
13.2kV	60152-0030	7/10/2007	6	0	6	NA	0	6	4
	40109-0008	12/1/2005	53	13	40	40	19	59	9
	40156-0010	7/1/2003	49	19	30	30	13	43	22
	40120-0019	3/7/2006	0	0	0	NA	13	13	11
4kV	40024-0003	3/1/2006	1	0	1	NA	6	7	7
	40218-0002	4/1/2006	101	18	83	NA	14	97	18
	40132-0003	9/8/2004	3	3	0	0	1	1	0
	40141-0008	7/1/2005	17	17	0	0	4	4	3
	40049-0001	6/1/2003	13	2	11	11	14	25	12
	40052-0003	7/10/2007	5	0	5	NA	5	10	3
	40190-0001	2/20/2007	16	10	6	NA	0	6	2
	40124-0003	11/1/2005	10	9	1	1	3	4	3
TOTAL			303	115	188	84	132	320	128

Figure 5-9
Reliability Related Exceptions Analysis

Exception	MOST RECENT CEI INSPECTION				
	2003	2004	2005	2006	2007
Conductor on Cross Arm	1	0	0	4	1
Broken Cross Arm	2	7	5	11	0
Arrestor Open	1	2	1	4	2
TOTAL	4	9	6	19	3
Open Reliability Exceptions	**34**	**14**	**20**	**51**	**9**
Open Exceptions	**68**	**24**	**72**	**134**	**22**

And, though the overall performance in terms of meeting the inspection requirements in 2006 was encouraging (met or exceeded the program requirements in all areas except vegetation management where 97 percent of the planned circuits were reported maintained per specification), there is some concern warranted in that UMS found a number of exceptions not reported by the CEI inspectors.

CEI needs to remain focused on improving its performance with respect to meeting the mandated ESSS inspection requirements. And, every indication is that CEI Management is committed to making that happen. However, we do need to point out that any correlation between the exceptions noted in these inspections and overall system reliability lies in understanding the accumulated effect of many exceptions and the compounding impact they can have on the overall material condition of the system; and the long term effect they can have on the goal of meeting the reliability targets and maintaining them for a 10-year period. There is little, if any, correlation between these same exceptions and current reliability performance.

As CEI maintains their commitment to the ESSS program as currently designed, two of the programs (Distribution Pole Inspections and Distribution Circuit Inspections) need to be discussed in terms of better understanding their potential (or lack thereof) to improve reliability and how they might better fit into the philosophy presented in this study.

<u>Distribution Pole Inspections and Replacement</u>

All utilities have dealt at one time or another with wood pole inspection programs. Like tree trimming, this O&M-funded program has been cut at some utilities in times of budget stringency, but it is always something that is raised as a candidate for restoration when excess funds re-appear. The typical program involves inspecting 10 percent of a utility's poles, i.e., all poles on a ten-year cycle, using either its own personnel or more typically a specializing service contractor like Osmose.

Figure 5-10
Illustrative Pole Rot

Each inspection would involve an examination of the pole for ground line rot and possible pole-top rot. The method may involve 'sounding' i.e., hitting the pole with a hammer-like tool to detect hollowness, or a more scientific approach involving boring into the wood and taking a sample.

Some utilities take this opportunity to treat the pole with a preservative that is expected to retard rot and extend the life. If the pole is found to have lost too much of its inner core to be structurally sound (Figure 5-10), it is marked for replacement or in some cases merely reinforcement using a metal casing to be strapped around the base of the pole.

Data from many different utilities confirms that pole rot is rarely a cause of outages. Frequently in-line poles that have been hit by a vehicle and are broken at the base may still hang from the wires, and a pole that is completely rotten will not necessarily fall over unless forces are applied to it because it is at a turning point in the line or catches the wind in a particular way. Even if a pole were to fall, it would often just break the conductor and be in that sense no worse than if a large tree branch fell on the line. In fact, the main reason utilities inspect wood poles for rot and replace the rotten ones is to preserve the long-run condition of its assets and to avoid being held liable for negligence in the event a pole were to fall (even if hit by a vehicle) and injure someone.

The risk of such legal action is a common driver for these programs. For example, the risk of a single $1 million-dollar lawsuit can justify a significant pole inspection and replacement program (approximately $25 per inspection and $2,000 per replacement).

Because the emphasis of this review is on ways to improve SAIFI, and CAIDI, we make no recommendation regarding CEI's pole inspection and replacement program, other than to remain on its 10-year inspection cycle.

Distribution Circuit Inspections

Many utilities have instituted and then scrapped programs for regular overhead line inspection of its distribution circuits, typically on some cycle between 5 and 20 years. At present, the California utilities have approached this program with renewed vigor under the insistence of the state public utility commission. The problem with these programs is that they tend to generate a significant number of repair work orders which in principle become work for line crews and trouble crews to do in their 'downtime'. Typically, this work backlog often becomes unmanageable and the value of the program in meeting its intended objective is questioned. This is clearly the case at CEI, as the ESSS program mandates a complete inspection on a 5-year cycle with the added requirement that all exceptions be addressed within a prescribed time frame, independent of their impact on system reliability. It should be pointed out that the National Electric Safety Code does require utilities to 'regularly inspect' their lines. However, many interpret this requirement to be satisfied by a combination of tree trimming programs, outage restoration activities, pole inspection programs, and driving by the area on other duties; consequently, a separate inspection program on a specific cycle is considered unnecessary.

Frequently, and to the surprise of some managers, the termination of such line inspection programs has no appreciable impact on reliability. This is typically because there was no prioritization of the work generated by the program and most of the work was of a nature that would not actually avoid an outage any time soon, e.g., tightening a guy anchor, replacing a split cross-arm that would take ten years to get worse, etc.

Utilities have realized some success with line inspection programs that were highly selective and prioritized. The typical structure of such a program is to assign a high priority to conditions that are likely to lead to an outage within the year, middling priority to a condition that might lead to an outage within the next cycle, e.g., ten years, and the lowest priority to something that is not likely to cause an outage but is simply a variation from standard or new construction. Each of these priorities would necessarily have a different time period in which to respond. The classic example is a split or broken cross-arm – a broken cross-arm, hanging from the wires and compromising the distance between phases, would be seen as a high priority. A merely split cross-arm would be seen as a middling priority.

Another example is a leaning pole. Though unsightly, they rarely cause outages. Only when the stresses are such that the condition is likely to deteriorate rapidly (i.e. in a storm) would a merely leaning pole pose an imminent threat of an outage.

Our recommendation is that CEI's program be redirected from a 5-year program that inspects all lines to one focused on the backbone and worst performing circuits and devices on even a more frequent basis, extend the cycle on the other circuits; and then institute a priority system consistent with that presented above. In that manner, CEI can focus its attention on ensuring all pole and pole-top fault causing equipment problems are addressed, and then exhibit some latitude in managing the balance of any inspection exceptions.

5.4 Long-Term Approach

Subsections 5.1 through 5.3 identify the steps necessary (along with rationale) to meet the PUCO approved targeted SAIFI of 1.0 by December 31, 2009. And, implemented correctly, the recommendations contained therein will support the longer term goal of CEI sustaining this performance for at least 10 years. Our view, however, is that additional actions will be necessary to achieve this vision. There is a significant difference between meeting reliability targets at a given point in time (somewhat dependent on weather patterns and the extent to which a storm or two may be excluded), and having a system (and accompanying processes) that can sustain performance over an extended period of time (virtually independent of weather). The following discussion addresses two longer range processes and/or programs, which, when integrated within a strategic asset management framework, provide a foundation on which to first improve, and then maintain top-quartile performance with respect to service interruptions (as measured by SAIFI):

- System Capacity and Overload Forecasting ensures that the electric system is properly configured to meet the projected load requirements; and that there is a process in place that allows for timely and proactive adjustments should the planning assumptions change.
- Refurbishment and Replacing of Aging Infrastructure, a challenge across the industry and within CEI in particular, acknowledges that renovation and repair of the electric distribution system has not kept pace with the gradual degradation and increasing obsolescence of critical equipment and components.

5.4.1 System Capacity and Overload Forecasting

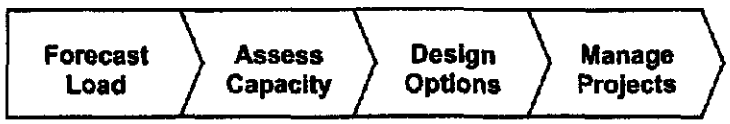
The purpose of this section is to review CEI's distribution load forecasting processes to determine if they are appropriate, and if adequate resources have been allocated to accommodate any growth. Our analysis includes a review of the forecast horizon, level of detail, accuracy and credibility of the forecasts, with a view as to how this information is integrated into plans for capacity additions to the distribution infrastructure..

This review is structured around the flow of the capacity planning process, with specific findings and recommendations at each step.

Capacity Planning Process

Capacity Planning can be viewed as a four-stage process, as depicted in Figure 5-1 below:

Figure 5-11
Capacity Planning Stages



Forecast Load: The load forecasting phase of the capacity planning process allows capacity planners to predict with reasonable accuracy the demand for electricity in a given area and for each distribution circuit, reflecting both normal increases in customer consumption as well as known incremental one-time additions of load. In order to accomplish this, there are 3 steps that need to be accomplished:

- Monitor Latest Peak Load
- Forecast Load
- Compare with Local Business and Economic Data

Monitor Latest Peak Load

CEI utilizes demand metering at all of its substations to obtain peak load information. Demand ammeters are installed on all circuits and transformers. The meters are read monthly (more frequently during summer months at heavily loaded substations) and the data is entered into an FE database system (SDCS). This database system is used to monitor potential overloads on circuits and transformers. Load monitoring devices (load loggers) are installed on circuits to monitor load at step-down transformer locations (generally 13.2 kV to 4kV).

CEI also uses metering at its substations to monitor VARs. This data is recorded in an FE database (MV90). The database is used to determine VAR requirements on circuits and substations. It is also used to determine appropriate locations for installation of capacitors required for overall system VAR support. Overall system VAR requirements are provided by FirstEnergy's Transmission Planning & Protection group.

Additionally, CEI has extensive coverage of SCADA monitoring down to the circuit level. CEI relies on SCADA data to monitor instantaneous loads during extremely hot weather.

Forecast Load

CEI records measured peak transformer and circuit load information in SDCS. SDCS information is verified and adjusted by Engineering and loaded into LFDMS. LFDMS provides several models (straight line, exponential, etc) for projecting future loads. Large customer loads are added to the forecast

Compare with Local Business and Economic Data

CEI's territory is currently showing little (and in some instances negative) growth (Figure 5-12). However, if the past trends change, this type of information needs to be factored into the load forecasting process. New developments can add as many as 1000 residences every year; and a commercial development such as a one-million-square-foot mall can potentially add 10 MVA of load to the area, and an average-sized hotel will typically add 500 kVA of load.

Figure 5-12
Customer Count and Growth Rate by District

District	2006 Avg. # Customers	2002-6 CAGR
ASHTABULA DISTRICT	62,136	1.2%
BROOKLYN DISTRICT	135,553	-1.0%
CONCORD DISTRICT	67,618	0.8%
EUCLID DISTRICT	53,302	-1.9%
MAYFIELD DISTRICT	95,667	0.4%
MILES DISTRICT	121,680	-1.4%
SOLON DISTRICT	28,491	0.1%
STRONGSVILLE DISTRICT	104,473	0.5%
WESTLAKE DISTRICT	78,106	0.6%
CEI Total	747,026	-0.2%

Planning accuracy would be hindered if CEI were not informed of any changes in load requirements: Sudden prosperity or an economic downturn in an area can hinder effective load forecasting. For example, management at a large planned community development may have a strategy of aggressively increasing the number of lots being developed each year, with a maximum targeted number of lots if enough builders can be assembled. The planner needs to be appropriately skeptical of builders' plans for growth, but where a developer has demonstrated a track record of achieving targets, the projections warrant more consideration.

At CEI, Area Managers regularly meet with city officials and area developers to actively seek such information and provide information to the Planning group. This information is used to help adequately forecast load growth. Additionally, the Planning group regularly communicates with the CEI Customer Support group to determine what new construction is planned throughout the service territory.

Assess Capacity: This phase of capacity planning consists of the following activities:

- Perform Feeder Analysis on Expected Normal Load
- Identify Automatic Load Transfer Schemes
- Identify Voltage/Overload Problems
- Iterate for Long Range Planning

Perform Feeder Analysis on Normally Expected Load

Potential long term and short term capacity problems are identified when the forecasted load exceeds equipment or exit conductor ratings.

CEI uses Milsoft, the new FirstEnergy standard modeling tool. GIS provides system connectivity information to configure models built in Milsoft. GIS provides some load accumulation capacity for minor analyses, but Milsoft is the tool used to identify potential voltage regulation and conductor overload issues. There is some basic circuit tracing and load accumulation capability that is built into the GIS system which CEI has implemented

CEI planners perform distribution feeder analysis for each of its feeders in a timely manner, which means every year for some feeders and a longer interval for other feeders in areas of more stable to declining growth.

Identify Automatic Load Transfer Schemes

An automatic load transfer scheme allows a customer to have a separate feeder available to provide power immediately in case of an outage on the main circuit. If there is a loss of source for the primary circuit, there is an auto-swap to the alternative circuit and power is restored to the customer within approximately two seconds. When the main circuit once again has power, the main circuit closes, the alternative circuit opens, and the customer is served from the main circuit. In some cases, the transfer or restoration is manual.

CEI has many load transfer customers on the 36 kV and 11 kV subtransmission systems, consisting mainly of hospitals and office buildings whose load averages 3-5 MW. Since the 36kV system is designed in circuit pairs, to provide adequate capacity for a single contingency, the use of an automatic throw over between circuit pairs on the 36kV system does not overload the adjacent circuit.

Identify Voltage/Overload Problems.

In order for the next phase to be effective, however, it is important that the problems are properly documented during the assessment. If, for example, there are voltage support problems at the end of the line and no reading has been taken of line capacitance at crucial points, then the design options cannot be effectively evaluated.

In order for the various potential projects to be properly prioritized, it is necessary to have an estimate of the potential risk (in terms of the customers who might be lost and the time that might be involved in restoring service). It should be noted that having a small number of overloaded feeders in a given year, especially if it is a very hot summer (or cold winter, for winter peakers) is not in itself evidence of poor planning. In fact, at the distribution level, it would be overly conservative to install enough capacity so that, for example in CEI's case, all 1400 feeders were loaded less than their normal ratings.

Most equipment will continue to operate past its normal rating for a period of time. Indeed, it is common to speak of emergency ratings as those ratings above normal which equipment may be allowed to reach for limited periods of time. The penalty for overloading equipment is to suffer some long-term loss of life and to risk premature equipment failure. In distribution such failures may be no worse than when a tree hits a line, e.g., when a jumper or some other weak link in a line fails due to overheating, the line is interrupted just as if a tree had hit the line.

In reviewing CEI's loads across its distribution circuits (all voltages) we believe that CEI has takes a reasonable amount of risk in planning the load and capacity of its distribution feeders. Note that the higher-voltage feeders which serve more customers are less likely to be overloaded.

The average loading on all CEI feeders in 2006 was 65 percent, including those that were overloaded. The overloaded feeders represent the tail of a distribution whose mean is well below 100 percent. At the extreme tail of this distribution the feeders loaded over 110 percent of capacity are over 85 percent comprised of 4kV feeders. One would normally expect that forecast errors and moderate risk management would be able to avoid situations in which actual load exceeded normal rating by more than ten percent.

CEI's System Assessment and Future Outlook for 2007 is a thorough and comprehensive 20-page document that details the load and capacity in various locations, with specific ratings of specific transformers in specific substations. The analysis includes plans for future investments in capacity where needed, and reflects the kind of analysis that we have described above in terms of load projections. The resulting plan includes an appropriate degree of risk in terms of moderate loss of life on some equipment that is projected to be only slightly over its normal rating.

Iterate for Long-Range Planning

Distribution capacity planning is normally focused on the near term (i.e., the next peak season). This is due to the normally short lead time (normally less than a year) required to design and build a solution. Obviously, as the solution evolves from changing out line transformers to reconfiguring circuits, reconductoring, or adding feeders, transformers, and/or substations, the lead time required increases.

Sometimes a series of short-term solutions will turn out to be more expensive than one properly planned long-term solution, even after accounting for the time value of money and uncertainty. The distribution planner should, after planning for the near term, take a step back and look at the longer term scenario, including reviewing the forecast for long-term growth, anticipating long-term problems, and searching for long-term solutions that offer an alternative to a sequence of short-term fixes.

With this in mind, it is important to realize that it is not just the time value of money but also the value of information and reduction of risk that favors the series of short-term solutions. What if the forecast never materializes? Then the short-run solution may well suffice for the long run. If the short-run solution buys time to get a clearer picture of the future, it may not be wasted money, even if ultimately, with hindsight, it appears that a better long-run solution was available.

Design Options

This phase of capacity planning consists of two steps:

- Evaluate Alternative Design Options for Line and Substation Problems
- Coordinate with Other Areas and Transmission

The goal is to select the most cost-effective method for designing capacity improvements. Effective design planning should be consistent across the CEI territory while meeting the needs of each area.

Evaluate Alternative Design Options for Line and Substation Problems

Currently each planner develops the conceptual design for increasing capacity or enhancing the infrastructure within the planner's area. For projects with an estimated cost greater than a certain pre-established threshold, the planner must complete a more formal project funding request. This request should include an analysis of alternative approaches to the one the planner is requesting, as well as a discussion of the risk that would be involved in the potential deferral of this project.

All of the projects should be ranked to determine the budget that will be allocated for all such projects. Projects should then be approved for that year in descending order of their score. Planners should have at their disposal a template from which to plan for design alternatives for most capacity planning situations.

Coordinate with Other Areas and Transmission

The distribution planning group must communicate substation improvement plans with other parts of the company with particular attention to Transmission Planning and Protection. Increasing substation capacity will have a direct impact on the system wide transmission planning.

Additionally, the Distribution Planning group must periodically keep the dispatchers aware of contingency plans for losses of circuits or transformers. This will be especially beneficial in an emergency, as it is the dispatcher and not the distribution planner whose responsibility it is to give repair instructions to the line crew.

Another example of the benefit of system-wide coordination for certain projects is the savings from swapping substation transformers. As each planner puts forward proposals to upgrade transformer capacity in various parts of the system, it is advantageous to devise an overall strategy that is based on a 'domino' effect. For example, large transformers that are being replaced can be used as replacements for smaller transformers which are still in good condition, but which need more capacity. These, in turn, can be used to replace still smaller transformers, etc. CEI appears to be using this strategy to its advantage.

Manage Projects

This phase of capacity planning consists of revising the planned projects database, prioritizing and scheduling each project, designing the project, building the facilities and verifying the accuracy of all records. CEI's ability to perform these activities is addressed in Section 7.0.

Observations

CEI's practices in capacity planning and its investment in capacity upgrades align with standard industry practice. There are two instances, however, where CEI's standard practices follow one of two acceptable options, and we include the alternative option for informational purposes:

- Whereas some companies identify potential problems by normalizing the most recent load data to a 'normal' year before comparing it to capacity, CEI compares the un-normalized data to capacity to, and then assesses whether the problem would have existed in a normal year. Either method is acceptable.
- Some companies choose to have as a regular part of their planning process the comparison of projected loads and capacities on distribution transformers, and then to preventively replace only those where customer concerns have raised an issue. CEI, on the other hand, allows customer concerns to drive the replacement of distribution transformers and does not regularly compare distribution transformer capacity and load. The industry has long recognized that the projection of overload on a distribution transformer based on regular interval meter data is critically dependent on having a match between a monthly load profile by type of customer and the customers' actual monthly peak load, after accounting for diversity of load among the customers sharing the transformer. The result is that projection of overload is a very poor predictor of actual overload, to say nothing of actual failure, since distribution transformers are often capable of handling a considerable amount of overload prior to failure. Additionally, the time and expense required to replace a failed distribution transformer is not much different than that required to replace one proactively. So, it does not make sense to preventively replace, say, 1000 projected overloaded transformers in order to prevent the 5 or 10 that might actually fail on the hottest day. There have been, however, jurisdictions, e.g., Denver, where the volume of overloaded distribution transformers became so great due to significant usage pattern changes (adoption of air conditioning in areas that traditionally went through summer without it) that preventive replacement became worthwhile in order to avoid extended restoration times on hot days due to the large volume of outages. CEI's experience to date does not warrant such an approach.

5.4.2 Refurbishment and Replacement of Aging Infrastructure

As stated in Section 2.0, the overall condition of CEI's electric distribution system presents a significant challenge to CEI reaching top quartile performance in SAIFI and second quartile performance in CAIDI (i.e. the industry context for CEI's current reliability targets), particularly given the mandate to sustain this performance over a ten year period.

The underlying cause is two-fold:

- Inadequate funding for over a decade (commencing in the early-1990s), an occurrence that was common across the industry.
- Steadily decreasing staffing levels during this same time period amidst an increasingly challenging maintenance workload (due to increased inspection activities leading to higher levels of corrective maintenance and the inherent issues of aging equipment).

Recognizing a problem that has been 10-15 years in the making cannot be reversed overnight, the solution involves a number of longer term and related initiatives:

- Systematic and staged equipment/component refurbishment and replacement strategy, leveraging the initiatives addressed within the newly instituted Asset Management Plan.
- Integration of the Circuit Health Coordinators with the ESSS Inspection Program (providing an over-inspection role and coordinator in addressing high-priority reliability related inspection deficiencies/exceptions), and Reliability Engineers.
- Prioritization of evaluated workload with the concept of protecting the feeder backbone and addressing circuits with multiple customer interruptions.
- Recruiting and hiring of additional distribution line and substation personnel (in advance of the planned retirement of a rapidly aging workforce-Section 7.0), using this temporary increase in staffing to address the corrective maintenance backlog.

As CEI implements these recommendations and integrates them with the existing comprehensive system reliability improvement program, we need to be mindful that the current infrastructure though aged and in relatively poor material condition, is not the main cause for CEI missing its reliability targets. However, to get to the performance levels called for in the current agreement between the Staff and CEI and sustain that level of performance, these issues could become the controlling factors.

5.5 Summary of Recommendations

The following recommendations are submitted recognizing that many of them are more appropriately characterized as extensions of programs already in place. In most cases a more systematic approach (focused on the portions of circuits/lines that potentially impact the most customers) balanced with appropriate attention to customer satisfaction issues (e.g. elimination of multiple customer interruptions); CEI can realize a stepped improvement in SAIFI towards the 2009 goal of 1.0.

SI-1	Enhance tree-trimming program to address overhanging limbs and structurally weak trees on the feeder backbone

Discussion

In 2006, and comparably in 2004 and 2005, approximately 95,000 customer interruptions (CI) are attributable to the cause "Tree Non-Preventable". Of these, in 2006, 41,000 CI (more than 40 percent), are lockouts (presumably due to outages in the first zone from the circuit breaker to the first recloser, not counting taps), and 31,000 (more than 30 percent) are on the three-phase part of the line, which, while not always true backbone, is a reasonable proxy for purposes of analysis. Moreover, the lockouts are split approximately two-to-one (66 percent to 33 percent) between the 13kV and 4kV respectively, except that in 2006 the 13kV are unusually high, at 85 percent. Finally, the lockouts on the 13kV numbered 29 events on 27 circuits, while on the 4kV the lockouts numbered 19 on 17 circuits.

Therefore, it is reasonable to assume that if enhanced tree trimming were done on approximately 50 circuits (reviewing a list from 2004-2006 and using some judgment to select the best candidates) a substantial improvement could be achieved in future years. Experience elsewhere suggests a 50 percent improvement can be achieved by a program such as the one described above. This would yield approximately a 21,000 reduction in CI, or, in terms of SAIFI in 2008, a SAIFI impact of .026 interruptions for the average customer.

The cost of such a program would typically be about $20,000 per circuit, or $1 million, (recall that this would be done only on the first zone) and classified as an O&M expense. Periodic maintenance of this enhanced clearance would add some future cost, but the removal, where it happens, might partially offset that. Roughly, this program would cost $48 per CI avoided. This might be viewed as an appropriate 'first tier' of such a program. We highly recommend such an effort.

The second tier would be to address the outages on the rest of the backbone beyond the first zone. With the same effectiveness of 50 percent, this would yield an additional improvement of 15,000 CI, for an additional SAIFI impact of .020. The cost of the second tier would be considerably higher because it would be required on more circuits (approximately 100 make the list each year of circuits with lockouts on the backbone past the first zone) and most likely more mileage per circuit. A reasonable estimate of the additional cost for the second tier might be $3 million, making the unit cost approximately $200 per CI avoided. We believe this second-tier effort should be considered within the context of overall cost and benefit of achieving the reliability goals.

SI-2	Ensure lightning protection initiatives focus primarily on the feeder backbone, continuing to replace damaged arresters, but also consider adopting a more strategic approach by integrating FALLS and NLDN data with other contributing factors (e.g. type of construction, grounding, shared structures). NOTE: CEI is planning to replace lightning arresters at 3 substations in 2008.

<u>Discussion</u>

To gauge the impact of lightning protection, it will be useful to examine the lightning-caused CI in 2004-5, before the coding changed, on the theory that a comparable number of lightning-caused outages continued to occur in 2006, but were coded as line failure, equipment failure, or unknown. In those years, approximately 150,000 CI were due to lightning, again with a two-to-one ratio of 13kV to 4kV CI. Of these, only about 10 percent occurred as lockouts, i.e., in the first zone of the backbone, yielding a 15,000 CI target for a first-tier program. Only about 20 circuits would be involved. The cost of a properly focused program (more than just adding lightning arresters) would be approximately $50,000 per circuit, and might be expected to achieve at least a 50 percent reduction in lightning-caused first-zone CI's, i.e. a 7,500 CI reduction, for a SAIFI impact of .010, on an expenditure of $1 million, or $133 per CI avoided.

The second tier would target the two-thirds (2005) to four-fifths (2004) of lightning-caused CI that occurred on the three-phase line outside of the first zone, i.e. more or less the rest of the backbone. Thus, a program aimed at lightning protection of the backbone would focus conservatively on around 67 percent of the 150,000 CI per year, or a 100,000 CI target. Again, the split between 13kV and 4kV would be about two to one.

Under the same assumptions about program intensity, 50 percent effectiveness would yield a 50,000 CI reduction, or a SAIFI impact of .067. The expenditure would be much higher, however, since it would involve more than 150 circuits, with more mileage per circuit. Estimating $11.25 million, the second tier of backbone lightning protection would have a unit cost of $225 per CI.

SI-3	Apply a line/circuit inspection and repair prioritization scheme that focuses initially on the feeder backbone, then in areas where customers experience multiple outages (worst performing circuits and devices, and as a last priority, those areas that have lesser impact on system reliability.

Discussion

While the standard line inspection and repair program includes the backbone of each circuit, this program emphasizes the need to pay particular attention to the backbone of those circuits that continue to experience a high number of backbone outages, i.e., which typically interrupt a large number of customers.

The main focus would tend to be backbone outages due to three causes: equipment failure, line failure, and wind, but over the period 2004-2006 the coding of wind and lightning changed, making it somewhat more difficult to identify the targeted CI. In 2006, the total backbone CI (including lockouts and all three-phase outages as a proxy) for the four categories of equipment failure, line failure, wind and lightning was 380,000 CI. Subtracting the targeted lightning CI of 115k CI, we arrive at a reasonable 265,000 CI target for the line inspection and repair program. It is worth noting that the 380,000 CI can be identified as coming mainly from approximately 100-13kV circuits and 200-4kV circuits, and that the split of CI between 13kV and 4kV was closer to 1.5 to 1 rather than the 2-to-1 ratio shown in other analyses.

The effectiveness of a backbone inspection and repair program is dependent on prioritizing the repairs, and limiting them to the conditions most likely to give rise to a fault in the near future. Many fault-causing conditions are not readily apparent from inspection, being internal to the part that fails, e.g., conductor, splices, insulators, etc.

A reasonable estimate of effectiveness is that a program like this might achieve a 10 percent reduction in CI on the 300 or so circuits to which it might be applied. This translates to a 26,000 reduction in CI, or a SAIFI impact of .035.

The cost of this program can be viewed as an increment to the existing 5-year line inspection and repair program that is done for the entire circuit, and as such might only involve an additional $0.5 million per year of O&M expense. With the assumed 10 percent improvement in CI, this would imply a unit cost of $19 per CI avoided. As such, there is no compelling need to have multiple tiers for this program. The key to success will be, however, the focus on reducing backbone outages through identification and repair of fault-causing conditions on the circuits that have shown a tendency toward such. As well, our comments regarding the diligence with which the inspection and repair program identifies such conditions and resolves them are relevant here.

SI-4	Further sectionalize the 13.2kV feeder backbone (123 circuits with 500 or more customers that do not have reclosers installed are potential candidates), and review for possible sectionalizing, the 230-4kV circuits with more than 500 customers. NOTE: CEI will install 5 36kV SCADA controlled sectionalizers in 2007 and is planning to continue this initiative in 2008. NOTE: Memos were released to the design groups to install 14 reclosers, 61 sectionalizers, and 145 sets of fuses in 2007.

<u>Discussion</u>

Since sectionalizing the backbone targets the entire population of backbone outages, regardless of cause, it is appropriate to note that almost 700,000 CI per year were due to lockouts and three-phase outages in 2004 through 2006, with an approximately two-to-one ratio of 13kV CI to 4kV CI. Of those 700,000 CIs, lockouts normally run about 15 percent, but in 2006 they rose to almost 30 percent. Unlike the tree and lightning programs, however, the sectionalizing program is best divided into tiers not by whether it is first zone but by the number of backbone CI experienced on average per circuit, either because they had a high number of backbone events or because they had a high number of customers impacted. Once again, we find a two-to-one ratio of 13kV to 4kV opportunities. In fact, if we screen the circuits by how many lockout CI they have had in the period 2004-2006, we find that there are seventy-five 13kV circuits with more than 6,000 backbone CI in total over the three years (2,000 backbone CI per year), and thirty-eight 4kV circuits that meet that same criterion. An appropriate focus for a first-tier sectionalizing program would be approximately 100 circuits. The average annual number of CIs for those circuits represents a 350,000 CI target, averaging 3500 backbone CI per circuit per year.

Each switch applied to those circuits may be assumed to cost \$20,000 when fully installed, assuming that what is often used as the sectionalizing device is a bank of three single-phase sectionalizers. One hundred such devices could be installed for a cost of \$2 million.

The effectiveness in reducing CI, as applied to the target figure, would depend on the configuration of each circuit, which is a level of detail beyond the scope of this study. If, for example, the circuit had no reclosers on it at all, which is true of many of the CEI circuits, then it might be assumed that two switches might be installed, one at the midpoint and one at a tie-point at the end of the backbone. Such an installation might be expected to reduce lockout CI on that circuit by 50 percent, or 25 percent per switch. This figure is often cited in studies of sectionalizing effectiveness when no reclosers exist. At the same time, the use of three single-phase sectionalizers instead of one, affords the possibility that only one-third of the customers might be interrupted by a downstream fault behind the sectionalizing device, raising the effectiveness of a mid-point sectionalizer from 25 percent to 41 percent.

In practice, there are many complications that prevent developing a clear scenario, including the presence of existing reclosers (which complicates the computation of effectiveness, since it limits the amount of line exposure that the recloser effectively controls), the difficulty in finding a single tie-point that could carry the whole back end of the circuit, etc. If, for example, a circuit already has three reclosers on it, then achieving even a 25 percent reduction may require an additional sectionalizing device for each zone that has a high number of feeder backbone CIs.

For purposes of estimation of program impact, we assume that the installation of an additional sectionalizing device on a circuit would reduce the backbone CI for that circuit by 20 percent, which, for this population of 100 circuits would yield a 70,000 CI reduction, for a SAIFI impact of .093 interruptions for the average customer, at a unit cost of $29 per CI (or $2 million) avoided.

The second tier of such a program might address another 100 circuits (costing another $2 million), whose average annual backbone CI per year might comprise a 176,000 CI target, which, with a 20 percent effectiveness, would yield a 35,000 CI reduction, for a SAIFI impact of .047, at a unit cost of $57 per CI avoided. Since the current work plan calls for completion of this second tier in May 2009, the 2009 impact should be adjusted accordingly (to .033).

SI-5	Identify opportunities to replace existing three-phase reclosers with single-phase reclosers (should be considered on a case-by-case basis, depending on the needs of the customer, and the impact to a major commercial or industrial customer that requires three-phase power). NOTE: CEI will replace 4 three-phase reclosers with single phase closers in 2007.

Discussion

As our discussion of SI-5 makes clear, a mid-point recloser that would normally mitigate 25 percent of interruptions in the zone which it bisects, i.e., the two zones which it created when it was installed can be credited with mitigating a higher percentage if it is a bank of single-phase reclosers instead of a single three-phase recloser. In each case, due consideration of all three-phase customers in the downstream zone must be given, and, any limit the application of this principle somewhat. Also, the effectiveness of a program of retro-fitting banks of single-phase reclosers will be dependent on the frequency with which faults occur on only one phase.

In the extremes, if there were no single-phase faults, the retrofit would be useless, and if they were all single-phase faults, the retrofit would increase the sectionalizing device's effectiveness from 25 percent to 42 percent. A reasonable assumption would be an increase from 25 percent to 33 percent (which would be appropriate if half of the outages were single-phase), or an 8 percent improvement in sectionalizing effectiveness. The target of that improvement would be all the backbone outages in that zone.

If we approach this analysis from a basis of the average zone to which it might be applied, we see that if a zone covering 1000 customers had two outages per year, then without the recloser there would have been 2,000 CI, and the recloser can be credited with saving 25 percent, or 500 CI. If the recloser were a bank of single-phase reclosers, it might be expected to save 33 percent, or 660 CI, for a net improvement of 160 CI. The cost of the retrofit would be approximately $20,000, so the unit cost of the program is $125 per CI avoided.

At present CEI has identified only four locations in 2007 where it saw an opportunity to employ this tactic. This would amount to a cost of $80,000 and an improvement of 640 CI reductions, or a virtually negligible SAIFI impact. Without further knowledge of the individual circuits and customers involved, we can only suggest that the method be employed in those instances in which the economics warrant it, e.g., where there a large number of single-phase backbone faults and where customer considerations allow it.

SI-6	Analyze application of instant trip and timed re-close on a circuit-by-circuit basis, considering the nature of the circuit and its customers, the history of success with instant trip/timed re-close on the circuit, and any damage that might be done if the instant trip is not set.

Discussion

This recommendation is oriented to further study of this issue, with particular emphasis on keeping the instant trip on if the study indicates it is often successful in clearing faults. Since at present, CEI only has a limited number of circuits without the instant trip, this is not expected to improve SAIFI much, but merely prevent it from deteriorating.

SI-7	Inspect, maintain, test and repair or replace (as test results indicate) the 4kV exit cable, particularly given the age and condition of much of the buried cable. NOTE: CEI is planning to replace selected substation feeder exit cables

Discussion

In the period 2004-2006, CEI's 4kV circuits experienced approximately 30,000 CI from outages on three-phase cable in conduit (excluding dig-ins). While not all of this is exit cable as such, by far most of it is, and the issue is much the same for other cable in conduit (road crossings, etc.). In 2006, the 30,000 CI arose mainly from 100 outages on 50 circuits. The worst 30 circuits over the period averaged 17,000 CI per year on 30 circuits, including 6 circuits from the Harrington substation, 5 from Lakewood, 4 from Jersey and 3 from Gladstone. While we did not request detailed data on those particular exit cables, we estimate that the typical job of exit cable replacement might involve an average of 1500 feet of cable at a cost of $30 per foot, or $45,000 per circuit. Replacement of the worst 30 circuits would therefore cost $1.35 million. The effectiveness of the replacement might ordinarily be assumed to be almost 100 percent, since the new cable should be less likely to fail, but in reality the effectiveness, as applied to the targeted CI, is dependent on how likely it is that other exit cables, not selected, may fail instead of the ones targeted, thus causing the same level of exit cable customer interruptions.

That is why it is important to use diagnostic equipment to test the exit cable, in order to ensure that only those cables that are prone to failure will be replaced. In fact, using the VLF testing, the cable will fault, requiring at least a repair, i.e., replacement of the faulted section or splice, if not replacement of the whole length.

If it can be assumed that by targeting the worst cable for replacement, 50 percent effectiveness can be achieved, then a reduction of 8,500 CI might be achieved, for a SAIFI impact of .01, at a unit cost of $159 per CI avoided.

A second tier might address the next 30 4kV circuits. In the period 2004-2006, these circuits generated an annual average of 7,000 CI from exit cable faults, and so would afford about 40 percent of the opportunity of the first tier for the same cost, i.e., a reduction of 3,400 CI, for a SAIFI impact of .005, and a unit cost of $397 per CI avoided. Because of the economics, and the existence of other programs that could help CEI achieve its goals, we would not expect the second tier of this program to be implemented.

SI-8	Develop a worst-CEMI program, not necessarily to substantially improve reliability, but to ensure a proper balance with Customer Satisfaction (Key off of Worst Performing Devices Report analyzing all equipment that experiences 2 failures in a month or 3 in a quarter).

Discussion

This program is targeted at improving customer satisfaction by addressing the outliers of performance rather than by affecting the average, hence it is expected to have only minimal impact on SAIFI.

SI-9	Replace failure-prone URD cable to avoid customer complaints and save repair costs (minimal impact on improving overall SAIFI). NOTE: CEI will replace approximately 300,000 feet of URD cable in 2007 and is planning to replace an additional 200,000 feet in 2008.

Discussion

This program is targeted at improving customer satisfaction by addressing the outliers of performance rather than by affecting the average, hence it is expected to have only minimal impact on SAIFI.

SI-10	Integrate the Circuit Health Coordinators with the ESSS Inspection Program to provide an over-inspection role, as well as a coordinator to address high-priority reliability-related inspection deficiencies/exceptions.

Discussion

This recommendation is designed to ensure that the implementation of the Circuit Health Coordinators does not negatively impact the effectiveness of the existing ESSS Inspection Program. As such, it is more important for avoiding SAIFI problems that would otherwise occur than for achieving a specific improvement in SAIFI.

Non-Distribution Circuit Recommendations

Consistent with the Outage History and Cause Analysis (Section 3.0), the Service Interruption Assessment was focused on the programs and processes related to the

Distribution Lines/Circuits. However, CEI still needs to maintain an appropriate amount of attention on the substations and subtransmission lines, as well. Significant improvement was noted in over the past 5 years in both areas, and should continue as CEI remains committed to those measures that contributed to this improvement. Recommended actions SI-11 and SI-12 highlight the importance of maintaining that focus, and document the investments that have been made in 2007 (and are planned for 2008) to continue and/or maintain this improvement:

SI-11	Continue to address the operability of switches on the subtransmission system NOTE: CEI will replace 9 36kV older-style problematic switches in both 2007and 2008. NOTE: CEI is also going to prioritize the need and rebuild, as necessary, additional 36kV circuits.

Discussion

The impact of continuing to replace problem switches will be to offset the long-run deterioration of this equipment. Since this is the primary action related to the improvement in subtransmission SAIFI, continuance of this practice is highly recommended.

SI-12	Continue to replace circuit breakers and relays at the substations. NOTE: CEI will be performing the following projects in 2007: Upgrade 11-13kV Feeder Breakers at 3 distribution stations; Install 5-three-phase reclosers as interim feeder protection; and Replace slow reset CO-5 relays at 5 substations. NOTE: CEI is planning to perform the following projects in 2008: 13kV Feeder Breaker upgrades with SCADA control; Replace additional slow reset CO-5 relays; Replace 2-36kV Feeder Breakers at Northfield Substation; Replace Circuit Switchers at 4 substations NOTE: CEI is also planning to replace substation batteries at 20 substations in 2007 and 10 substations in 2008.

Discussion

The impact of replacing circuit breakers and relays at selected substations will be to offset the long-run deterioration of this equipment. The impact on the next few years, then, is likely to be not significant, but it would accumulate to a significant effect if ignored for five or more years.

6.0 Service Restoration Assessment

6.1 Purpose, Scope, and Approach

The purpose of this section of the report is to explain our analysis of the Company's service restoration process. As noted in our Reliability Assessment Framework (Section 4.0), one element of improved reliability is related to mitigating or eliminating service interruptions ("outages") as presented in Section 5; the second key element is related to the timely and effective restoration of service after an interruption has occurred.

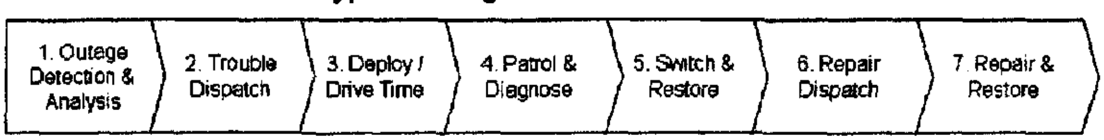
Utilities across the United States are increasingly and appropriately subjected to regulatory and public scrutiny about their service restoration performance, especially in the context of storms and public emergencies (as measured by CAIDI). In many cases, post-storm assessments have been done by third parties at the request of the utility and its regulator. These assessments and specific responses by utilities have resulted in valuable lessons for the industry and the key concepts described below are used to compare CEI's current policies and practices and results.

6.2 Service Restoration Process

The service (or outage) restoration process is perhaps the most complicated operational process at any electric utility. It requires coordination and communication across substantially all key functions of the distribution business and is implemented in a time-critical environment (often in extreme weather conditions and non-standard working hours). It requires an extraordinary focus on safety while key participants are making innumerable real-time decisions to satisfy to the operational, engineering, and customer related demands.

These extreme and complex performance requirements have led utilities to take a highly process-focused approach to managing and monitoring these critical reliability-related activities. While no two utilities implement these processes in precisely the same manner, they all follow a general flow as outlined in Figure 6-1 below:

Figure 6-1
Typical Outage Restoration Process



A summary level definition of these process steps are as follows:

1. Outage Detection & Analysis – This process step begins with the first call, usually from a customer but sometimes from police/fire agencies or the public at large when they see a wire down, street lights out, etc. In more advanced systems they may come from sensing devices. The key activity here is to recognize that multiple calls may have a common root cause and so must be grouped into a 'case' or 'outage', with each outage being the grouping of one or more customers who are electrically 'behind' the same isolating device, be it a fuse, recloser, circuit breaker, substation, bus, or transmission line. While an outage management system may suggest, based on a model of how customers are connected to the system, which customer calls roll up to which common device, ultimately a human must confirm or change that assignment through a process that involves outage analysis. On a clear day, for example,

it is unlikely that customers on two different but nearby taps might call in within fifteen minutes of each other because of two separate outages, so the automated algorithm will typically assume that they are related to a common point of failure upstream of both of them. On a stormy day, however, it is possible that two such outages are distinct. Ultimately, the case will be determined by the crews' onsite observation, but in the meantime a dispatcher or a case analyst working with the dispatcher must make an assignment of calls to cases or outages.

2. Trouble Dispatch – Once the dispatcher has identified a "case" or outage, a troubleshooter can be assigned and sent ("dispatched") to the likely location of the fault, or at least to the location of the isolating device. In fact, as soon as the first call comes in, it may be assumed to be a 'single no-light', i.e., an outage involving only one customer, and a troubleshooter may be assigned to start moving in that direction. As more calls come in and the case is analyzed, the location of the isolating device may change from the premise of the original call to the common isolating device (fuse, recloser, etc.) of the group of calls that make up the case. One of the key issues during this stage of the process is whether a troubleshooter is available, or will be soon, to go to the call, and if not, whether some other first response resource can be mobilized to fulfill the role. This will depend, of course, on the dispatcher's sense of whether the outage is large enough or would be delayed long enough to warrant mobilization of a different resource. In the worst case, e.g., in a major storm, outages may queue up at this stage of the process and await the next available resource, all while time passes and customer minutes of interruption accumulate.

3. Deploy / Drive Time – Inevitably, one step of the process must be deploying the troubleshooter to the location. Depending on the size of the territory, the time of day, and where available resources are currently deployed, the travel time may be short or long. In addition, one may group into this category the time it takes to mobilize a resource, i.e., if the dispatcher has decided to call out a resource from off duty, the case may be considered as assigned (and so no longer awaiting dispatch) but the troubleshooter to which it is assigned is not actually en route to the location but is still being mobilized.

4. Patrol & Diagnose – Once the troubleshooter arrives at the location of the isolating device, and maybe even while on the way, depending on the optimal route of travel, the troubleshooter will look for evidence of a fault – broken limbs or fallen trees, an auto accident or dig-in, etc. This is called patrolling and it has two functions – one is for public safety, to be sure that there is no wire down anywhere that could make it unsafe to re-energize the line and the other is to find the fault that caused the isolating device to operate. Many times, the offending root cause will have cleared itself, as in when a branch singes its leaves to the point that they no longer can make contact with the line, or when an animal is no longer in a position to bridge the gap between conductor and ground (or another conductor), etc. In such instances, the troubleshooter will be able to re-energize the line (replace the fuse, re-set the recloser or breaker) without experiencing another fault, but the line should be patrolled first to ensure that such an action can be taken safely.

5. Switch & Restore – If the troubleshooter finds the location of the fault-causing damage, and it is clear that it is a permanent fault that will not be cleared until

the damage to facilities is repaired, then the next action is to look for ways to accomplish partial restoration, i.e., restoring at least some, and hopefully most, of the customers. This is done by first isolating the faulted section of line and then re-energizing the un-faulted sections. Isolating the faulted section may be done by operating two disconnect switches on the line – which are placed at various points along the line for just such purposes, or by 'cutting in the clear', i.e., cutting conductor on each side of the faulted section, with the intention of splicing the line back once the repair is done. In some cases, if the permanent repair is straightforward and can be accomplished quickly, or if the number of customers affected is small and not easily restored by other means, then this switch and restore step will be skipped and the process moves straight to repair and restore.

6. Repair Dispatch – Once the faulted section is isolated, it is usually necessary to get a full line crew out to do the permanent repair. A lone troubleshooter can only do minor line repair. The process of getting a line crew requires going through the dispatch function for that resource, which may be another person. Line crews typically scheduled to perform new construction, road moves, or planned replacement/upgrade work, and are likely to be busy with another job when they are called out to do restoration repair work. The dispatcher for those resources makes the judgment call about which crew can most easily be interrupted to be sent to do the outage repair work. Note that strictly speaking, there is another step in the process at this point, which is travel time for the repair crew, but this is usually grouped into the repair time, because the repair time is likely to be significant (compared to the relatively quick step of switching and restoration).
7. Repair & Restore – Once the repair crew arrives at the site of the damage, the permanent repair can be made and the last group of customers restored. Depending on the extent of the damage, this can be a matter of many hours.

Within the context of this process, there are certainly opportunities to isolate each step and identify opportunities for improving service restoration (i.e. reduce customer minutes of interruption). And the company should, as a matter of course, perform a detailed challenge of each process step to identify these opportunities and incorporate any findings into its overall reliability improvement plan. For the purpose of this assessment, we will take a cross-sectional view of these steps by first, looking at service restoration performance from an overall perspective; and then, assess the company's performance in three domains: Mobilization, Work Flow and Communication.

6.3 Service Restoration Performance Overview

Before addressing the company's practices, processes, and performance with respect to service restoration, it is appropriate to review the company's CAIDI performance over the past 5 years to assess the overall trend towards achieving the 2009 target of 95.0. Figure 6-2 shows a stepped improvement in CAIDI since the 2002/2003 period, as CEI closed the gap by 50 percent (to approximately 125.0 minutes). This amount of improvement reflects an obvious management focus on improving practices and processes around service restoration. Equally impressive (and daunting), is the amount of improvement still required to reach (and sustain) the 2009 target.

Figure 6-2
CEI CAIDI Performance – Non-Storm without Transmission

	2002	2003	2004	2005	2006
Outages	7,533	6,759	6,615	8,661	8,246
CMI	110,796,914	156,335,383	111,309,573	141,040,088	112,382,533
Customers Interrupted	717,517	932,418	846,068	1,234,999	875,992
CAIDI	154.42	167.67	131.57	114.20	128.29

Consistent with the approach developed in Section 3.0, the main focus of this assessment (in terms of identifying opportunities for leveraged improvement) will be with the distribution feeders (with particular emphasis on the backbone). Therefore, a view of CAIDI performance from a district perspective is appropriate; looking primarily at distribution line CAIDI (i.e. less substation and subtransmission CAIDI).

Figure 6-3
CEI Distribution Line CAIDI Performance

Reported District	2002	2003	2004	2005	2006
Ashtabula	140.84	254.06	171.74	150.01	191.84
Brooklyn	212.73	211.76	180.39	175.48	136.74
Concord	147.86	206.78	187.05	170.43	121.35
Euclid					
Mayfield	173.98	177.55	181.18	164.43	143.55
Miles	183.65	202.57	183.61	155.31	170.00
Solon	213.10	255.54	172.28	123.62	134.79
Strongsville	171.14	174.50	188.14	163.01	150.04
West Lake	156.30	173.65	148.17	200.38	153.70
Total	171.98	208.41	176.66	166.83	148.65

NOTE: Euclid represents a new line district started just prior to 2007.

With the exception of the Ashtabula line district, one of the more rural areas in the system, the overall trend in CAIDI performance from 2002 to 2006 is positive (the West Lake and Miles line districts have oscillated over the five year period, with negligible, if any improvement). Ashtabula represents almost half of the territory. CEI is in the process of establishing another line district (Claridon Twp) (planned in-service date of 2009) to help alleviate the challenges inherent to such a large area and established the Euclid line district in 2007 to alleviate some of the challenges associated with the Miles line district.

Viewing Figure 6-4, there is no other obvious correlation between the CAIDI performance trend from 2002 through 2006 and the demographics defining each district. This would suggest that the solution, therefore, lies in further improving the overall processes and practices, much of which is already in progress (as indicated in the performance improvement to date).

Figure 6-4
CEI District Demographic Information

District	Customers		Circuits				
	Number	PCNT	CKT Miles	PCNT	OH Miles	UG Miles	PCNT OH
Ashtabula	62,136	8%	1,932	16%	1,638	294	85%
Brooklyn	135,553	18%	1,436	12%	981	456	68%
Concord	67,618	9%	1,953	16%	1,028	926	53%
Euclid	53,302	7%	530	4%	382	147	72%
Mayfield	95,667	13%	1,275	11%	947	329	74%
Miles	121,680	16%	1,318	11%	784	534	60%
Solon	28,491	4%	920	8%	382	530	42%
Strongsville	104,473	14%	1,407	12%	664	743	47%
Westlake	78,106	11%	1,179	10%	566	612	48%
TOTAL	747,026		11,949		7,371	4,578	62%

6.4 Service Restoration Performance Assessment

In assessing the company's performance in service restoration, this assessment will compare CEI's practices and processes against industry "leading" practices from three related perspectives:

- Mobilization (with an emphasis on being proactive in terms of planning and establishing contingencies),
- Workflow (focusing on partial restoration and follow through for permanent restoration), and
- Communication (both externally with the customers and internally in terms of timely reporting of customer restoration).

6.4.1 Mobilization

Regarding mobilization, some of the major insights of leading utilities in this area involve recognizing the considerable benefit that can accrue to early mobilization. Although the benefit of early and effective mobilization must be weighed against the cost of mobilizing resources for a 'false alarm' (i.e., a storm that either does not hit as forecast or does less damage than that forecasted), the pendulum is swinging toward ensuring that enough resources are at hand early in the storm because of the importance of getting the mainline feeders back up quickly.

Until the feeders are returned to service, dispatchers are operating "in the dark" with incomplete information. With feeders down it is difficult to know which taps have also suffered damage. Based on the dynamics around a 'nested outage', the only ways to prevent extended restoration times after a major storm are:

- Conducting field-based assessments
- Initiating special action by the dispatcher
- Prompting customers with IVR to confirm when their service is restored

The remedy is a sufficient complement of feeder troubleshooting and repair crews early in the storm. The alternative, or more appropriately a complementary activity, is to have sufficient damage assessors deployed to the affected areas and find evidence of damage on dead lines. This will only be partially successful, since in some cases the trees have knocked down poles and/or line and it will be obvious; but in other cases the fault is less apparent and will require electrical connectivity to fully isolate and detect the fault.

Early mobilization itself is dependent on two key activities: 1.) weather forecasting that can be translated into resource requirements, and 2.) the prearrangement of additional resources available on a contingent basis. Weather and resource forecasting tends to be well developed for hurricanes but it is often not very well developed for smaller storms, with heavy dependence on dispatcher experience. The number of variables involved in accurately forecasting the impact of a given storm can easily overwhelm the experience-based forecasting capability of dispatchers and/or storm managers, leading them to fall into a 'wait and see what the damage is' approach, which can take far too long in the critical early stages of post-storm restoration. The industry is working on developing better tools to assist in such instances.

The second element - being able to garner sufficient resources quickly - involves three different layers of resource support:

- The company's own resources, both repair crews and also second-job resources for wire watching, damage assessment, and logistical support,
- The company's contractors and those of other companies that can spare them, and
- Mutual assistance resources (again, mainly repair crews but in some cases support personnel as well) from other utilities that can reach the affected area in a timely manner.

The first layer, the company's own resources, would seem to be straightforward. However, it can be complicated by work rules and the company's ability to call out resources from home or other assignments. Also, the second-job capability that support staff can provide can only be effective if they are trained and drilled in how to assist properly in the effort.

The second and third layers depend on good relationships and communication with contractors and nearby utilities. Such relationships must be worked out in advance in some detail. All utilities, of course, have some experience at using mutual assistance, but even within that body of experience it is recognized that some do it better than others, with the right processes to enable foreign crews to be effective in one's own restoration efforts. Some find it necessary to break up their own crews and assign them one each to the foreign crews to allow them to read maps, draw materials, record restoration, etc. Another well-known factor is that companies which are currently using contractors for construction or maintenance may find it easier to tap the resources of the contracting company in an emergency.

In general, CEI complies with these concepts, particularly using servicemen (line leader shift) and support staff (ranging from simple logistics to performing damage assessments), and establishing clear policies/procedures to govern the transition of shifts. There are, however, a number of areas where the company can further reduce customer minutes of interruption; these topics are explored in the following subsections.

Storm Pre-Mobilization

Pre-mobilization with respect to storms offers a potentially high leverage point in eliminating customer minutes of interruption. Figures 6-5 and 6-6 (previously presented in Section 3.0), provide a historical perspective of the correlation of effective wind speed, outages and average outage duration.

Figure 6-5
CEI Storm Model

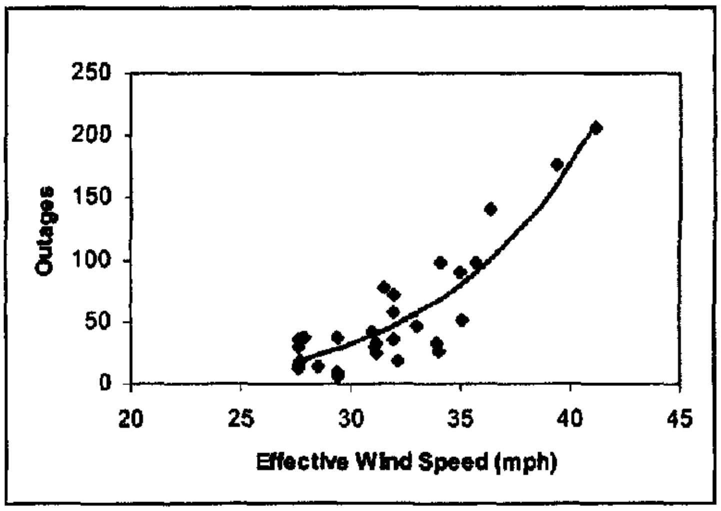
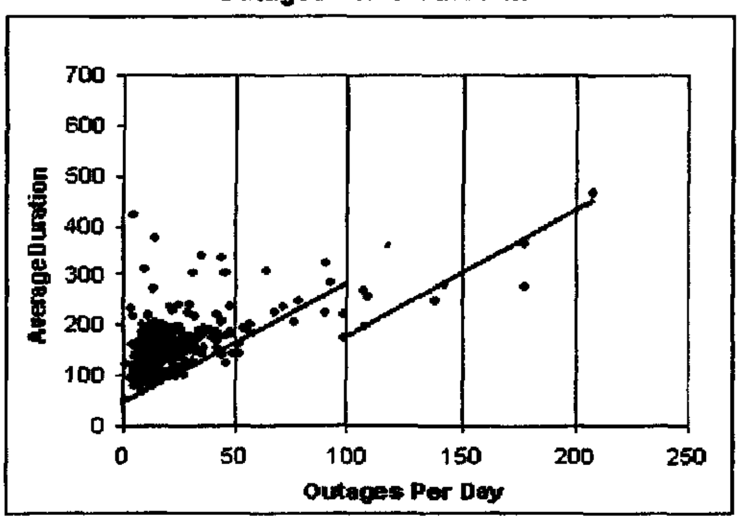


Figure 6-6
Outages Drive Duration



As one would expect, Figure 6-5 shows that effective wind speed certainly has had an impact on the number of outages that have occurred during any one storm event (in fact, the relationship has been exponential with a rapid increase in the number of outages as effective wind speeds have exceeded 30-35 miles per hour). Further, the number of outages has had a definite effect on average outage duration, with an apparent stepped improvement at 100 outages per day (most likely due to a change in system restoration staffing in anticipation of a storm), and at about the same point that effective wind speed hits the 30-35 miles per hour threshold. Similar correlations are likely to exist with other weather-related variables (e.g. heat storms, lightning).

Given these interrelationships, CEI could benefit by integrating all of these factors into a common methodology to introduce empirical data into the decision around pre-mobilizing staff (in anticipation of a storm); not in place of the intuitive and experiential approach that is already working, but as an enhancement to it. There is obviously a cost-benefit relationship that needs to be explored (the cost of pre-mobilization against the anticipated reduction in average outage duration).

CEI Energy Delivery Management would certainly benefit from better understanding the predicted correlation of key weather factors to number of outages per day and the level of incremental staffing necessary to further reduce total customer minutes of interruption.

First Responder Program

CEI has implemented a program whereby certain employees equipped with pagers are put into a database that matches the employees' typical work locations (and home location) with the nearest substations. When the dispatcher gets an alarm that indicates an outage (or warning) condition at one of those substations, the dispatcher can page all those who are matched to that substation with a request that they check with the dispatcher and, if needed, go immediately to the substation to observe the situation.

This program effectively expands the substation troubleshooter staffing by providing "extra eyes and ears" (and, with the proper training, helping hands as well) in those critical situations in which a portion of the substation, e.g., an entire transformer bank feeding many circuits, is either de-energized or alarmed.

It is worth noting that the typical SCADA at a substation involves a limited number of alarms that while informative may not be conclusive in what they tell about the situation. For this reason, it is very useful to have whoever is nearest to the substation get there as soon as possible – even if that person might not be qualified to do switching or some other aspect of restoration or prevention.

If the responding staff member is trained and qualified, and the work rules allow it, the first responder may be able to initiate action that restores customers. Clearly, substation outages can involve large numbers of customers – even more than lockouts of a single feeder, so anything that can be done to reduce the restoration time for such outages could have an impact on overall CAIDI.

In our interviews, we heard substation supervisors endorse the value of the First Responder program (even encouraging more effective participation). We similarly feel that reinforcement of this program can only help CEI's CAIDI while having minimal negative impact, if any, on costs or productivity of the workers involved. This is a First Energy practice that many others in the industry would do well to emulate.

Call Outs

A key factor in achieving improvement in CAIDI is improving the time it takes to mobilize a crew that must be called out from being off duty. All utilities struggle with this challenge and various changes in processes, work rules, and technology have been utilized to address it, including such things as using more sophisticated paging or cell phone systems to maximize response, changing work rules that require that callout be done in order of seniority, as well as how and when the utility is allowed to move down the list and the minimum block of time for which a callout is credited, and even allowing crews to drive trucks to and from home after duty.

CEI's response rates presented in Figures 6-7 and 6-8 are typical for the industry with the overhead lines and substation response rates at 57 and 53 percent, respectively. Top quartile performance is in the range of 70-75 percent. However, the impact on overall CAIDI in closing a 13 to 17 percent gap would be minor and should not be a major focal point in achieving the 2009 targets. That being said, call-out response is certainly a measure of organizational alignment around the issue, and should be used more as a barometer of CEI's effectiveness in establishing this alignment, than as a point for focused improvement.

Figure 6-7
Overhead Lines Call-Out Response

Month	PAGER CREW					NON-PAGER CREW				
	Total Calls Made	Yes	No	No Answer	PCNT	Total Calls Made	Yes	No	No Answer	PCNT
JAN	26	21	2	3	81%	245	131	70	44	53%
FEB	49	44	4	1	90%	379	149	68	162	39%
MAR	14	11	1	2	79%	132	95	16	21	72%
APR	39	37	0	2	95%	291	146	104	41	50%
MAY	43	43	0	0	100%	374	204	145	25	55%
JUN	35	34	0	1	97%	273	169	60	44	62%
TOTAL	206	190	7	9	92%	1694	894	463	337	53%

TOTAL CALLS	1900
YES	1084
NO	470
NO ANSWER	346
PERCENT	57%

Figure 6-8
Substation Call-Out Response

Area	Calls	Responded	PCNT
East	335	168	50%
West	80	56	70%
TOTAL	415	222	53%

Alternate Shift

For the last five years utilities have been experimenting with the use of an alternate shift to better match the availability of crews with the need for repair work in minor storms. The standard utility shift is related to the standard 'day shift' in all of industry, with a shift toward the morning as is typical in many construction-related industries (the typical utility day shift is 7AM to 3PM or 7:30AM to 3:30PM).

Statistically, it can be shown that particularly in the non-winter seasons thunderstorms that develop from normal diurnal convective activity are more likely to occur in the mid- to late-afternoon or early evening. Therefore, in many instances the storms hit just as utility construction crews have quit for the day. When the storms can be anticipated, the utility can make an effort to 'hold over' some crews from the day shift (on an overtime basis) and this is another initiative in itself on which we will comment below. Also, crews can be 'called out' by telephoning or paging them with a message to contact the dispatcher for an extra duty. A less costly and more certain measure is to arrange for some of the crews to work an alternate shift. Of course, the 'evening shift' that some of the troubleshooters work is well suited to handle such storms, but if the damage involves significant line work, then full overhead line crews will be needed to make the repairs.

It is possible to have construction crews on an evening shift, but it is not ideal because the need for them does not typically extend to the end of such a shift, e.g., 11PM, and more importantly such a shift, on a regular, daily basis, tends to conflict with worker productivity, visibility, safety, and customer satisfaction (due to noise and intrusive activity in the evening hours).

The alternative that many utilities have developed is to have a shift that begins around 11AM or noon and extends to 7PM or 8PM. Particularly if this is used in the daylight savings period, the concerns about working at night are allayed and the shift does not seem as unnatural, and may even be preferable to some workers. The typical practice is to have only a handful of crews switch to this shift, because for various reasons the standard construction shift remains the ideal for most. However, the shift of even a few crews can noticeably improve the ability to respond to late-afternoon storms as shown in Figure 6-9 below.

Figure 6-9
Outage Duration by Hour of the Day

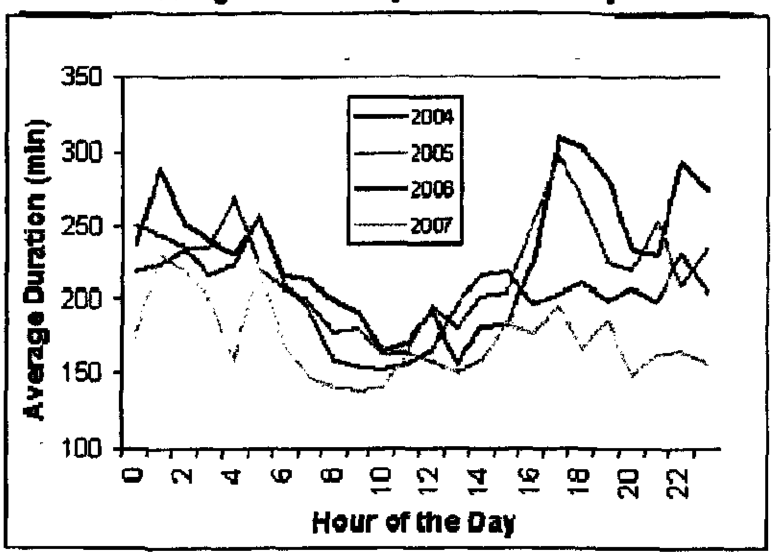


Figure 6-9 above shows that the use of alternate shift was first introduced in 2004, but used rather intermittently. As CEI approached 2006, this practice became more wide-spread, the results of which are evident on the profile of outage duration by hour of the day. The 2006 and 2007 (year-to-date) profiles show no real differentiation during the 4PM to 8PM time frames (in contrast to the marked improvement over 2004 and 2005). These trends (as well as those experienced by similarly configured utilities) point to the need for the Company to remain committed to this leading industry practice.

6.4.2 Workflow

In terms of workflow, our assessment will focus on methods of returning as many customers as possible to service during the initial stages of the switching and restoration phase of the outage restoration process. There are some issues in the area of dispatching, not from a practices perspective, but because of the recent influx of inexperienced dispatchers and the challenge of retaining staff in these key positions once they have been trained (addressed in Section 7.0).

Partial Restoration

Partial restoration refers to the practice of switching and even cutting around faulted sections of a line to be able to restore at least part of the customers early on, leaving a smaller group of customers to have to wait until final repairs are made. This practice has long been a part of utility outage restoration efforts and it has also long been resisted. To be fair, it is appropriate to resist using the method when a final repair could be made relatively quickly and it is always a judgment call as to whether it is better to use the available resources to complete the final repair or to divert them temporarily to make other partial restorations.

Utilities regularly report that line crews prefer to do the final repair and try to convince the dispatcher that they will be able to do it quickly. The risk is that unforeseen delays may cause a large number of customers to remain unconnected when partial restoration might have been done expeditiously for a large majority of the customers.

CEI has confirmed that this typical tension does exist and has committed itself to reinforce its position on partial restoration. We would emphasize that this is particularly relevant when restoring feeder backbones:

- When the backbone is out, all of the customers on that feeder are out, which on the 13kV circuits is often over 1,000 customers.
- Until the feeder backbone is restored, it is generally not possible to discover, except by detailed patrol, that additional locations or taps require repair in order to effect restoration.
- Except in the most rural areas, the system is designed to allow feeder backbones to be 'back-fed' through normally open ties to other feeders. This allows the utility to isolate the faulted part of the feeder and close the appropriate ties to re-energize a large number of customers on the circuit.

The system, in fact, is designed with redundant capacity for precisely the purpose of handling contingent capacity for partial restoration. In many cases the 'partial' restoration can be almost a complete restoration (e.g. in instances where only a single span or a few spans need be isolated in order to clear the fault, the rest of the feeder can be restored as fast as it takes to throw disconnect switches or even physically cut the conductor to isolate the fault and then throw the tie switches to restore). This is in part why installation of more automatic reclosers is recommended – they rapidly isolate a faulted zone and re-energize the rest of the feeder, allowing the remaining restoration effort to concentrate on a zone that is more compact, significantly decreasing the miles required to drive to close each normally open tie.

Therefore, we recommend that CEI continue to reinforce the practice of partial restoration, especially on feeder backbones and large taps, even when that may involve 'cutting' perfectly good conductor in order to isolate faulted spans, so that crews can then 'run' to restore the remaining parts of the circuit.

<u>Split and Hit</u>

Another method of partial restoration is termed 'split and hit'. This is normally applied to underground residential distribution (URD) lines, but could conceivably be used on overhead lines where the density of tree cover or dark of night prevents the troubleshooter from being able to easily locate the fault (though in the latter case extra precaution is required to ensure public safety when re-energizing the line). The challenge being addressed with this approach revolves around locating the faulted section of cable. This applies typically among the many sections of underground primary that extend from the riser through each of the pad-mounted transformers to the normally open point of the typical URD half-loop. Once the faulted section is located, the pad-mounts on each end of only that section are opened, the elbows are disconnected and parked, and the pad-mount at the normally open point is opened, its elbows un-parked and connected, thus 'back-feeding' the half-loop up to the faulted section.

The blown riser can then be replaced, re-energizing the front part of the half-loop. At that point, all customers are restored, and will remain so until the cable faults in a different section. This is comparable, in concept, to 'switching around' an overhead faulted section, i.e., a workaround that isolates the faulted section and restores service at both ends of the faulted section through switching. In the meantime, it is important to repair or replace the faulted section of cable in a reasonable time, so that it can be used in a similar fashion to complete a half-loop should another section fail.

At times it is appropriate to call out a special underground crew, supplied with test equipment and trained to locate the faulted section. This approach will likely cause some delay in effecting the restoration. The more expeditious alternative is to have the lone troubleshooter, the first to arrive at the scene, use the 'split and hit' method:

- The troubleshooter should go to a pad-mount halfway between the riser and the normally open point on the half-loop (in order to 'split' the half-loop into a quarter-loop). Since the riser fuse is blown, this transformer will be de-energized.
- The troubleshooter should then disconnect the cable elbow on the blown riser side, then go back to the riser pole and, using a hot stick, replace the fuse ('hitting' the quarter-loop by re-energizing it).
- If the faulted section of cable happens to be on the re-energized side, the fuse will blow immediately (which is why the troubleshooter must take appropriate precautions such as looking away, etc. – this is no different than when the same is done on an overhead tap that has been patrolled and found to have no obvious faults).
- If the fuse holds, power has been restored to that quarter-loop, and even if it blows, the troubleshooter can then restore the other quarter-loop by going back to the split point, disconnecting the faulted side, and back-feeding the un-faulted side from the normally open point, since cable faults almost always occur on only one section of cable in a half-loop.

- At this point, the troubleshooter will apply the same method to the remaining faulted quarter-section, restoring even more customers, or, if there are other outages that need troubleshooter attention, and the number of customers out on this tap is now relatively small, the troubleshooter will call for the test crew to complete the job on the remaining quarter-section.

In the meantime, the number of customers interrupted has been cut in half, often in less time than it would take for the underground crew to be mobilized and travel to the site. FirstEnergy has used the split and hit method effectively for years in other regions. It is an industry leading practice and we recommend that CEI continue its use.

6.4.3 Communication

Regarding communications, a recurrent theme in post-storm assessments is the need to do a better job of keeping everyone informed about the current state of the restoration efforts and to establish a culture of continuous improvement through forums geared to constructive sharing of experiences and circumstances, both positive and negative. This includes customers, employees, contractors, foreign crews, communities, emergency agencies, regulators, media, and other public officials. Moreover, the best way for people to get information is to know in advance what information is available and where. Through advanced planning and drills, communities can come to better understand the role of various different community functions in restoration. In a phrase, "plan the work, work the plan," is the approach that will instill the most confidence and dispel the confusion and competition for resources that comes from a more ad hoc approach.

Implementing all of these leading practices requires an organizational focus on achieving desired performance levels in storms through planning and follow-up on process changes and learning what works best. It is no longer acceptable to merely claim that infrequent storms are extraordinary events that cannot be measured in terms of performance. On the contrary, the increasing demands and expectations of the public for community continuity even in the face of emergencies requires a planned approach to what might seem to be an unforeseeable event.

In assessing CEI's performance in the area of communication, the following observations and recommendations are provided:

- CEI has devoted a portion of their website to provide customers with timely emergency and storm restoration information. Our view is that this website is well-designed and implemented, and serves as an effective supplement to the more traditional communication methods.
- CEI's IVR is effective in managing the customer interaction and is cited as one of the factors in their experienced improvement in customer satisfaction.
- Recognizing that the "moment of truth" occurs at the scene of action (and often occurs between the servicemen/line crews and the customer(s)), CEI provides training on how to properly interact with the customer.
- CEI as instituted the 4-Hour Outage Review Process to address the causes, remedies, and "lessons learned" in outages that exceed 4 hours in duration. This appears to be highly effective in that it deals objectively with the issues and keeps the focus on shortening outage duration.

- Following the lead of other FirstEnergy companies, CEI has instituted an Outage Page, ensuring a sense of urgency and supervisory awareness of all outages involving feeder lockouts, and those affecting more than 100 customers (the notifications occur at the start of an outage event).
- In an effort to improve the coordination and communication between Regional Dispatch and the field, CEI has instituted a cross-familiarization training program between the dispatchers and the servicemen. The dispatchers receive field familiarization training and the servicemen receive similar training in the RDO/Call Center.
- The Monthly Reliability Meeting is among the best we have experienced, in terms of relevance, clarity, and action-orientation. The annual goals are articulated, progress against them assessed, and specific challenges from the previous month vetted; all of this information is presented with a focus on supporting a continuous learning environment.

6.5 Summary of Recommendations

The following specific recommendations are submitted recognizing that many of the suggested improvement initiatives are already integrated into the company's practices and processes (as evidenced by CEI's improvement over the past five years). Within each practice and process there is the opportunity to apply some fine tuning to further reduce customer minutes of interruption.

SR-1	Systematize the process of determining when to mobilize staff in anticipation of a storm.

<u>Discussion</u>

The company effectively applies experience, intuition and weather information to proactively apply supplemental resources prior to storms. Figure 6-6 shows that the impact of this combined experiential and intuitive approach equates to mobilizing for storms that lead to over 100 outages. The opportunity involves "sharpening the pencil" a bit, and determining where the cost-benefit trade-off occurs by applying the correlation of number of outages and key weather variables into the analysis in a more quantifiable and predictive manner.

From Figure 6-6 it is evident that mobilizing for storms can save an average of approximately 100 minutes per outage. It is also clear that there are approximately ten days per year that have outages per day in the range of 50 to 100, say an average of 75. These ten storms then generate 750 outages per year. CEI's typical average number of customers interrupted per outage is approximately 100, so these medium-outage days represent 75,000 customer interruptions. Now, a 100-minute saving on each would generate a potential savings of approximately 7,500,000 CMI (customer minutes of interruption, the numerator of SAIDI and CAIDI). If CEI is able to meet its SAIFI target of 1.0, a savings of 7,500,000 CMI would have a favorable CAIDI impact of 10.0 minutes. As a conservative estimate, we believe CEI can achieve 60 percent, or 6.0 minutes of CAIDI improvement from this method.

The cost of the additional mobilization could be estimated in terms of having approximately 45 additional resources available for a few hours in each of the ten storms (roughly, one 2-person line crew for each of the 9 shops, 1 hazard person for each, and a troubleshooter/switcher pair for each). Of course, if the timing is right, there would be no incremental cost for these resources, since they were needed anyway, so the real cost is when they are mobilized unnecessarily. If this were half the time, say 3 hours on average, we might expect a cost of approximately $10,000 per storm, or $100,000 per year. The unit cost can be viewed in terms of 100 CMI (approximately the duration of a typical interruption for one customer) as $2.22 per 100 CMI. Clearly, this is a program that CEI should heartily endorse.

A 'second tier' of implementation of SR-1 would be to apply the same logic to the larger storms as well, i.e., the storms which, though still minor enough to not be excludable, involve 100 to 200 outages per day. From Figure 6-6 it is clear that CEI already 'shifts gears' when this level of storm is experienced, but the sheer volume of outages on those days still leaves the average duration above 200 minutes (yet better, by 100 minutes, than what it would be without a changed paradigm). If the timing and level of mobilization for the larger (yet still not excludable) storms could be increased still further, we believe that a further improvement in CAIDI for those days could be achieved, with a quite reasonable estimate being an average of 50 minutes, e.g., reducing a 300-minute CAIDI to 250 minutes. If this could be done for the approximately 10 days that fall into the category of 100 to 200 outages per day, for which the average number of customers interrupted is 10,000 to 20,000, and the average CMI is 2 to 8 million CMI for each storm, the effort could achieve an additional reduction of 7,500,000 CMI, for an additional CAIDI impact of 10.0 minutes. We believe that a conservative estimate of what CEI might be able to achieve might be 5 minutes. The cost of this additional mobilization would probably be comparable to that of the first tier, because we are only looking to improve the average CAIDI in each storm by 50 minutes.

SR-2	Fully implement partial restoration ("hit and run" for overhead lines; "split and hit" for URD cable) when initially servicing customer outages.

<u>Discussion</u>

These methods require continual reinforcement as there is a natural tendency on the part of linemen (and with every good intention) to want to restore all customers in a given area to service as soon as possible. Consistent with the philosophy of focusing on the feeder backbone, these approaches focus on reducing the total number of customer interruption minutes by restoring as many customers as possible as soon as possible.

In terms of quantifying the potential impact of partial restoration on customer minutes of interruption, one approach would be to suggest that in the typical backbone outage, there are approximately 300 customers interrupted (500 for a lockout, 250 for a backbone outage past the first zone) for approximately 120 minutes, and that through partial restoration 200 of these might be restored in two-thirds the normal time, and the rest in 150 percent of the normal time. This would imply that the outage would accumulate 30,000 CMI instead of 36,000 CMI, for a reduction of 6,000 CMI per outage. If this could be done for half of the 2000 backbone outages that typically occur, the savings would be 6,000,000 CMI, or a favorable CAIDI impact of 8 minutes.

The cost involves having enough troubleshooters, switchers (substation mechanics), and experienced dispatchers to organize and carry out the switching (and perhaps some cutting) involved in partial restoration. The incremental cost of three additional full-time troubleshooters and three additional switchers, for example, would be approximately

$0.5 million, which, if it were adequate to achieve the effect, would represent a unit cost of $16.66 per 100 CMI.

Partial restoration is a practice that has been embraced as an accepted practice within CEI for quite a while. However, our sense during the interviews is that CEI is not achieving the full potential that this opportunity presents; in fact, our estimate is that they are achieving 50 percent of the CMI savings (3,000,000 CMI). That would equate to an opportunity to improve CAIDI by 4 minutes at a cost of $125,000.

SR-3	Fully implement use of the alternate shift (based on documented evidence of reduced outage durations at the critical transition time between normal shifts)

Discussion

There is likely to be ongoing pressure to reconsider the alternate shift (particularly in future discussions with the bargaining unit). The company should continue to evaluate the impact of the alternate shift (using a similar methodology applied in this assessment) to demonstrate its effectiveness and justify continuing the approach. If anything, the analysis should look for opportunities to expand this approach (district by district and at differing time frames).

The impact on CAIDI of having the alternate shift may be gauged by the difference noted above in the average duration by time of day (although this may also be due in part to better mobilization for late-afternoon storms). The difference is approximately100 minutes for three hours (5-7PM), and those three hours on average comprise 20 percent of the CMI for the year, so one could estimate a favorable CAIDI impact of 20 minutes (part of which may be attributable, as we suggested, to other initiatives as well). CEI is already doing this (and has likely captured the majority of this CAIDI benefit within their 2006 numbers), but our sense from the interviews is that its implementation has only recently been applied across all of the districts. We believe this will appear in future years as an additional 2 minutes (10 percent) of CAIDI improvement.

In addition, CEI plans to provide additional supervision to the crews that work on the nights and weekends. It is believed that this additional supervision will result in a marked improvement in CAIDI for outages that occur during those times. In 2006, the CAIDI for the hours outside of the main shift was 30 minutes higher than for the main shift. Even a 10 percent improvement in that gap would yield 3 minutes of improvement for those outages, which make up more than 60 percent of all customer interruptions. Hence, we estimate an additional 2 minutes of improvement in overall CAIDI due to this effort, which we group under this recommendation as being similar to the alternate shift.

SR-4	Continue the recruiting and training of new dispatchers (in advance of the anticipated wave of retirees) and consider ways to make the position more attractive to the more traditional source of supply (e.g. experienced linemen).

Discussion

Section 7.0 addresses the near-term shortfall of experienced dispatchers in the wake of an aging staff. During the interviews, it became apparent that the most obvious source of supply (experienced linemen) is not vying for the position. Apparently, the economics combined with the high-pressure nature of the job serve as a deterrent to what would appear to be an optimal source of supply. Otherwise, the company is likely to experience some impact to customer minutes as the lesser-experienced dispatchers (even though properly supervised) provide direction to the field in basic switching and restoration activities.

As noted above in SR-2, the training of dispatchers can have an impact on the success of partial restoration, since all switching must be coordinated through dispatch.

SR-5	Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007)

Discussion

Clearly, one of the key factors in achieving faster restoration is reducing the drive time between jobs (or between the current location of the crews and their next job). Recognizing this, CEI opened a new line shop in Euclid to relieve the travel time from Miles and Mayfield. The proposed new shop in Claridon Township would provide a much-needed location in the southern part of Concord and Ashtabula districts (and even to some extent the eastern part of Solon district). It is not unreasonable to assume that these new locations will reduce travel time on many jobs by a half-hour or more. Weighting such jobs in with the total time spent on all jobs, we estimate a 5 minute improvement in CAIDI for the eastern districts, which themselves make up slightly more than half of all CMI. This in turn can be expected to have a favorable CAIDI impact of 2.5 minutes. However, since this service center is not expected to open until the end of 2009, its impact on CAIDI in 2009 is nil.

The opening of the Euclid district in 2007, however, may be expected to have a similar, though lesser impact on the future years, including 2008 and 2009. Because the distances involved are much shorter, we estimate only a 1.0 minute improvement in CAIDI from this initiative.

SR-6	Reevaluate level of staffing with respect to outage response

Discussion

The current level of staffing appears adequate in terms of overall performance with respect to service restoration. However, as CEI implements the recommendations of this assessment, there are a number of items that may change the dynamics; namely:

- Increased sectionalizing, while improving SAIFI, will likely have a negative impact on CAIDI.
- Fewer interruptions within an outage could have the same impact as an increase in staff (i.e. lack of demand equates to added capacity).
- Added line districts that will decrease travel time and provide the potential for more efficiency among the staff.
- An accelerated staffing plan that will create a temporary increase in staff to be applied to storm restoration activities (as appropriate).

The purpose of this recommendation is to draw CEI management attention to the fact that some of the variables and assumptions that tend to drive service restoration performance have changed (the impacts of which are somewhat indeterminate); and it would be prudent to keep a close eye on the key performance indicators to proactively make adjustments should they be deemed appropriate.

SI-1 to SI-7	Impact of CI Reduction on CMI

Discussion

In addition to the improvements in CAIDI noted above, which are all due to implementation of recommendations SR1-6, we want to acknowledge that the implementation of the SAIFI-related recommendations will have a favorable side benefit of improving CAIDI because of the reduction in outages caused by vegetation, lightning, and pole-top equipment failures. The combined effect of the outage-reducing initiatives can be expected to eliminate more than 200 outages each year, or about .55 per day, which, based on the slope of the lines in Figure 6-6, can be expected to reduce the average CAIDI by a little over 1 minute. In addition, the sectionalizing can be expected to reduce patrol time significantly on backbone outages, for which the average CAIDI was 115 minutes in 2006. It is estimated that patrol time is almost one quarter of the total CAIDI for such jobs, and that sectionalizing could cut it in half, eliminating 14 minutes from CAIDI for those outages, and therefore 10 minutes from overall CAIDI. Since, however, the sectionalizing will only be done to a select group of approximately 200 circuits; we would estimate that the improved CAIDI from sectionalizing would amount to 4 minutes of improvement to total CAIDI. Therefore, the impact on CAIDI from the various SAIFI improvement initiatives total 5 minutes.

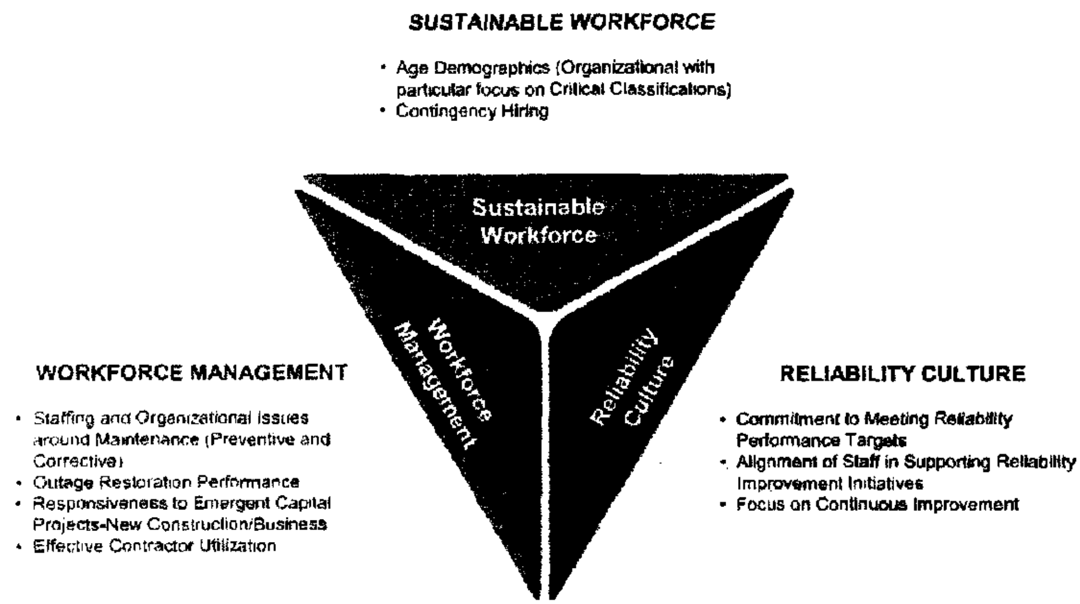
7.0 Organization and Staffing Assessment

7.1 Purpose, Scope, and Approach

The purpose of this section is to analyze CEI's organizational structure and staffing with a perspective on how these elements of the Company affect electric system reliability and offer the potential to sustain improvement in reliability. Our analysis is not a staffing study per se (e.g. it is not designed to be a comprehensive work level or span-of-control analysis); however, it is designed to assess the organization, its functions, and its staffing levels and their impact on SAIFI and especially CAIDI.

We have framed our assessment of CEI's organization and staffing by evaluating them from 3 perspectives as presented in Figure 7-1 below:

Figure 7-1
Elements of the Organization and Staffing Assessment



The elements of our review can be summarized as follows:

- **Sustainable Workforce:** This portion of the assessment addresses CEI's ability to maintain its staffing levels and knowledge base at a level sufficient for the company to carry out its mission with respect to system reliability. Key reliability-related functional areas of the Company are reviewed with respect to the age demographics, experience level, and current staff mobilization and training processes of the workforce.
- **Workforce Management:** This portion of the assessment focuses on the company's ability to keep pace with its inspection and maintenance requirements, to improve outage response, and to execute the capital spending plan (specifically New Business and reliability/capacity projects). It also includes recommendations on how to better utilize contractors.

- **Reliability Culture:** This portion of the assessment focuses on the Company's effort to ensure that its sustainable and well-managed workforce is aligned (at all levels) to the Company's imperative to improve overall system reliability. Through our numerous interviews (over 40 interviews with 26 individuals were conducted over a 3 month period) we were able to gain a sense of this level of alignment and we will provide some suggestions on how to maintain and enhance it amidst the ongoing business changes such as CEI's *transformation to an* Asset Management orientation.

The majority of the insights and recommendations contained within this section will have little if any immediate impact on CEI meeting its 2009 Reliability Performance Targets. However, the issues raised and concepts discussed in this section are vital to the Company's ability to achieve the objective of 10 years of sustained performance.

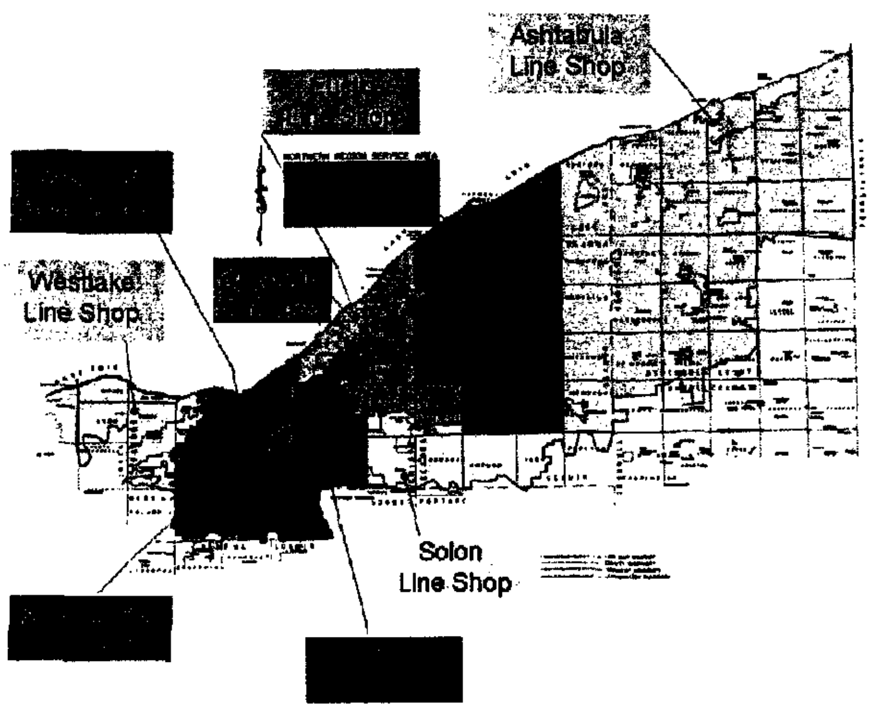
7.2 Overview of the CEI Organization Structure

The CEI electric system serves approximately 750,000 customers in a service territory that spans across Northeast Ohio and is referred to within the company as the *Northern Region* of FirstEnergy's Ohio-based electric system. The company's electric distribution network covers over 1,700 square miles of service territory and is composed of approximately 14,000 circuit miles (distribution and subtransmission); these circuits include 8,500 overhead circuit miles and 5,500 underground circuit miles.

The company headquarters are located in the south-central part of the territory in Brecksville and it manages the electric system by decomposing the service territory into 9 geographic areas referred to as *districts*. These district offices are informally referred to within the company as *line shops* or *garages.*

Figure 7-2 below provides a geographic overview of the company's service territory and its 9 major district headquarters.

Figure 7-2
CEI Service Territory



The growth conditions of the company's service territory reflect the general economic conditions of Northeast Ohio; overall, it has seen substantially no net growth in the past 5 years. Certain areas of the company are experiencing modest growth; others are in fact experiencing negative growth patterns. Figure 7-3 below summarizes the scope and compound average (customer) growth rate (CAGR) of each of the company's district operations.

Figure 7-3
Customer Count and Growth Rate by District

District	No. of Customers	2002-2006 CAGR
Ashtabula	62,136	1.2%
Brooklyn	135,553	-1.0%
Concord	67,618	0.8%
Euclid	53,302	-1.9%
Mayfield	95,667	0.4%
Miles	121,680	-1.4%
Solon	28,491	0.1%
Strongsville	104,473	0.5%
Westlake	78,106	0.6%
TOTAL	747,026	-0.2%

Each district manages its area of the network through a company and contractor workforce that is assigned from the district's line shop and is responsible for over 1000 circuit miles of electric distribution system (except Euclid) Each district has a composition of both underground (UG) and overhead (OH) circuits. Figure 7-4 below highlights the infrastructure composition of each of the districts.

Figure 7-4
Electric Infrastructure by District

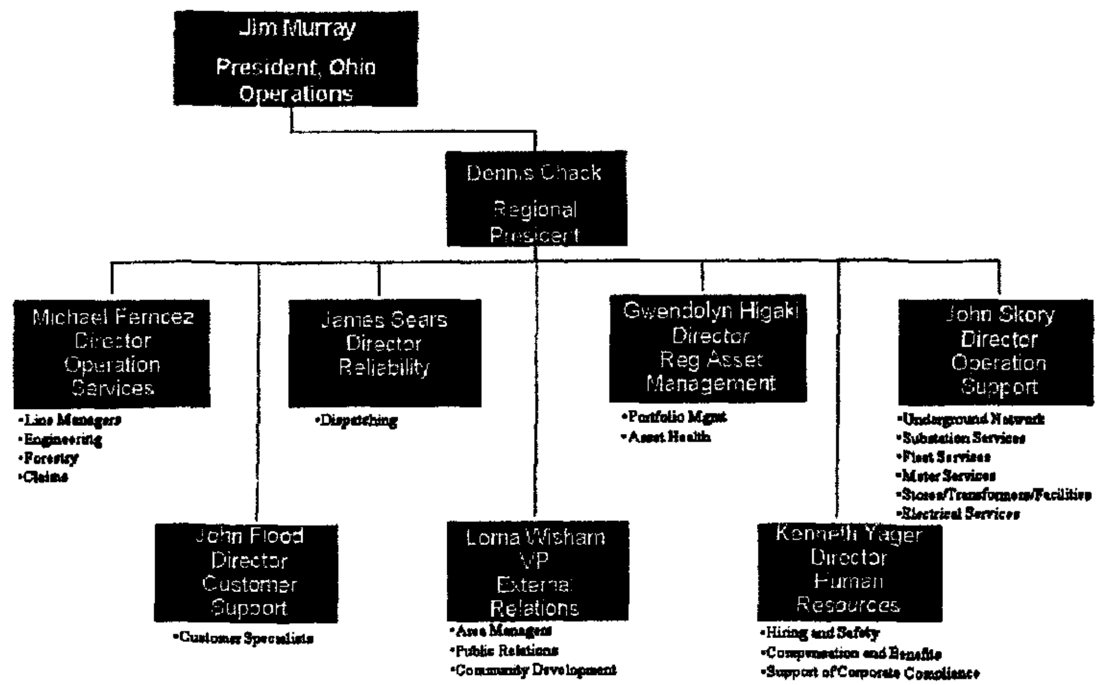
District	Customers		Circuits				
	Number	PCNT	CKT Miles	PCNT	OH Miles	UG Miles	PCNT OH
Ashtabula	62,136	8%	1,932	16%	1,638	294	85%
Brooklyn	135,553	18%	1,436	12%	981	456	68%
Concord	67,618	9%	1,953	16%	1,028	926	53%
Euclid	53,302	7%	530	4%	382	147	72%
Mayfield	95,667	13%	1,275	11%	947	329	74%
Miles	121,680	16%	1,318	11%	784	534	60%
Solon	28,491	4%	920	8%	382	530	42%
Strongsville	104,473	14%	1,407	12%	664	743	47%
Westlake	78,106	11%	1,179	10%	566	612	48%
TOTAL	747,026		11,949		7,371	4,578	62%

The company organizes its workforce into broad functions; these functions include:

- **Operation Services** - manages the primary *lines workforce* and is organized by the district structure noted above.
- **Operations Support** - has the primary responsibility for the substation and underground network work groups and is managed through an *East* and *West* organizational structure for substations, while one underground network group covers the entire CEI territory.
- ***Other Planning and Management Functions*** – includes Asset Management, Human Resources, External Relations, and Customer Support.

Figure 7-5 below presents a high-level overview of the CEI organization.

Figure 7-5
Current CEI Organization Structure



The current organization structure embodies several recent and noteworthy changes:

- The Director of Reliability role and function was recently established to provide a local leadership role and focal point for driving improvement in overall system reliability.
- The Director of Regional Asset Management was defined to be the leading operating company representative responsible for locally implementing the FirstEnergy Asset Management strategy. It is a pivotal role in the Company's ability to meet the long-term objective of 10-years' of sustained reliability performance at the agreed upon targets. It will be responsible for such elements as planning and managing the portfolio of capital projects (including staged and systematic refurbishment of aging

infrastructure), strategic staffing model, and integrated capital and O&M spend optimization.

7.3 Assessment of Organization and Staffing

The following subsections of this Section of the report summarize our assessment of the three distinct perspectives of CEI's organization and staffing as they relate to overall system reliability. Restating, the three perspectives are:

- Sustainable Workforce
- Workforce Management
- Reliability Culture

7.3.1 Sustainable Workforce

In assessing the ability of CEI to maintain a sustainable workforce, our scope spanned across the Operations Services, Operations Support, and Reliability Departments. Figure 7-6 below identifies the critical departments, functions, and positions (also known as job families) that will define the focus of this analysis.

Figure 7-6
Critical Staffing Categories

Department	Function	Positions
Reliability	Regional Dispatching	Regional Dispatcher
Operations Services	Distribution Line	Line Leader Shift Lineworker Leader Distribution Lineworker
	Engineering Services	Engineer Distribution Specialist
Operations Support	Substation	Relay Tester Electrician Leader
	UG Network	Underground Electrician Leader Shift Underground Electrician Leader Underground Electrician

Within each of these Departments/Functions/Positions there are specific challenges with respect to maintaining a sustainable workforce. From a overall perspective, the predominant issues facing the Company include a rapidly aging workforce, few succession options with respect to leadership and management positions (a topic that the company actively monitors and manages), and a resource-constrained pipeline in terms of recruiting and hiring replacement staff to address planned retirements. Figures 7-7 and 7-8 below further illustrate these points.

Figure 7-7
CEI Employees by Age and Function

Function	Current Age					Total
	<30	30-39	40-49	50-59	>59	
Substation	13	7	29	60	11	120
Distribution Line	42	60	96	152	14	364
Underground Network	1	11	16	25	0	53
Engineering Services	6	10	20	33	3	72
Regional Dispatching	5	6	13	10	0	34
TOTAL	67	94	174	280	28	643
PERCENTAGE	10.4%	14.6%	27.1%	43.5%	4.4%	

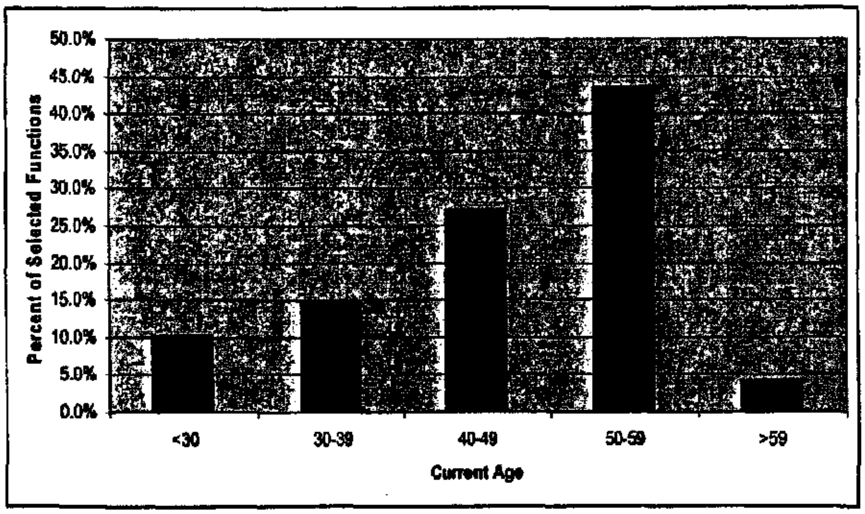


Figure 7-7 above notes that almost 48 percent of all employees within these functions are over 50 years of age (totaling 308 staff) and are likely to retire within the next 10+ years.

Figure 7-8
Leadership/Management by Age and Function

Position	Current Age					Total
	<30	30-39	40-49	50-59	>59	
Substation	0	0	8	7	1	16
Distribution Line	0	3	14	19	0	36
UG Network	0	0	3	3	0	6
Engineering Services	0	0	2	6	0	8
Regional Dispatching	0	0	0	1	1	2
TOTAL	0	3	27	36	2	68
PERCENT	0.0%	4.4%	39.7%	52.9%	2.9%	100.0%

Over 55 percent (38 of 68, as shown in Figure 7-8) of the current Leadership and Management staff in these targeted areas is also likely to retire within the next 10+ years. The pipeline for future Leaders and Managers is typically composed of the Non-Managers (included in Figure 7-7) that currently range in age from 30-39); this pipeline is clearly constrained.

Notwithstanding outside recruiting and hiring, over 40 percent of the current 30-39 year old cohort (38 of 94 members) will need to develop into leaders and managers (a particularly daunting percentage as the normal percentages of leaders/managers to staff are more in the range of 10-20 percent). This will occur at the same time when 48 percent (308 staff) of technical staff will also be retiring thereby placing additional demands on the remaining staff. This will place an enormous burden on this 30-39 year old cohort and particularly on its leaders.

This situation is not unique to CEI or to First Energy. It is typical for virtually all electric utilities in North America and Western Europe. Generally speaking, industry-wide trends to reduce O&M and capital spending during the 1990s led to hiring freezes and this has resulted in an abnormally distributed work force in terms of age demographics (very few employees were added in the 1985-2000 era). Utilities (including CEI) are now increasing their hiring efforts and simultaneously face new competition for resources from other technical fields and industries.

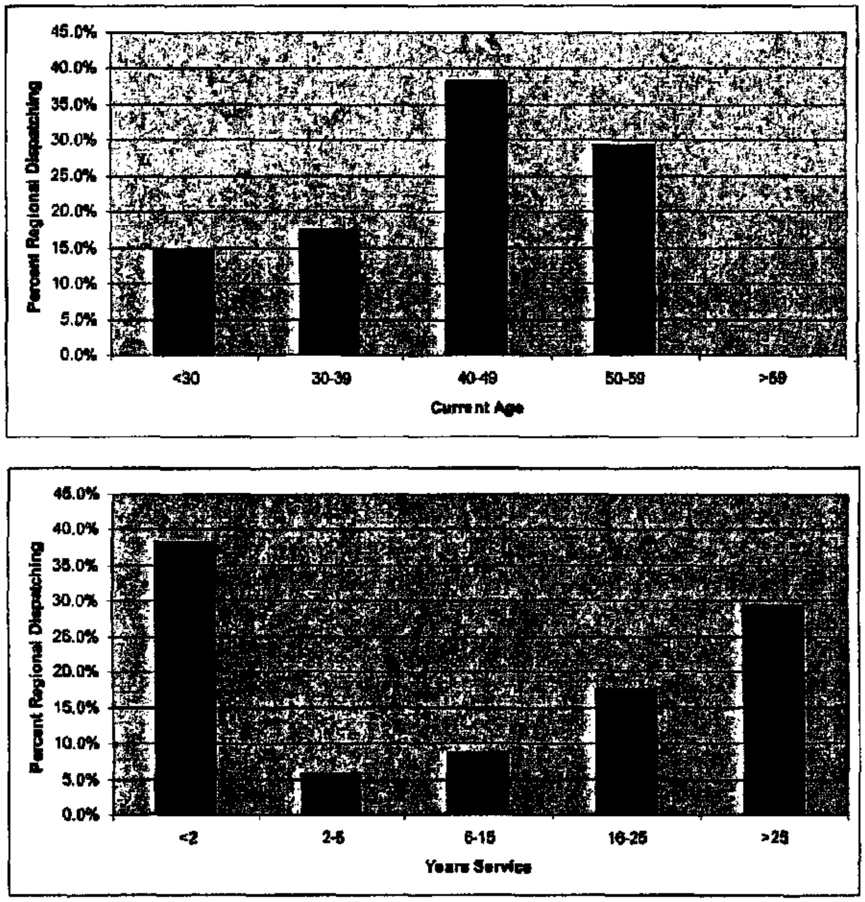
To mitigate these effects FirstEnergy has taken a number of steps to address this challenge, most notably the PSI Program. The PSI program could certainly be categorized as a "Leading Practices" approach to recruiting, training, and assimilating entry level employees. The Company's key challenge is the pace at which this staffing shortfall, a decade in the making, can be addressed. This is particularly acute given the other realities of budget and headcount constraints and general availability of labor. Unfortunately, there is no shortcut to developing future leaders and managers. This will require an aggressive outside recruiting effort, coupled with a well-conceived leadership and management development program.

Though the issues presented as part of the high level view apply within each of the Departments/Functions listed in Figure 7-6, a look at the more critical positions offers other insights as outlined below.

Reliability

Figure 7-9 below exhibits the scale of the staffing challenge facing CEI for Regional Dispatchers. The company will need an aggressive approach to addressing the anticipated departure of almost 30 percent of the Regional Dispatchers over the next 10+ years. In so doing, CEI will likely experience some challenges in sustaining its level of performance in the timely restoration of service since more that 35 percent of the current staff has less than 2 years experience (it is easy to observe that from changing staff demographics in the next few years more than ½ of the Regional Dispatchers will have less than 5 years of experience).

Figure 7-9
Regional Dispatching Staff by Age and Experience



In conjunction with continuing to work the recruiting pipeline to replace retiring regional dispatchers, CEI should also explore ways to encourage longevity among the existing dispatching staff. During interviews it was apparent that CEI needs to consider ways to make this key position more attractive financially to high performing employees.

Operations Services

The profiles for the Distribution Line and Engineering Services functions are presented in Figures 7-10 and 7-11 below and they are not significantly different from the patterns previously reviewed. Over 46 percent of the Distribution Line employees will retire over the next 10+ years, as will 50 percent of the Engineering Services staff. Of particular note is the projected loss (and thus the required replacement) of 124 Distribution Linemen and 21 Distribution Specialists.

Figure 7-10
Distribution Line Staff by Age Category

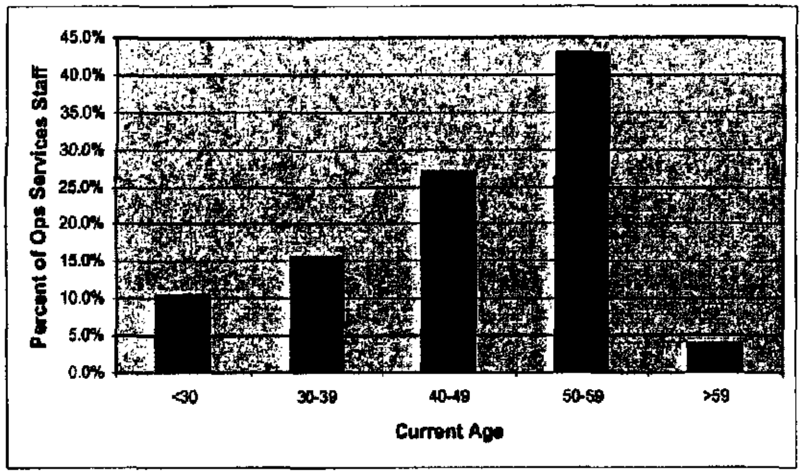
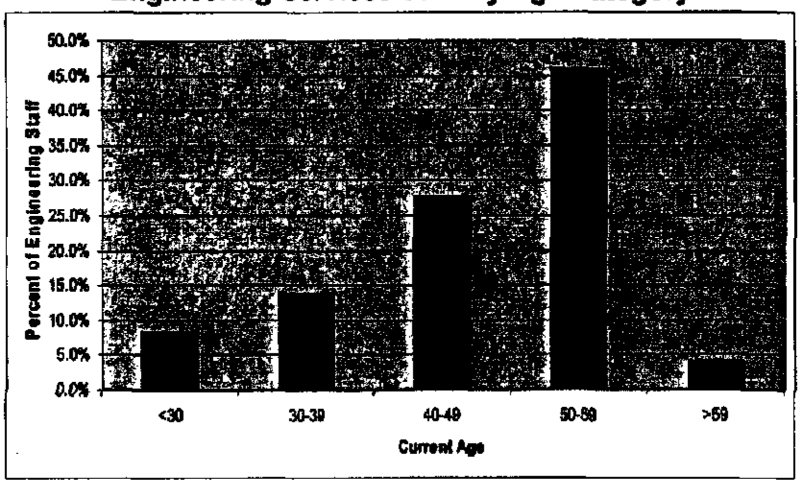


Figure 7-11
Engineering Services Staff by Age Category



As has been experienced within Regional Dispatching, the "one-for-one" replacement of experienced staff with entry level employees puts significant stress on overall outage response and we would expect degradation in CAIDI performance. This subtle effect is difficult to measure but is nevertheless real. We would encourage the Company to consider hiring and training as much as possible "in advance" of needs (as opposed to "one-for-one" replacement) to maximize the level of knowledge transfer from older, high-experience workers to their younger and skill-building replacements. We note that even the well-conceived PSI program cannot immediately replace the 30-40+ years experience represented by these 124 Distribution Linemen and 21 experienced Distribution Specialists (Designers).

<u>Operations Support</u>

Over 59 percent of the Substation staff is older than 50 as noted in Figure 7-12 below. Almost 79 percent of the Relay Testers as noted in Figure 7-13 below are also over 50. The extraordinarily high percentage of Relay Testers facing retirement within the next 10+ years poses a significant challenge to CEI's ability to properly maintain coordination within the substations.

Figure 7-12
Substation Staff by Age Category

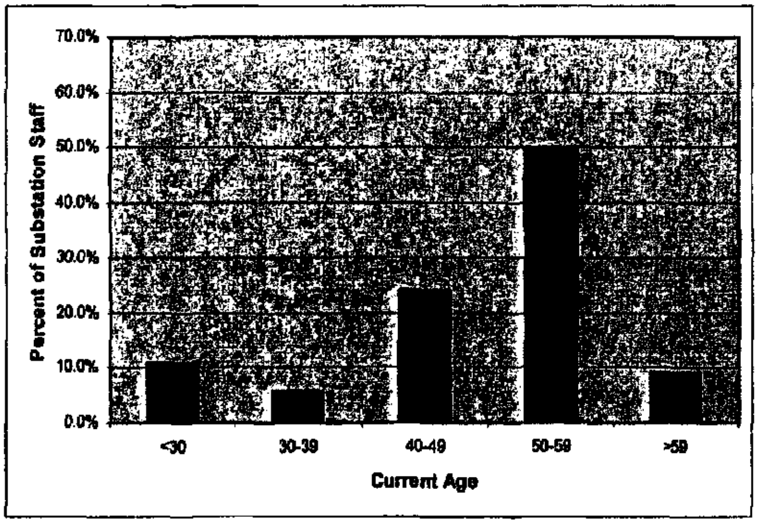
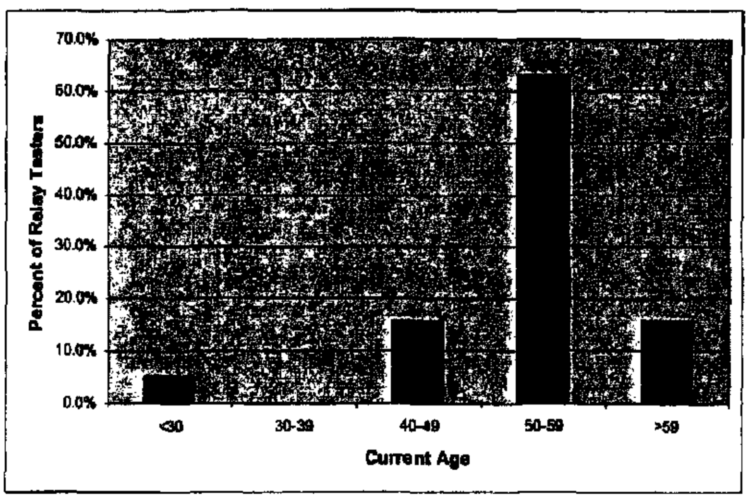
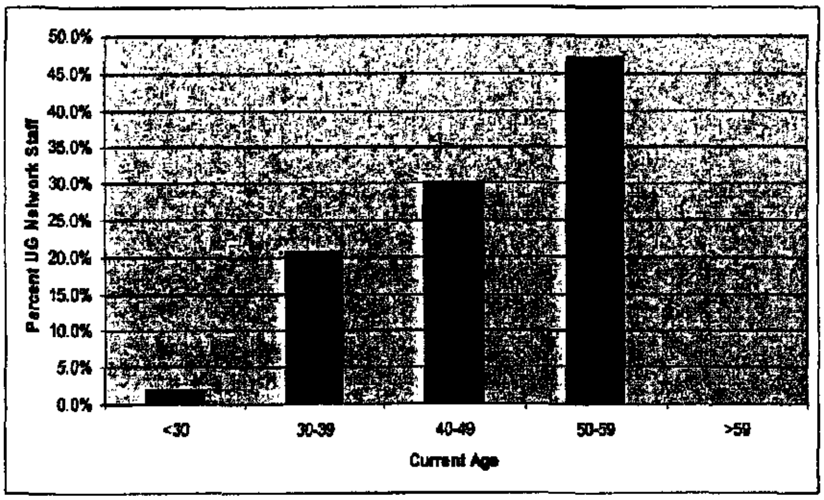


Figure 7-13
Relay Tester Staff by Age Category



Note that the Underground Network staff profile presented in Figure 7-14 below has virtually no representation among the 20- to 30-year old electricians. The convergence of the significantly aged buried cable replacement issues (noted in Section 5.0) and a retiring workforce (over 60 percent of the Underground Network staff over the next 10 years) in this work group will pose a significant challenge to CEI.

Figure 7-14
Underground Network Staff by Age Category



7.3.2 Workforce Management

This portion of the assessment addresses how the workforce and workforce management practices contribute to the company's effectiveness at maintaining and improving overall system reliability. It provides insights regarding the adequacy of CEI's staffing levels and competencies to keep pace with its inspection and maintenance program, improve outage response, and meet the requirements of the capital spending plan (specifically New Business and reliability/capacity projects).

Preventive and Corrective Maintenance

For purposes of analyzing CEI's capacity to perform preventive and corrective maintenance, our focus begins with the Company's existing inspection programs. The Company's preventative programs are outlined in the applicable sections of the FirstEnergy Substation Preferred Practices and Methods and the Distribution Circuit and Equipment Inspection Program Guides. Our analysis of the Company's corrective programs is related to CEI's ability to manage and address the resulting inspection exceptions (i.e. the "CM backlog").

What follows in this section is not an evaluation of the programs per se (which is separately addressed in Section 5.0); rather, it is an evaluation of the adequacy of CEI's staffing levels and competencies to meet the program requirements.

With respect to the actual inspections, CEI utilizes employees (particularly those on light duty) and contractors to meet the periodic requirements. The Company's success at satisfying these requirements varies between Operations Support (Substation) and Operations Services (Distribution) as described below:

Operations Support (Substation): Figure 7-15 below summarizes the Substation's Preventive Maintenance completion rate as measured actual vs. planned man-hours as of the end of 2006. CEI's substation completion rate was not satisfactory in 2005 and has certainly improved in 2006 (the East Region improved from 75.1 percent to 82.9 percent and the West Region improved from 54.7% to 76.4 percent). CEI currently anticipates having all substation inspection requirements completed and "current" by EOY 2007.

From a corrective maintenance perspective, the CM backlog for substation work is "current" and thus staffing appears to be adequate to resolve all inspection exceptions in a timely manner.

Figure 7-15
Substation Préventive Maintenance Performance (2005-2006)

Northern Region-East Ohio

Category	2005 Manhours			2006 Manhours			Backlog Trend	Backlog Carry
	Actual	Planned	% Compl	Actual	Planned	% Compl		
Transformers	1,618	2,062	78.5%	1,862	2,030	91.7%	(276)	168
Breakers	4,933	5,757	85.7%	2,888	3,278	88.1%	(434)	390
Relays	3,140	6,154	51.0%	3,154	5,194	60.7%	(974)	2,040
Mo. Sub Insp	4,246	4,657	91.2%	4,134	4,134	100.0%	(411)	0
All Other	387	436	88.8%	650	660	98.5%	(39)	10
Total	14,324	19,066	75.1%	12,688	15,296	82.9%	(2,134)	2,608

Norther Region-West Ohio

Category	2005 Manhours			2006 Manhours			Backlog Trend	Backlog Carry
	Actual	Planned	% Compl	Actual	Planned	% Compl		
Transformers	738	1,953	37.7%	1,044	2,354	44.4%	93	1,310
Breakers	4,397	9,618	45.7%	6,576	7,614	86.4%	(4,183)	1,038
Relays	3,581	7,561	47.4%	3,537	5,589	63.3%	(1,928)	2,052
Mo. Sub Insp	4,090	4,534	90.2%	3,215	3,245	99.1%	(414)	30
All Other	345	362	95.3%	504	669	75.3%	148	165
Total	13,149	24,028	54.7%	14,876	19,471	76.4%	(6,284)	4,595

Note: Planned includes Backlog Carry from previous year

Operations Services (Distribution): In contrast to the Substation Preventive Maintenance (Inspection) Program noted above, CEI has been able to satisfy the line inspection requirements as specified in the relevant inspection program guide and consistent with the ESSS requirements. The Company's challenge lies in its ability to address the exceptions discovered during the inspection process. Figure 7-16 below presents the Company's CM performance for Distribution Lines.

Figure 7-16
Distribution Lines Corrective Maintenance Performance

Area	2005			2006		
	Non-Pole	Pole	Total	Non-Pole	Pole	Total
Ashtabula	0	0	0	4452	1623	6075
Brooklyn	14	29	43	2852	4919	7771
Concord	0	0	0	2248	2075	4323
Euclid	0	0	0	0	0	0
Mayfield	0	260	260	1055	140	1195
Miles	1590	5555	7145	1741	11768	13509
Solon	0	0	0	772	42	814
Strongsville	0	0	0	838	379	1217
Westlake	14	86	100	1537	1112	2649
TOTAL	**1618**	**5930**	**7548**	**15495**	**22058**	**37553**

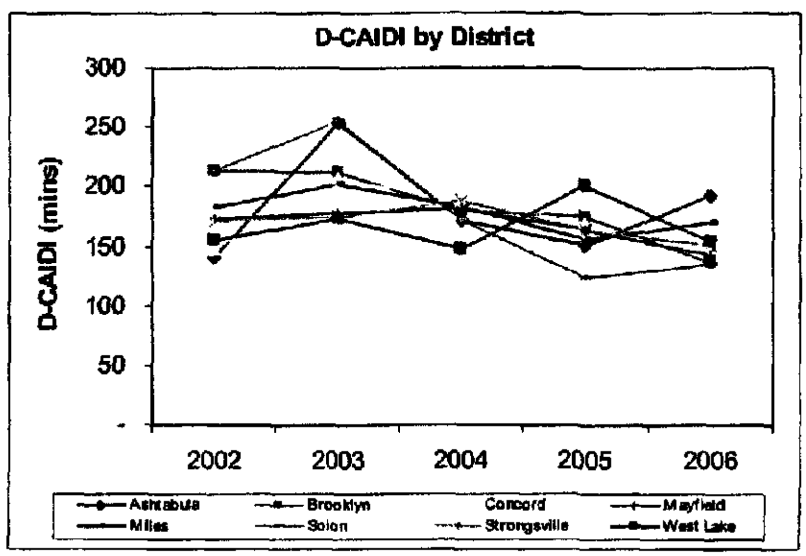
Figure 7-16 above notes a lines-related backlog of nearly 28,000 hours of pole replacement work and over 17,000 hours of non-pole related backlog that should be completed by EOY 2007. The pole related work has been contracted out to be completed as scheduled; however, it is doubtful that the CM backlog for non-pole related work (much of it accumulated during the 2005-2006 period) will be completed in 2007. Section 5.0 addresses the issues around CM backlog in the context of focus and prioritization; acknowledging that the shear number of deficiencies/exceptions is daunting, yet may or may not reflect a true view of overall reliability. Independent of any initiative to better identify the significance of/track completion of these exceptions/ deficiencies, the previously mentioned recommendation accelerate the hiring of new employees (to replace retiring employees) provides a resource pool to address this backlog (with the added benefit of on-the-job training).

Outage Response

CEI's noticeable improvement in outage response suggests that many positive factors - including effective utilization of existing staff, an optimal mix of employees and contractors, and sufficient staffing – has improved the Company's ability to restore service during system outages. Combined with the myriad of process and programmatic improvements (discussed in Section 6.0), the steady improvement in CAIDI noted over the past few years (Figure 7-17) is to be expected. Key areas, reflecting the integration of process and staffing include pre-mobilization and positioning of staff and use of the alternate shift. Both of these concepts are discussed fully in Section 6.0.

Figure 7-17
Distribution CAIDI by District

Reported District	2002	2003	2004	2005	2006
Ashtabula	140.84	254.06	171.74	150.01	191.84
Brooklyn	212.73	211.76	180.39	175.48	136.74
Concord	147.86	206.78	187.05	170.43	121.35
Euclid					
Mayfield	173.98	177.55	181.18	164.43	143.55
Miles	183.65	202.57	183.61	155.31	170.00
Solon	213.10	255.54	172.28	123.62	134.79
Strongsville	171.14	174.50	188.14	163.01	150.04
West Lake	156.30	173.65	148.17	200.38	153.70
Total	171.98	208.41	176.66	166.83	148.65



Construction

CEI has placed an appropriately high priority the Company's "summer critical" projects Most of the highest priority projects have been completed within the prescribed schedule. Proper planning and scheduling of other capital projects (most notably New Business and other Capacity or Reliability related projects) appears effective in that the capital spending plan for 2007 appears on track (with respect to projected EOY expenditures).

Clearly the lowest priority work is related to the lines-related CM activities (as noted in the prior section). The Company's key challenge is to establish the proper employee and contractor mix for addressing capital projects. For example, Figure 7-18 below notes that the 2006 New Business requirements alone accounted for 222 FTE's (and that's assuming a 12-month level effort when in fact most of the New Business work is performed in a 4-month period: July-October). Thus, there will continue to be an inherent conflict of priorities between capital projects and the more routine corrective maintenance work.

Figure 7-18
New Business 2006 Workload

Area	2006				
	NSNC	SU	NSRC	TOTAL	FTE
Ashtabula	374	893	6,344	7,611	30
Brooklyn	1,740	2,835	3,912	8,486	34
Concord	1,359	1,224	5,177	7,759	31
Euclid	0	0	0	0	0
Mayfield	2,363	3,495	5,927	11,784	47
Miles	705	1,279	3,322	5,307	21
Solon	54	834	1,365	2,252	9
Strongsville	1,684	643	3,559	5,886	24
Westlake	2,206	773	3,424	6,404	26
TOTAL	**10,485**	**11,976**	**33,030**	**55,491**	**222**

Figure 7-19 below shows the shift in CEI hours assigned to capital between 2006 and 2007 (over 40 percent increase), yet slightly less reliance on contractors (approximate 10 percent decrease) during that same time period. Capital spending is likely to increase (necessary to upgrade/replace the aging infrastructure) over the next 5 years. This increase in capital spending will be at a rate much higher than the anticipated net gain of employees. Combined with the expectation of no decrease in corrective maintenance during that same time period, CEI needs to consider a mobilizing and maintaining a larger contractor contingent on site throughout the year.

Figure 7-19
CEI Employee/Contractor Mix

Location	2006 Actuals		2007 Projected	
	Contractor Hours	CEI Hours	Contractor Hours	CEI Hours
Northern Region Asset Management	46,397	522	94,819	140
Northern Forestry	32	2,401	21,603	1,063
Northern Ohio Project Mgmnt Organization	112,963	-	12,164	-
Northern Line Operations-Shaker	-	-	-	1,788
Northern Line Operations - Concord	1,822	5,566	7,327	8,217
Northern Line Operations - Mayfield	2,860	5,458	(3,372)	8,183
Northern Line Operations - Brooklyn	47	11,895	30	17,884
Northern Line Operations - Miles	694	11,894	334	9,108
Northern Line Operations - Strongsville	255	8,822	61	6,469
Northern Line Operation - Westlake	300	3,791	773	17,832
Northern Line Operation - Euclid	-	-	-	359
Northern Region Transmission Maint	794	5,714	724	2,403
Northern Substation - East	748	13,712	5,351	28,299
Northern Substation - West	1,560	20,108	3,497	28,617
Northern Underground	896	18,239	597	22,223
Northern Service Install	366	275	124	-
Eastern Line Operations - Ashtabula	3,222	5,886	11,904	9,306
TOTAL	172,958	114,283	155,937	161,891

Figure 7-20 below provides a summarized view of our assessment of Company's workforce management performance as it relates to overall system reliability.

Figure 7-20
Workforce Management Assessment

Measure	*Performance*	Comments
Substation Preventive Maintenance		Significant PM Backlog on track for resolution by EOY 2007 (with existing staff levels)
Distribution Line Preventive Maintenance		*Mix of in-house staff (light duty personnel) and staff supplementation with contractors (former CEI employees)*
Substation Corrective Maintenance		Current staff able to keep pace with exceptions identified during substation inspections
Distribution Corrective Maintenance		Significant backlog. Resolution hinges on accelerated Senior level replacement strategy/increase in contracted work
Outage Response		Steady improvement in response time (CAIDI) noted since 2003
Capital Spending		On track. Increase in contracting Capital Projects will free CEI *resources to address Corrective Maintenance*

LEGEND

	ON TRACK
	CAUTION
	DANGER

7.3.3 *Reliability Culture*

A key ingredient in accelerating and maintaining system reliability improvement is the extent to which there is organizational commitment and alignment in meeting the performance targets. A second, essential ingredient is the employees' willingness and flexibility to make changes, whether these changes are broad and wide-sweeping (e.g. the Asset Management Transformation Initiative) or specifically targeted at key job tasks (e.g. changes in Operating Procedures).

In conducting our interviews within the CEI organization (ranging from Lineworker to Regional President and across a broad array of Departments), we were able to gain an appreciation for the CEI business culture (in terms of change readiness) and the degree of alignment among the organization around reliability-related topics. As a result, we observe that:

- CEI Management and Supervisory personnel are committed to meeting the established reliability performance targets. There are varying views regarding the "reasonableness" of these goals, but these views do no compromise the company's commitment to them.
- There appears to be an effective learning environment in terms of open discussion around reliability performance, constructive feedback, and clear accountability for reliability within the organization. We observe that these attributes are most prevalent in and around activities related to the Company's Monthly Reliability Meeting, which is well-administered, technically rigorous, and focused on performance improvement.
- The Company's recent operational improvement initiatives (e.g. "cut and run', storm mobilization, etc.) as discussed in the prior sections of this report are continually being reinforced to ensure that staff understand their impact on reliability (especially outage response).
- CEI's Asset Management Initiative (outlined in Section 9.0 of this report) offers the Company its biggest opportunity and its largest risk. Most employees appear aligned behind its concept and general intent, but there are varying degrees of understanding around its charter and implementation.
- The effective integration of newly hired personnel will be a critical success factor, particularly in the Regional Dispatching Function and as the new line workers and electricians replace the more senior personnel.

Figure 7-21 below provides a qualitative "barometer" of our assessment of CEI's readiness for change, a critical success factor in implementing the 10-year vision of sustained system reliability. The key attributes necessary to support continuation of this transformation include a strong sense of teamwork among the management team, clear and defined expectations, a strong sense of accountability for results, and a certain amount of flexibility in carrying out assigned tasks.

Figure 7-21
Change Readiness Assessment

ATTRIBUTE	LOW	RELATIVE POSITION	HIGH	COMMENTS
Group Optimism	*Focus on Barriers*		*Focus on Possibilities*	**Current State:** Committed to meeting goals but question achievability
	Individual Success		*Collaborative Success*	*Desired State: High Performance Team committed to meeting goals*
Trust and Involvement	Distrust in Relationship		Trust in Relationship	Current State: Strong individual efforts
	Authorization Orientation		Empowered Workforce	Desired State: Fully engaged in achieving organization goals
Dignity and Respect	Unable to Negotiate		Free to Negotiate	Current State: Somewhat doubtful regarding ability to shape outcome
	Don't Feel Valued		Feel Appreciated	Desired State: Become a willing partner in joining the team
Clarity of Direction	Different Values		Shared Values	Current State: Ready to take on the challenge; a bit reticent to take on the challenge
	Fuzzy/Changing Expectations		Clear Expectations	Desired State: Energized and Motivated with a high level of belief
Market Driven Focus	Bias Towards Analysis		Bias Towards Action	Current State: A bit too mired in the past; impacted by past performance
	Internally Focused		Externally Focused	Desired State: Lead the industry in innovative approaches/solutions
Performance Accountability	Political Decision Making		Meritocracy	Current State: Strong Performance Orientation but some confusion and frustration
	Blameful		Accountable	Desired State: Focused and effective Performance Management
Learning Orientation	Close Minded		Open Minded	Current State: Flexible, but a bit measured in response
	Risk Averse		Risk Taking	Desired State: Fast and Flexible, Highly Adaptive

CEI's *opportunities for improvement noted in Figure 7-21 above include the* continued need to break down barriers, take initiative, and focus outside of one's current structure. This reflects one of the primary challenges facing utility management today: The manner in which organization structure is allowed to shape behaviors and focus. With all the best intentions in mind, the more strategic and comprehensive solutions tend to get trumped by sub-optimal approaches originating from organizational rather than enterprise-wide views. CEI's plan to transition to an Asset Management orientation potentially addresses this issue.

7.3 *Summary of Recommendations*

The following specific recommendations are submitted recognizing that their anticipated benefits will likely not impact CEI's ability to reach the 2009 targets. The issues around knowledge management, leadership and supervisory succession, and proper assimilation of new staff require a well-conceived and robust staffing strategy built in concert with a comprehensive Asset Management strategy.

OS-1	Implement an accelerated hiring program in advance of a "one-for-one" replacement to allow enhanced assimilation of and knowledge transfer to new staff in replacing more experienced, retired personnel.

Discussion

The current policy of maintaining a one-for-one hiring policy with respect to replacements is certainly valid when doing a "like for like" replacement in terms of experience, knowledge, and leadership acumen. The practical reality is the replacement of the more seasoned individuals with "entry level" hires. Though the PSI program provides an outstanding foundation for a new hire, it does not replace the 3-5 year apprenticeship period necessary to become fully productive in the field, let alone the value provided by someone with over 20 years of field experience.

Recognizing that the probability of replacing a retiree with someone of equal knowledge is unlikely, the process should at least ensure that the apprenticeship period is completed as the more senior and experienced individuals leave the company. This will require an accelerated hiring profile, still focused on an ultimate 1 for 1 replacement, but allowing for a 2–year overlap to properly assimilate the new hire. This overlap approach will likely span a 10-year period, after which CEI can reevaluate its base staffing needs with an integrated work management program and a well-articulated contractor strategy. Figure 7-22 matches CEI's current hiring profile with our projection of attrition between 2009 and 2013 (by critical position). At the summary level, the plan calls for a net increase of 47 employees between 2009 and 2012 (and the hiring profile at least matches the projected attrition at each respective position). CEI is currently authorized to increase its head count by 50, commencing in 2009; which in essence will allow CEI to create a 2-year overlap in terms of assimilation of new staff.

NOTE: This increase need not be presented as permanent. Rather, it is intended to account for the time lag between the hiring of a new individual and the time it takes for that individual to become truly productive. Given the number of other initiatives that are ongoing within FirstEnergy/CEI (e.g. Asset Management Transformation, Increased Automation, Contractor Alliances), it would be premature to assume a higher staffing level on a permanent basis. By tying this initiative to the issues around maintaining a sustainable workforce/succession planning, CEI maintains the flexibility to remain at the increased staffing levels or return to original staffing levels, based on work level, improved processes, and employee/contractor mix strategies in the future.

Figure 7-22
Current Attrition and Hiring Projections

Function	Critical Position	5-YR Attrition	Year				
			2009	2010	2011	2012	2013
Leadership	Management	15	3	3	3	3	3
Operations Services	Engineer	10	2	2	2	2	2
	Lineworker	60	12	12	12	12	12
Operations Support	Underground Electrician	10	2	2	2	2	2
	Relay Technician	5	1	1	1	1	1
	Underground Technician	20	4	4	4	4	4
Reliability	Dispatchers	5	1	1	1	1	1
	TOTAL	125	25	25	25	25	25

Function	Critical Position	5-YR Hiring	Year				
			2009	2010	2011	2012	2013
Leadership	Management	35	7	7	7	7	7
Operations Services	Engineer	10	2	2	2	2	2
	Lineworker	99	19	20	20	20	20
Operations Support	Underground Electrician	20	4	4	4	4	4
	Relay Technician	10	2	2	2	2	2
	Underground Technician	20	4	4	4	4	4
Reliability	Dispatchers	10	2	2	2	2	2
	TOTAL	205	40	41	41	41	41

Taking a 3-year view (we recommend reassessing this profile annually based on actual attrition and the successful assimilation of new staff), the following incremental additions are presented (again, strictly for planning purposes as the actual attrition in 2008 will likely vary by position and number), indicating how to allocate the additional 50 positions currently planned for 2009:

Figure 7-23
Incremental Hiring Profile

Function	Critical Position	Incremental Hiring	2009	2010	2011
Leadership	Management	12	4	4	4
Operations Services	Engineer	0	0	0	0
	Lineworker	21	7	7	7
Operations Support	Underground Electrician	6	2	2	2
	Relay Technician	3	1	1	1
	Underground Technician	0	0	0	0
Reliability	Dispatchers	3	1	1	1
	TOTAL	45	15	15	15

OS-2	Increase focus on developing a Leadership and Management culture

Discussion

FirstEnergy has, over the years, identified high potential employees and groomed them for subsequent promotion into leadership/management positions. In fact, relative to the industry, the focus they apply to this process sets them apart from most utilities. That being said, the magnitude of the challenge confronting CEI (the shear number of Leaders and Managers retiring over the next 10-15 years coupled with the relatively low number of mid-aged/experienced individuals), may force a more aggressive recruitment strategy and earlier identification of individuals within the organization via promotion of a leadership culture. Two concerns need to be considered in adopting this recommendation:

- In terms of outside recruitment, this represents an opportunity and risk in reinforcing and/or improving CEI's culture. A potential hire needs to be reviewed relative to both technical and behavioral competencies to ensure the cultural dynamic remains consistent with the overall FirstEnergy strategy.
- With respect to internal staff development, care should be taken to ensure employee expectations are not inflated. What starts off as positively motivated, can lead to disappointment and disenfranchisement on the part of the employees if the program is not well-executed and the expectations well-articulated.

OS-3	Address CM Backlog within the current commitment time frame

Discussion

The requirement to perform patrol inspections on all distribution circuits every 5 years; and then close-out all noted exceptions within the next calendar year is more of a safety consideration than a reliability one (though there certainly is a relationship between the two). There are some alternate approaches to adopt in improving the efficiency and effectiveness of the current program (outlined in section 5.0). However, recognizing that the current ESSS requirements and commitments are driving the prioritization of resources and work planning processes, there appears to be a significant challenge in balancing these commitments with the Capital Projects.

In terms of outsourcing and contracting, FirstEnergy/CEI has done an appropriate job of segmenting out the type of O&M activities that can be contracted (e.g. Tree Trimming, Line Inspections, and Wood Pole Inspections). The majority of the items left are not scaleable enough or require too much inherent knowledge of a Company's diverse and aged system to efficiently contract to a third party.

Most capital construction work (particularly within the Distribution Line Function) can be outsourced. Therefore, we recommend that CEI align its in-house staff to address its CM Backlog within the current commitment time frame (and necessarily increase the amount of work contracted to third parties), but with the following caveats:

- Reassess the inspection requirements in terms of scope and frequency (i.e. the Feeder Backbone may warrant more frequent inspections than taps).
- Establish a variable criteria around the type of exceptions that require immediate action vs. action at the end of the next calendar year vs. those that need only be addressed as a matter of convenience (i.e. in conjunction with another activity, and not reflected as part of the CM backlog) or alternatively;
- Establish a more effective prioritization process with respect to identified deficiencies/exceptions ranging from highest priority (reliability and/or safety related) to inconsequential (no action required).

As a side note, the accelerated hiring profile recommended in section has the side benefit of providing additional resources to address the current backlog while simultaneously providing an ideal training opportunity.

8.0 Capital Expenditure Assessment

8.1 Purpose, Scope, and Approach

The purpose of this section is to summarize our evaluation of The Illuminating Company's (CEI's or the Company's) capital spending processes and actions and to develop an assessment of their impact on the company's past and future reliability performance. Our approach to this topic has been to analyze capital expenditures in a "top-down" fashion, focusing on the logical questions or issues that informed participants would raise related to the Company's capital spending with a special focus on electric system reliability.

Specifically, we seek to answer the following key managerial and regulatory questions:

- Are CEI's past, current, and planned capital funding levels adequate to achieve the targeted reliability performance and to sustain them over the 10-year time horizon contemplated in this assessment?
- Is the company's capital spending adequately focused on reliability issues? Specifically, has the Company been able to sustain an adequate level of reliability-related investment (e.g. asset replacement, some capacity investment, and system sectionalizing and automation) or has there been a pattern of "crowding out" reliability-related capital spending by company's other business obligations (e.g. relocations, new service connections, etc.)?
- Are the company's capital planning and prioritization *processes* (broadly defined) appropriate and effective for an electric utility of its size, condition, regulatory setting, history, etc.?
- Do CEI's capital planning processes (broadly defined) have *integrity*; that is, are they implemented as designed and do they achieve the desired results?
- Will the Company's recently initiated *Asset Management* focus have a positive or negative impact on CEI's long term reliability performance?

8.2 Overall Capital Expenditure Levels

As an introduction to this section of this assessment we note that a general indicator of the overall capital expenditure levels related the Company's distribution system can be characterized by the *Gross Distribution Plant Additions* as expressed in FERC accounting terms. Figure 8-1 below presents CEI's *Gross Distribution Plant Additions* (expressed in nominal dollars) from FERC Form 1 data for the period 1990-2006:

Figure 8-1
Capital Spending Levels (1990-2006)

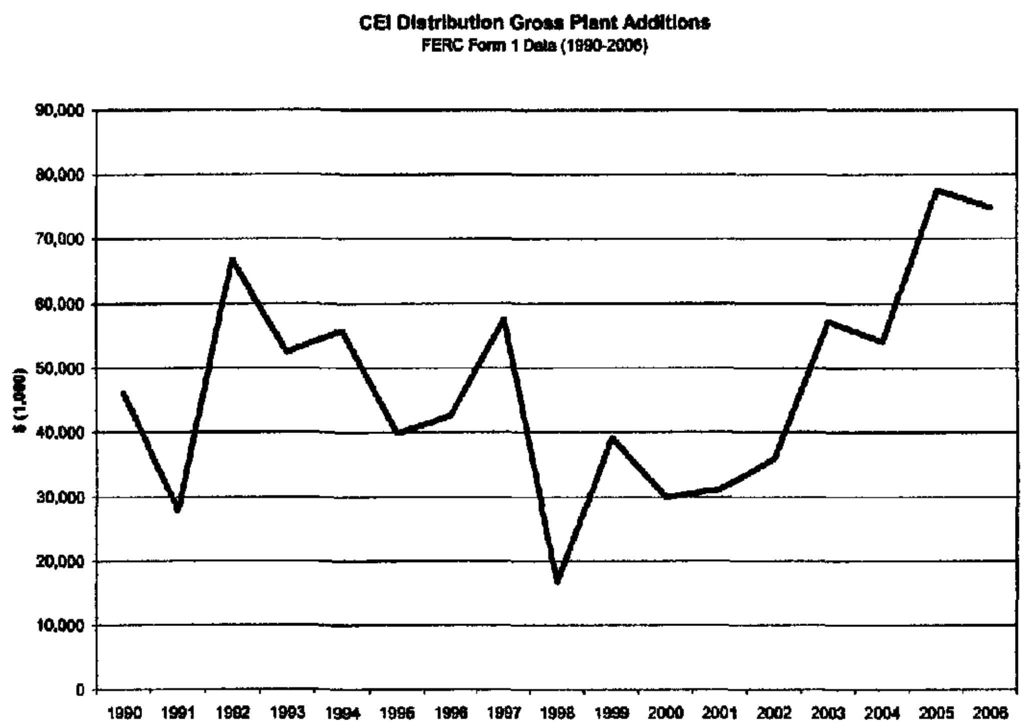


Figure 8-1 presents the Company's longitudinal spending trend. It naturally leads to a logical question - specifically, what is the "right" level of capital spending for the CEI system. Determining the "right" level of capital expenditure with precision for a large electric distribution network is undoubtedly a difficult challenge for engineers, system planners, Company management, and regulators alike. Many factors, including the age and condition of components, construction methods (overhead vs. underground), voltage, customer density, weather and environmental patterns, etc. all contribute to different spending requirements in different systems.

Correspondingly, comparative methods such as benchmarking at a detailed level are notoriously difficult to implement as a method to determine the "right" level because it is nearly impossible to normalize (i.e. "adjust") comparative spending patterns across systems to account for the key factors that drive spending.

Recognizing this overall context and the pitfalls related to such comparative analysis as noted above, our approach to this analysis has been to take a less stringent but no less relevant assessment of capital expenditures. Simply stated, we sought to assess the adequacy of CEI's relative spending in comparison to similar systems in similar environments. *In our experience*, the most appropriate way to make this relative comparison is using ratio of *Gross Distribution Plant Additions* over *Depreciation*. This measure provides a practical and generally stable *relative* measure of investment levels among systems; moreover, it offers an indicator (albeit imprecise) of "reinvestment" in the system.

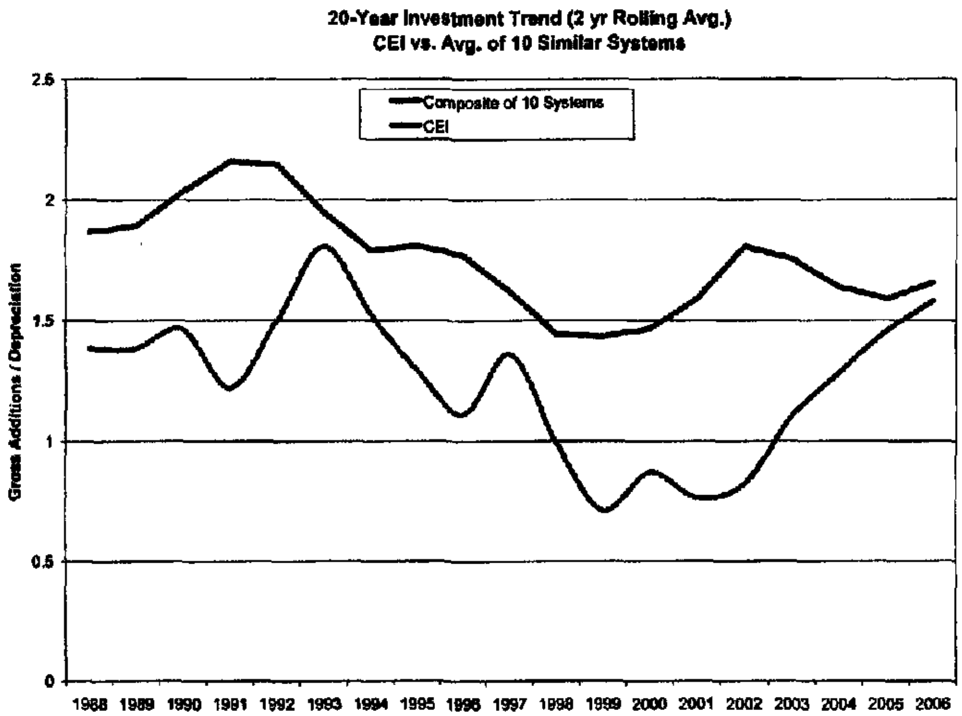
Before making our assessment, let us first explain our choice of this measure. Presuming the engineering life and accounting life of assets were synchronous, equipment costs were stable (i.e. no innovation or inflation), and the electric system is not growing (i.e. no relocations or new services), then the ratio of capital investment (as measured by gross plant account additions) over depreciation each year would theoretically be close to 1.0 (i.e. simple asset replacement). Naturally, no such hypothetical system or environment exists. In reality, many factors (inflation in material and labor costs, growth, relocations, etc.) drive this ratio up (i.e. investment would be greater than depreciation), while others drive it down (e.g. engineering life often exceeds accounting life, product innovation lowers costs, etc.).

In our experience, the combined effects of the elements noted above have resulted in the following general industry trends for this measure for U.S. based distribution systems:

- The ratio of *Gross Distribution Plant Additions* over *Depreciation* at an industry level has declined throughout the late 1980's and early 1990's from slightly greater than 2.0 to the 1.5-1.6 range in the late 1990's. We observe that these patterns occurred concurrently when:
    - Many U.S. utilities agreed to fix rates for extended periods as part of agreements related to merger approvals and "transition to competition" / deregulation initiatives. Thus, general capital spending was constrained because utilities had fewer opportunities to increase the rate base under these agreements,
    - Many commodity prices (steel, copper) and capital costs (nominal interest rates) fell and significant product innovation occurred throughout this period
    - General pricing levels stabilized from the higher inflationary patterns of the 1970's.
- Since the early 2000's the industry-wide level of capital spending (measured by gross additions relative to depreciation) has risen slightly from recent lows to stabilize in the 1.6-1.7 range.
- The general patterns noted above show up both at the industry (i.e. in aggregated form) and for most individual companies (with some variation in level that account for local conditions).

Figure 8-2 (below) presents a nearly 20-year trend of the ratio of *Gross Distribution Plant Additions / Depreciation* for CEI and for a composite of 10 U.S. electric utilities. The utilities in our reference composite measure were selected from similarly sized, Eastern U.S., urban/suburban systems. The composite was composed of: Columbus Southern, Dayton Power & Light, Detroit Edison, Duquesne Light, Commonwealth Edison, Kansas City Power & Light, Indianapolis Power & Light, NSTAR, PEPCo, and Pennsylvania Power & Light. To "dampen" the effect of extraordinary single year events (e.g. an extraordinary event), we have prepared this data in a 2-year rolling average approach:

Figure 8-2
CEI Capital Spending vs. Similar Systems (1988-2006)



An analysis of Figures 8-1 and 8-2 (above) leads to the following initial conclusions:

- The composite system pattern shown in the graph (Figure 8-2) does exhibit the general industry patterns described above. The Company's capital spending pattern over time has been consistent with the industry trends, albeit always at a *lower than average* level of spending for *all* years of this review. Indeed, among the sample utilities that comprise the composite sample noted above, CEI has exhibited one of the 1 or 2 lowest levels of investment among the composite sample in *every* year since 1990.
- The level of relative investment (as measured by gross additions / depreciation) for CEI was exceptionally low in the 1988-91 and 1997-2002 eras. These eras correspond to the period just after for formation of Centerior Energy (1986) and subsequent creation of FirstEnergy (1997).
- The general patterns noted above were not unknown to either CEI management or PUCO staff. The relatively low levels of capital spending were well documented and *understood* by all parties throughout the periods 1987-2007.
- The Company has exhibited a strong investment pattern since 2003 and one that is counter to general industry trends (i.e. CEI's investment has been increasing when the industry is relatively flat). This suggests that the Company has recently sought to return to a more "normal' level of investment.

- The Company's current capital plans also suggest that this elevated level of capital investment will continue in 2008 and beyond. Naturally, such plans can change, but current (relatively higher) capital expenditure levels are scheduled to be sustained over the next few years.
- At an aggregate level, the CEI electric system may require some increased investment in the coming years to "catch up" on deferred capital replacement that has likely occurred in the past 20 years.

8.3 Reliability-Related Capital Investment

As noted above, the absolute and relative level of capital expenditures at CEI has been increasing and is currently at a generally "normal" level for a system of its age, condition, growth patterns, etc. From a reliability perspective, the next logical question is clear - specifically, has the capital spending (especially the recent increases) been directed (generally) at improving reliability or has the reliability-related investment been "crowded out" by other capital commitments, including new service obligations, system relocations and other mandatory municipal work, and other "non-reliability" related investment?

Our approach to this analysis has been to examine the actual spending by budget category. Figure 8-3 (below) presents CEI's 2006 distribution capital expenditures by budget category:

Figure 8-3
2006 CEI Capital Budget by Budget Category

2006 Capital Budget Variance Analysis			
	Budget	Actual	Variance
Obsolete/Det Equip	$ 382,853	$ 24,590,014	$ 24,207,161
Storms	$ 253,249	$ 2,936,015	$ 2,681,766
Real Estate	$ 268,368	$ 1,075,530	$ 807,162
Failures	$ 6,197,126	$ 6,983,621	$ 786,495
Residential	$ 4,019,773	$ 4,647,702	$ 627,929
Industrial	$ (86,578)	$ 538,931	$ 625,509
Other	$ 40,000	$ 516,950	$ 476,950
Lighting	$ 1,824,905	$ 2,245,981	$ 421,076
Joint Use	$ 122,608	$ 132,526	$ 9,918
Jobbing & Contracting	$ 1,208	$ 4,554	$ 3,346
NonCap-Other		$ 2,679	$ 2,679
Regulatory Required		$ 2,005	$ 2,005
Veg Mgmt-Unplanned		$ 616	$ 616
IPP/Muni Connect		$ 273	$ 273
(blank)	$ *77,271*	$ 5,963	$ *(71,308)*
Veg Mgmt-Planned	$ 83,280	$ 227	$ *(83,063)*
Commercial	$ 4,097,553	$ 3,869,357	$ *(228,196)*
Damage Claims	$ 742,270	$ 450,274	$ *(291,996)*
Facilities	$ 783,638	$ 471,691	$ *(311,947)*
Corrective Maint	$ 1,548,624	$ 1,173,369	$ *(375,255)*
Meter Related	$ 3,016,673	$ 2,576,431	$ *(440,242)*
Tools & Equip	$ 1,176,018	$ 733,143	$ *(442,876)*
New Load	$ 2,120,327	$ 973,136	$ (1,147,191)
Relocs	$ 7,060,262	$ 5,887,631	$ (1,172,631)
Sys Reinforcement	$ 4,165,502	$ 2,269,164	$ (1,896,338)
Reliability	$ 23,112,099	$ 7,051,492	$ (16,060,607)
Grand Total	$ 61,007,029	$ 69,138,273	$ 8,131,244

Analysis of Figure 8-3 (above) yields the following observations:

- First, we note that internal budgeting processes are performed on a slightly different accounting basis than external FERC reporting (as presented in Section 8.2 above). Certain overhead loadings are included in FERC accountings that are not considered in the internal budgeting exercise. Thus, the values used across these sections (i.e. Figures 8-1 and 8-2 vs. Figure 8-3) are related to the same work, but are not presented here in identical accounting terms and thus the amounts do not tie.
- In 2006, CEI's capital expenditures were $69.1million, an amount $8.1million greater than the amount originally budgeted. A similar pattern occurred in 2005, when CEI's actual capital expenditure was $47 5 million or $11.7 million greater than originally budgeted (see Figure 9-5 below). Thus, we can find no evidence that FirstEnergy is "starving" the CEI system in recent years – further confirming the conclusions noted in Section 9-2. The CEI system is clearly an investment priority within FirstEnergy system of companies.

Several of the capital budgeting classifications changed in mid-year (a not uncommon event), resulting in some confusion in evaluating the relative measure of reliability related spending. Figure 8-4 below presents a reconciliation of the 2006 budget categories to estimate the real impact on reliability related spending:

Figure 8-4
2006 CEI Capital Budget – Reliability Reconciliation

2006 Variance Reconcilliation		
Non-Reliability Elements	Variance ($M)	
Storm	$	2.7
Misc. Non Storm / Non Failure	$	2.9
Major Over Budget Items	$	5.6
Misc Under Budget	$	(2.4)
New Load/Relos/Reinf	$	(4.2)
Major Under Budget Items	$	(6.6)
Reliability Elements	Variance ($M)	
Obsolete/Det Equip	$	24.2
Failures	$	0.8
Reliability	$	(16.1)
Increased "Reliability Spend"	$	8.9

Analysis of Figure 8-4 (above) in combination with Figure 8-3 (above) yields the following observations:

- Overall "reliability-related" (an imprecise term) investment was substantial, accounting for at least one-third of the 2006 capital spending. In our experience, this is a strong investment pattern when compared to other, similar systems.
- "Reliability-related" spending in 2006 was at least $8.9 million greater than originally planned. When considered in the context of the $8.1million in additional (unbudgeted) capital spending in 2006, it is clear that reliability-related investment was one of the company's highest priorities in 2006.

Thus, we conclude that the company has made a strong recent commitment to reliability-related spending in 2006 and shows evidence of similar investment patterns in 2007. There also appears to be little evidence that the there has been strong "crowding out" of reliability related investment in 2006.

Figure 8-5 below presents a similar budget assessment for the year 2005:

Figure 8-5
2005 CEI Capital Budget by Budget Category

2005 Capital Budget Variance Analysis	Planned	Actual	Variance
New Business	$ 3,248,334	$ 10,329,360	$ 7,081,026
Forced	$ 12,140,576	$ 18,330,383	$ 6,189,807
Condition	$ 6,272,823	$ 7,973,274	$ 1,700,451
Capacity	$ 179,203	$ 1,076,212	$ 897,009
Tools & Equip	$ 94,367	$ 771,166	$ 676,799
Street Light	$ 1,112,985	$ 1,624,364	$ 511,379
Facilities	$ 802,327	$ 941,784	$ 139,457
Vegetation Mana	$ 217,992	$ 329,148	$ 111,156
Jobbing & Contra	$ -	$ 61,630	$ 61,630
O&M	$ 1,750,709	$ 1,726,590	$ (24,119)
Meter Related	$ 3,326,135	$ 3,170,015	$ (156,120)
Other	$ 1,247,866	$ (90,368)	$ (1,338,234)
Reliability	$ 7,350,445	$ 3,231,449	$ (4,118,996)
	$ 37,743,762	$ 49,475,007	$ 11,731,245

Analysis of Figure 8-5 (above) yields the following observations:

- Budget categories changed from 2005 to 2006 (again, a not uncommon occurrence) making direct year over year comparisons difficult.
- In 2005 the spending shows that New Business and Forced (i.e. mandatory road moves, municipal work, etc.) investments were well in excess of plan, with spending on Reliability under budget by $4.1m.
- *Taken together, the combination of the 2005 and 2006 reliability-related spending* (i.e. the total of the two years) is still in excess of the budgeted amounts (+$8.9m (over in 2006) - $4.1m (under in 2005) or a net of +$4.8m over budget (combined 2005-2006)) and is (in total) still a strong component of the overall capital investment and at a high relative level .

8.4 Capital Planning and Improvement Processes

Our methodology to assessing CEI's *capital planning processes* (including *Project Prioritization)* is to evaluate whether they are truly holistic technical processes that begin with a clear identification and expression of system needs or issues (expansion commitments, reliability problems, etc.), are evaluated with a systematic and risk-considered approach that is designed to achieve optimal results given reasonable constraints (seasonal scheduling, availability of specialty tools or crews, etc.), and are automated to achieve systematic and reproducible results where appropriate.

Our standard for assessing these processes is not to expect a single, "best" way to approach these processes; rather, to verify that CEI is at a level of process maturity and effectiveness consistent with its size, condition, regulatory requirements, etc. and identify those area where the company may be able to improve by implementing industry best practices from other leading utilities.

Our approach to measuring the *Integrity* of CEI's capital-related business processes is to assess whether these processes are implemented as planned from a multitude of dimensions. First, is the capital planning process an integral part of overall business planning and budgeting process (e.g. setting business objectives, resource strategy, etc.), rather than an adjunct activity that requires subsequent integration / coordination with other plans? Second, are the capital plans implemented as planned and actively managed? Finally, are the inevitable changes to the plan (due to external events, new information, new priorities/issues, etc.) handled in a manner that is consistent with the decisions made during the "normal" annual planning cycle?

As a large, mature, investor-owned electric utility with a substantial base of technical expertise, we would expect to find CEI conducting capital planning and improvement processes that have the following characteristics:

- **Holistic** – the processes should integrate all capital requirements (new business, reliability, etc.) into a single planning and evaluation process.
- **Need- / Issue- Driven** – the origin of capital commitments should be clearly and systematically defined business- or technical-needs that are expressly satisfied through investment in the electric system. Actual investment alternatives may satisfy multiple needs / issues (e.g. reliability and capacity) and thus further highlighting the importance of the *holistic* objective (noted above).
- **Risk Measured** – the safety, technical, economic, and socio-political risks of funding or not funding a particular investment should be an integral part of the decision-making process. Such risks should incorporate both the probability and the consequence of failing to mitigate or eliminate system needs / issues.
- **Structured** – The nature and scope of the investments (e.g. Obligation to Serve, Reliability, Mandatory vs. Discretionary) should be well classified (and validated) at the time the need or issue is identified.
- **Standardized and Documented** – The processes should be highly standardized and not dependent on key individuals, well-documented to enable ongoing training and process refinement / improvement, and create an auditable "paper-trail" to ensure proper management and post-investment assessments.
- **Peer- , Supervisor- and Executive-Reviewed** – The inputs, analyses, decisions, and results of the processes should be actively and systematically reviewed and approved by all levels of the management team to ensure that the proper technical and regulatory requirements are met.
- **Annual Scope** – They should, as a minimum, be developed as part of an annual planning effort (multiple years are preferred) and should be systematically reevaluated throughout the year. Such defined annual plans (as opposed to continuous or 'rolling' plans) enable management to assess the impact of new or deferred projects on overall planned system performance.
- **Integrated with Budgeting and Authorization** – The capital planning effort should be an integral part of the annual budgeting process and the spending authorization process; there should be little or no effort necessary to "fit" the capital plans to operational budgets.

- **Resource Independent** – Initial definitions of work should be independent from the available resources; in short, the "work should define the required resources (both company and contractor)", not the other way around.
- **Automated** – The processes should be reasonably automated with packaged or customized software tools to encourage standardized, systematic analyses across participants, general process efficiency, and sound record-keeping of results.
- **Dynamic** – The process should be capable of integrating changes to the plans throughout the year and these changes / alternatives would be evaluated through the same process.

Our specific approach has been to review CEI's capital planning and improvement process in the context of the expectations noted above through a series of interviews with key participants and to review the company documents that address these topics.

CEI's planning process as described by the Company's planning professionals is composed of the following elements:

- Planning engineers define system-based needs that drive the analysis of potential technical options or alternatives. These options are evaluated for both technical and economic performance (they may have both capital and maintenance impacts) and are expressed or summarized as a *Request for Project Approval* and known informally as an "RPA".
  - These electric system-based needs are classified using a common issue / need framework known as the *Investment Reasons*. These classifications are presented in Figure 8-6 below. A subset of these needs or issues is classified as *Mandatory* reason and will be funded if technically approved.

Figure 8-6
CEI Investment Reason Categories

Classification Category	Roll Up	Investment Reason	Definition
"C" Mandatory	Cap	CAP-New Load	Costs associated with projects required to improve relieve or correct an existing or projected voltage or thermal condition. Some specific examples include new substations, transformer additions, transformer replacement, substation capacitor installation, line capacitor installation, and feeder/exit additions.
	Cap	CAP-Sys Reinf	Costs associated with reinforcing our infrastructure. This includes line terminal upgrades, line/wave traps, line reconductors (know line rating is under rated), line upgrades (pushing more amps through line because load has increased), replacement of a breaker due to load or interrupting current limitations, rebuilds to improve capacity
	Real estate	FAC-Real Estate	Cost associated with the purchase, sale or lease of land or property, rights of way, easements, etc.
	Forced	FRC-Failures	Costs associated with replacement of failed equipment and devices.
	Forced	FRC-IPP/Muni Connect	Costs associated with interconnections requiring an Interconnection Agreement to be signed by the interconnecting party. Includes charges due to scheduled or unscheduled plant shutdowns.
	Forced	FRC-Regulatory Req	Costs associated with Dx or Tx line and service projects required by federal or state regulatory bodies. These projects may not conform to our normal design and planning criteria's. Examples include replacing PCB equipment, changes to correct clearance problems, etc.
	Forced	FRC-Reloca-Highway	Costs associated with roadway or bridge projects.
	Forced	FRC-Reloca-Other	Costs associated with relocation of facilities not associated with road or bridge projects. Examples include moving overhead lines for swimming pools or sheds, etc. Moving poles for aesthetic reasons, etc. These costs can be billable or non-billable.
	Forced	FRC-Storms	Costs associated with all weather related conditions.
	Meter	MTR-Meter Related	Costs associated with the installation or removal of meters.
	New Business	NEW-NB Commercial	Costs associated with providing service to these new customers that are primarily in the business of sale or transfer of a product or service. This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution system.
	New Business	NEW-NB Industrial	Costs associated with servicing those new customers whose business primarily involves changing the form of a product. This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution or transmission systems.
	New Business	NEW-NB Residential	Costs associated with servicing those new customers considered to be private households, including apartments, townhouses, condominiums and vacation homes. This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution system.
	Other	OTH-Damage Claims	Costs and revenues resulting from First Energy claims against an outside party
	Other	OTH-Joint Use	Costs and revenues associated with the joint occupancy of poles.
	Street Lighting	STR-Lighting	Costs associated with all forms of street lighting and lighting services. Includes community lighting, dusk to dawn and area lighting for private customers, ornamental lighting, public street and highway lighting, for municipalities and associations. This includes both scheduled and unscheduled work.
"B" Improve Reliability	Reliability	REL-Reliability	Expenses incurred to improve/reinforce the reliability of the infrastructure assets. Examples include SCADA/MOABS additions, reclosure addition to Dx lines, relaying replacements, transrupters, CRI improvements, TX reliability index, etc. These costs may or may not be directed by a regulatory body.
"B" Maintain Condition	Condition	CND-Obsolete/Def Eqp	Costs associated with replacements of equipment due to inability to get parts, or outdated equipment. RTU replacements of aging equipment, full line rehab due to aging poles, transformer replacement due to gassing, breaker replacement due to poor performance or age, substation spare equipment, rebuilds because lines are falling down, carrier set replacements, batteries/charger replacements, oscillograph DFR replacements.
	Other	OTH-Other	Costs associated with miscellaneous type categories. Examples are accounting type entries (i.e. accrued vacation, uncleared construction indirects, system enhancements, etc.).
	O&M	O&M-Corrective Maint	Program or non-program O&M costs associated with the unplanned repair and maintenance of the system, which may or may not be scheduled. This excludes any capital work resulting from corrective maintenance.
	O&M	O&M-Operations	O&M costs associated with the activities related to managing and directing the operations of the company.
	O&M	O&M-Preventive Maint	Program or non-program O&M costs associated with the planned repair and maintenance of the system, which may or may not be scheduled.
	Vegetation	VEG-Veg Mgmt-Planned	Costs associated with a planned tree trimming and vegetation management program
	Vegetation	VEG-Veg Mgmt-Unpland	Costs associated with an unplanned tree trimming and vegetation management program.
"A" Value Added	Facility	FAC-Facility-Corp	Costs associated with corporate facilities projects. Includes all costs at main GO facilities related to structures and improvements, costs for furniture, equipment, roofing, landscaping, paving, electrical and HVAC.
	Facility	FAC-Facility-Region	Costs associated with regional facilities projects. Includes all costs at regional locations related to structures and improvements, costs for furniture, equipment, roofing, landscaping, paving, electrical and HVAC.
	Jobbing & Contracting	J&C-Jobbing & Contrc	For profit work associated with customer work either generated internally or requested specifically by customers. This is expense and not Capital work.
	Tools	Tool-Tools & Equip	Capital or O&M expenses associated with the purchase and upkeep of tools and work equipment. This also includes transportation tools and equipment.
	Billable	BL-NonCap-Mutual Stm	Billable costs associated with assisting other utilities as a result of weather-related conditions. Settlement rule should be 186001.

- The project's economic dimensions (cost, expected revenue, etc.) are captured and summarized in the Capital Analysis and Risk Tool (CART) system.
- The best alternative is then determined to be an "accepted" solution by the local planning staff.
- The Company's planning staff noted that before 2005 there was a rudimentary risk assessment conducted with each project. In 2006, the Company set out to enhance and further standardize its risk assessment process and made an effort to automate these standards in software tools. The company currently uses a standardized *Impact* and *Likelihood* approach to measure risk as presented in Figure 8-7 below.

Figure 8-7
Risk (Impact and Likelihood) Definition Standards

	0	1	2	3		Rating
Impact						
Loss Avoidance						
Description: financial impact	$0 to $100k	$100k to $1M	$1M to $5M	More than $5M	0	0.0
"realistic worst case" (rules of thumb)						
Regulatory Impact =	$200,000 per minute SAIDI increase					
O&M Expense =	$0.625 per customer per hour					
Revenue Impact (Tariff) =	$0.070 per customer per hour (T&D)					
Other Expense =	$0 Special Equipment, Contract Labor, Contract Penalties, etc.					
Non-Financial Impact						
Safety	No impact reducing potential exposures or improving safety performance	Minimal impact reducing potential exposures or improving safety performance	Moderate impact reducing potential exposures or improving safety performance	Current violation of OSHA and/or NESC		Max
Political/Regulatory	No Impact	Minor Impact (locally)	Moderate Impact (PUC Reporting)	Significant Impact (Regional Action)		0.0
Customer Impact	No Impact	0-2,500 Local	2,500-10,000 PUC Notification	>10,000 Major Outage		Avg. / Max
Outage Duration	< 1 Hour	> 1 Hour < 8 Hours	> 8 Hours < 24 Hours	> 24 Hours		0.0 / 0.0
				Impact Score =		0.0
Likelihood						
Application/ Asset Performance						
Performance history	No Issues	Minor Issues (Sporadic)	Minor Issues (Increasing Trend)	>1 Major Perf. Issue		Avg
Life expectancy	New - long term life expectancy	Component is beyond life expectancy - maintainable	Component is beyond life expectancy - non maintainable	Definitive signs of eminent failure within one year		0.0
Asset Utilization						
Asset Utilization	Within nameplate rating	Over nameplate rating (Flat Trend)	Over nameplate rating (Increasing Trend)	Exceeding Moderate Loss of Life		0.0
				Likelihood Score =		0.0

- Under the normal, annual planning cycle, the "accepted" solutions enter a formal, multi-level review process that ultimately results in an approval, deferral, or rejection of the proposed RPA. If the RPA is approved, the associated capital expenditure will become a component of the CEI capital budget. The current review process includes the following levels:
  - A *Peer Review* by the CEI planning staff to ensure that options are exhaustively and correctly technically analyzed,
  - An *Operating Company Review* that in the past (pre-2006) has been composed as an assessment by Regional Directors; it has recently (2006) been expanded to include operating company officers,
  - An FE *Corporate Portfolio* review that is also performed by a Capital Review Committee of leaders across the FirstEnergy system.
- The primary output of this multi-phased approach is a project ranking or prioritization. This process ranks the discretionary spending based on system impact and risk.
- Periodically throughout the year, unplanned or materially revised RPAs will reenter this assessment process and will be addressed on an exception basis.
- Throughout the year, approved projects are begun after authorization when construction activities must be initiated according to construction plan. These projects are commissioned in the SAP system through the definition of the *Work Breakdown Structure* (WBS).
  - Prior to 2007, these projects were assigned to the respective construction management professionals (in Lines, Substations, etc.) for management and implementation. Then and now, project and schedule results are monitored monthly through the CEI Project Status Update Meeting, and a project-level review of all active projects is performed with particular focus on the summer-critical projects addressing high risk issues.

- In 2006, the Company initiated a monthly *Capital Allocation Meeting* (CAM) to more actively monitor and manage the execution of the capital expenditure plan; and as such is a detailed review of variance reports and changes to the plan.

Our overall assessment of CEI's capital planning and prioritization *processes* can be summarized in the following way:

- CEI's processes during the past few years have exhibited many of the attributes that *constitute a sound planning and prioritization process*. They are holistic and need-/issue-driven. The Company and FirstEnergy overall have made efforts to standardize key elements in the issue identification, project classification, and risk definition steps. Such standardization allows for automation, record keeping, and consistency of decisions.
- CEI's risk assessment scoring process could be currently described as adequate and consistent with industry standards and practices. It has a strong, reliability-focused *Impact* measurement structure. However, the risk assessment could be enhanced by adding a probabilistic (rather than a substantially qualitative) estimate of the *Likelihood* measurement dimension. This is a recently added element in the planning process and should improve its overall effectiveness.
- Since approximately the year 2000, many major U.S.-based investor-owned utilities (of a size and scope similar to CEI and FirstEnergy) have made significant improvements in their capital planning processes and tools to realize the characteristics outlined in the opening paragraphs of this section. To date, FirstEnergy and CEI could be best be described as making adequate but by no means industry-leading progress in these areas.
- Implementing industry best practices would lead to the development of integrated systems to link the investment evaluation process and subsequent prioritization and funding to overall strategy and risk mitigation. In applying an approach that disaggregates the investment decision from resource utilization considerations, CEI will make significant strides in the area of Asset Management.
- One noteworthy element that relates to these capital-related processes is CEI's implementation of a Capital Prioritization process (this project was inaugurated during the 2nd quarter 2007 just as this assessment was initiated). The approach and toolset (one of several available in the marketplace) has been developed over multiple years with numerous other large, investor-owned electric utilities. Consequently, it is a proven approach, embodies many of the industry's leading practices, and should expedite the Company's development in these areas.

8.5 Capital Processes Integrity

Our assessment of the *integrity* of CEI's capital-related business processes has been focused on whether these processes have been implemented as they are designed. This assessment would ideally have multiple dimensions, specifically:

- Does CEI, in fact, execute the planning processes as they are designed?
- Are the capital plans implemented as they are planned (i.e. – did "approved" projects actually get built and on what schedule)?
- Are the inevitable changes to the plan (due to external events, new information, new priorities/issues, etc.) handled in a way that is consistent with all other investments?

From our interviews and a review of CEI's records related to the Company's capital planning and prioritization processes, it is apparent that the processes as described by company's management and technical team are being implemented as intended. These processes have high visibility and a large number of participants in all of the varying process stages defined above. There is an appropriate documentary trail to support that its conclusions and actions are implemented as planned.

At the present time the Company lacks a rigorous data relationship capability between the RPA database (a Lotus Notes application) and the SAP system (which tracks actual project activity). Although such conditions are less than ideal, they are also not uncommon given the complexity of maintaining interfaces between enterprise-based transaction systems (such as SAP) and active, Company-developed planning tools (such as the RPA system).

Consequently, it is not possible to easily track and report "end-to-end" the performance of all RPAs through construction and completion (or deferral) in an automated way. Ideally, our analysis would have included an assessment to test whether the capital plans as approved from the RPA database were implemented (wholly or partially) as they are planned in SAP (i.e. – did "approved" projects actually get built and on what schedule)? Similarly, we also would have checked the process "in reverse", to determine that all projects that were constructed do indeed tie rigorously to an RPA (or not). At the present time such an assessment is not available in an automated way.

In independent assessments such as this study, we are frequently challenged to assess an organization's overall Asset Management capability (our frame of reference is our global experience with utilities, not solely a U.S. perspective). The technology-related information issues noted above are a critical dimension of this assessment. Figure 8-8 below highlights a perspective on the typical evolution that organizations follow as they transform to an Asset Management model:

Figure 8-8
Typical Evolution of Asset Management Capabilities

Pre-Asset Management Companies	Novice Asset Managers	Competent AM Companies	World Class AM Companies
• Organized in Geographic Division Structure • All Asset Management decisions made by local division management • Annual budget allocation "negotiated" among division leadership • Design standards sometimes centralized • Maintenance and operating standards usually flexible for local application	• Good general understanding of Asset Management principles • Organization Structure reflects AM/NS split • Committed to improving AM effectiveness and competence over time • Struggling with role clarity, SLA administration, <u>accessibility of key information, and systems needs</u>	• Rigorous understanding of all AM principles • Best in class AM process design implemented • Robust asset register in service with accurate and timely information • Effective AM Information systems in place that fully meet <u>AM decision support needs</u> • Roles and relationships functioning well • Full life cycle plans in place and integrated into business plans	• <u>Seamless integration between corporate finance and asset strategy</u> • World class AM I/T Portfolio in place and ready to accommodate AM for others • Network and business performance significantly better than less mature AM companies • High credibility with Regulators • Network services and Asset Management are fully contestable

As it applies to <u>the IT-related elements</u> of the Company's capital planning and prioritization processes, CEI would generally fall in the novice / competent categories (based on a global scale of reference). The Company does have solid planning tools (RPA database, CART system, SAP) and is implementing new and better one (e.g. the

Navigant Consulting model), however data accessibility and more importantly data integration are weak. This is not an unusual condition for U.S.-based electric utilities.

CEI acknowledges at various levels in the organization the need to make better ex-post assessments of the actual impact of specific investments and use these assessments as key inputs to the project / alternative design process. This awareness is a critical first step toward defining the requirements and realizing the benefits of such information systems capabilities – which typically have a strong emphasis on data and systems integration.

This information improvement issue is one of the stated objectives of the Company's current *Asset Management* initiative, achievement of which will likely not occur until 2008 and beyond.

8.6 Asset Management Initiative

In late 2006 FirstEnergy initiated an Asset Management (AM) initiative aimed at improving the effectiveness of its capital investment programs, both in terms of how projects are selected and approved and how projects are managed in implementation. Given the 10-year perspective of this assessment, the implementation of this AM initiative at CEI will have a very important effect on the Company's ability to improve reliability especially in the context of the aging infrastructure challenges facing First Energy (and many other U.S. utilities).

The focus on this FirstEnergy-wide AM initiative has been to enhance how projects are managed and improve the quality of asset-related information and decision-making. It has included new organizational elements at both the holding company (FirstEnergy) and operating company (CEI) levels. CEI's AM function reports to the President of CEI and also has a matrix reporting relationship to the FirstEnergy Vice President – Asset Oversight. It will also include the implementation of new business processes and tools (noted above).

The CEI Director of Asset Management is the primary CEI manager responsible for implementing this initiative. There are 3 managers who report to the Director of Asset Management, responsible for the following three AM functions:

- **Project Management** - The project management responsibilities are focused on the timely, cost-effective, and safe implementation of the capital work program.
- **Portfolio Management** – This represents the continuing process of managing all of the Company's capital projects in the context of the overall schedule and budget. Project status and cost data is updated bi-weekly and this enables monthly reporting for the entire Company's capital project portfolio relative to budget and plan.
- **Asset Strategy** – This includes the implementation of 10 newly created positions known as Circuit Reliability Coordinators (CRCs) at CEI (FirstEnergy is implementing 70 such positions around the FirstEnergy system). CRCs will be responsible for circuit level asset history and analysis, data management and standardization, monitoring circuit-level reliability performance, and formulating projects and programs as they relate to their responsible circuits. The Company's vision is that these CRCs will be the "owners" of these circuits, with a strong sense of responsibility for their reliability performance, and will coordinate the investment projects related to their respective circuits through the necessary inspection, technical analysis, and financial / budgeting processes.

The company has a parallel corporate and operating company organizational structure. The operating company managers and director (noted above) are responsible for the implementation of these functions within CEI; the parallel corporate role is the Company's overall process owner and its manager is responsible for standardization of systems, processes, and tools across the First Energy system

FirstEnergy's corporate Asset Management leadership team has expressly recognized (and is actively managing) three primary challenges related to its Asset Management initiative. These include

- **Timing** – The FirstEnergy leadership team has set an aggressive time line to initiate the Asset Management initiative, especially as it relates to implementing the capital prioritization process and the hiring of CRCs. This is a major organizational change, with many new roles and interfaces between new participants and existing business processes and roles.
- **System Knowledge / Root Cause Analysis** - The Company is actively seeking ways to improve its ability to conduct "root cause analysis" of reliability issues. The AM leadership appropriately recognizes that this is a foundational element of improving asset-related investment decisions and will also be closely linked to the quality of the Company's asset data (see below).
- **Asset Data / Information** – FirstEnergy is seeking to become far more "predictive" (rather than "reactive") to asset failure patterns and far more accurate in the estimation of impact or benefit of system investments. A key element necessary to achieve these objectives is improved asset information (age, condition, failure patterns, loadings, etc.). This need is one of the driving factors behind the design of the new CRC role.

We generally concur with the Company's goals for the Asset Management initiative. Our observations related to this area were that the CEI executive management and FirstEnergy corporate AM leadership team have strong and clear views of scope, approach, and implementation of the AM initiative.

However, at the CEI staff level we noted uncertainty among departments about new or changed roles, responsibilities, and process interfaces (e.g. the role of CRCs v. existing inspections, the technical qualifications and expectations of the CRCs, etc.). Such uncertainty in the early stages of a major operating change is not unusual and is not yet a source of major concern. Moreover, as noted in Figure 8-8 above, we note that this struggle for "role clarity" is a very common characteristic of early stage AM transformations.

Our overall interpretation of the Company's Asset Management initiative in the context of this reliability assessment is straightforward – we believe it absolutely represents the <u>greatest opportunity</u> for the Company to make rapid, cost-effective, and truly sustained improvement in electric system reliability. At the same time, we also believe it represents perhaps the <u>single greatest risk</u> to overall system reliability because of the potential uncertainties created by any major organization restructuring and new processes.

Figure 8-9 below summarizes some of the major risks and opportunities that CEI will face as it develops its Asset Management organization: