Large Filing Separator Sheet

Case Number: 08-935-EL-SSO

File Date: 10/15/2008

Section: 1 of 2

Number of Pages: 150

Description of Document: Testimony of David W. Cleaver

FILE

Office of the Ohio Consumers' Counsel

Your Residential Utility Advocate

Janine L. Migden-Ostrander
Consumers' Counsel

RECEIVED-DOCKETING DIV

2008 OCT 15 PM 5:24

PUCO

October 15, 2008

Ms. Renee Jenkins, Director
Public Utilities Commission of Ohio
180 East Broad Street, 7th Floor
Columbus, Ohio 43215-3793

Re: Filing of OCC Witness Cleaver's Testimony in the Public Docket, Case 08-935-EL-SSO (FirstEnergy Utilities)

Dear Ms. Jenkins:

This letter notifies the Public Utilities Commission of Ohio and the public in the above-captioned case that the testimony of OCC Witness Cleaver, originally filed under seal on September 29, 2008, is being re-filed as a public document. That testimony was originally submitted with an OCC Motion for Protection, based on concerns over whether the FirstEnergy electric distribution utilities considered certain information to be confidential.

Counsel for the Applicants, the FirstEnergy electric distribution utilities, affirmed at the October 10, 2008 status conference that the testimony of OCC Witness Cleaver does not contain confidential, trade secret information. Thereafter, OCC counsel stated (without objection) that OCC would serve parties to the case with the previously confidential version of the testimony and submit this letter to the Docketing Division. Accordingly, OCC's Motion for Protection is hereby withdrawn.

Very truly yours,

Richard C. Reese

Richard C. Reese
Assistant Consumers' Counsel

Cc: Persons listed on electronic service list

sam@mwncmh.com
john.jones@puc.state.oh.us
william.wright@puc.state.oh.us
drinebolt@aol.com
dboehm@bkllawfirm.com
BarthRoyer@aol.com
jbentine@cwslaw.com
Cynthia.A.Fonner@constellation.com
mhpetricoff@vssp.com
gas@bbrslaw.com
leslie.kovacik@toledo.oh.gov
lkeiffer@co.lucas.oh.us
mitch.dutton@fpl.com
LBell33@aol.com
robinson@citizenpower.com
lmcalister@mwncmh.com
jclark@mwncmh.com
dneilsen@mwncmh.com
Dane.Stinson@BaileyCavalieri.com

burkj@firstenergycorp.com
korkosza@firstenergycorp.com
haydenm@firstenergycorp.com
elmiller@firstenergycorp.com
mawhitt@jonesday.com
ricks@ohanet.org
henryeckhart@aol.com
cgoodman@energymarketers.com
Vollmse@ci.akron.oh.us
jpmeissn@lasclev.org
LGearhardt@ofbf.org
gkrassen@bricker.com
gdunn@szd.com
dex@bbrslaw.com
wis29@yahoo.com
eric.weldele@tuckerellis.com
david.fein@constellation.com
gwung@mwe.com

OCC EXHIBIT NO. 2

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-935-EL-SSO

DIRECT TESTIMONY

of

DAVID W. CLEAVER

ON BEHALF OF
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485
(614) 466-8574

September 29, 2008

TABLE OF CONTENTS

		Page
I.	INTRODUCTION	1
II.	PURPOSE OF TESTIMONY	8
III.	FIRSTENERGY HAS NOT ADDRESSED THE SERVICE QUALITY ISSUES RAISED BY OCC IN THE DISTRIBUTION RATE CASE	11
IV.	FIRSTENERGY'S SERVICE QUALITY	15
V.	THE DSI RIDER	17
	A. FirstEnergy's Proposed DSI Rider	17
	B. OCC's Analysis And Recommendation	18
	C. Reliability Targets and the DSI Rider	21
	D. CEI's Rear Lot Reduction Factor	25
	E. Capital Spending and the DSI Rider	31
VI.	CAPITAL IMPROVEMENT PROGRAM	36
VII.	OCC RECOMMENDATIONS	39

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 graduated from the University of Kentucky in 1973 with a Bachelor of Science degree in Electrical Engineering and from Morehead State University in 1987 with a Masters degree in Business Administration. I am also 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 experience in the electric utility industry working for Kentucky Utilities Company as an Electrical Engineer from 1973-1977, Kentucky Power Company as a Distribution Engineer and then as a Power Engineer from 1977-1985, and American Electric Power Service Corporation as a Project Management & Construction Engineer and then as a Cost Control Engineer from 1985-1995. I have spent the past twelve years in the public sector working for the City of Columbus and the State of Ohio. I started at the City of Columbus in 1996 as an electrical engineering plan examiner and then was promoted in 1997 to the position of Supervisor of the Plans Examination & Inspection Section of the

Building Services Department, a unit totaling approximately 85 employees comprised of architects, engineers and building inspectors. In 2002, I took a similar position with the Division of Industrial Compliance as the electrical engineering plans examiner for the State of Ohio.

Q3. HOW MANY YEARS OF EXPERIENCE DO YOU HAVE WORKING DIRECTLY IN THE ELECTRIC UTILITY INDUSTRY?

A3. I have over 22 years of experience working directly for investor-owned electric utility companies. For the first fifteen years, I worked extensively on the engineering, design, and construction of new electrical distribution systems as well as the analysis and resolution of distribution circuit performance and reliability problems such as circuit overloads and unbalanced phases. In addition to providing solutions and action programs to solve reliability problems, I was involved directly with the implementation of operation and maintenance procedures to correct items such as voltage flicker and momentary outages. During the following seven-year period, my responsibilities were expanded to also include the engineering, design, construction and maintenance activities associated with transmission lines and stations (69 kV and above) and power plant systems.

Q4. WHAT PORTIONS OF YOUR WORK EXPERIENCE ARE RELATED TO THE DELIVERY OF RELIABLE ELECTRIC SERVICE?

A4. All of my work experience, spanning more than thirty years and involving all facets of the electric utility industry, are either directly or indirectly related to the delivery of reliable electric service. Because electric transmission and distribution systems are designed to last many decades and because utility companies must "keep the lights on" in order to meet their obligation to serve their customers and to make a profit, reliable service is the fundamental guiding principle for all engineering activities.

Q5. WOULD YOU PLEASE PROVIDE SOME EXAMPLES OF YOUR WORK EXPERIENCE CONCENTRATING IN THE AREA OF ELECTRICAL DISTRIBUTION SYSTEMS?

A5. I have extensive experience in the engineering, design, and construction of underground distribution systems. This experience includes the construction of the underground network grid serving downtown Lexington, Kentucky as well as numerous underground residential distribution ("URD") systems for Kentucky Utilities ("KU") Company. I was considered to be KU's URD utility expert and was charged with responsibility of specifying equipment, creating a URD cable testing program, and recommending operation and maintenance policies and practices to company management. In the area of overhead distribution systems, I have performed as an engineer and as an engineering supervisor responsible for the design and construction of new lines and substations such as a 12kV to 34.5kV conversion project in Ashland, Kentucky. I have performed a variety of technical studies such as system capacity/overload studies and cold load pickup studies which are needed to properly operate and maintain distribution lines and substations. I have both performed and supervised the performance technical studies such as load flow analyses, voltage fluctuation studies, fault studies, and analyzed outage cause data to determine the adequacy of distribution facilities. Additionally, I have had direct oversight of numerous outage restoration activities during major storms as well as the supervision of routine pole and a line/equipment inspection programs. Lastly, I have been directly responsible for a vegetation management program which includes utility employed arborists and contract tree trimming crews.

Q6. DID ANY OF YOUR WORK EXPERIENCE IN THE NON-UTILITY PUBLIC SECTOR ALSO INVOLVE THE RELIABILITY OF ELECTRICAL DISTRIBUTION SYSTEMS?

A6. Yes, it did.

Q7. WOULD YOU PLEASE PROVIDE SOME EXAMPLES OF THIS RELIABILITY-RELATED WORK EXPERIENCE?

A7. While working for both the City of Columbus and the State of Ohio, I reviewed and approved plans for electrical distribution systems for very large industrial customers, universities, penitentiaries, and other public institutions who owned their own electrical distribution facilities. I analyzed these entities' plans for compliance with the structural and electrical requirements of the Ohio Building Code ("OBC") which are the minimum standards for new construction. The projects which I reviewed included overhead and underground lines, substations, transformers, voltage regulators, relays, switches, circuit breakers, capacitors, reclosers, and a variety of other equipment which was very similar to that installed by electric utility companies. In addition, I continued to analyze outage report data and one-line circuit diagrams of different electric utility companies to evaluate their service reliability. This information was provided by the electric utility company to one of the large entities mentioned above (i.e. Ohio University) who owned their own distribution facilities. This analysis was necessary to determine if and when a second source of emergency power (such as an emergency generator or a second feed from the utility) was required by the OBC for a high risk facility such as a high-rise apartment building or a hospital. The standard for reliability contained in the OBC is extremely high because these high-risk facilities contain life safety systems such as emergency lighting, sprinkler systems, fire alarms systems, smoke control systems, operating rooms, elevators, etc. An example of this high standard would be a hospital which was served by a circuit with a reliability measure known as Customer Average Interruption Duration Index ("CAIDI") as low as 90 minutes, but would still be required to install an emergency power system.

Q8. ARE THERE ANY OTHER AREAS OF YOUR WORK EXPERIENCE WHICH ARE RELEVANT TO THIS PROCEEDING?

A8. Yes there are. First, while working for the City of Columbus, I was involved in the review and approval of site plans for large developments of residential and commercial property. This included the coordination of installation of the City's utility infrastructure for sewer, water, and storm water as well as electric and gas utilities. Through this review and approval process, I gained extensive knowledge of the pros and cons of both "rear lot" and "front lot" installation of utility infrastructure. This experience is relevant to the FirstEnergy Companies' witness Schneider's request for a "Rear Lot Reduction Factor" for CEI's SAIDI ("System Average Interruption Duration Index") calculation. Secondly, while working for American Electric Power Service Corporation, I was responsible for providing cost/benefit analysis and scheduling of large capital projects such as those proposed by the FirstEnergy Companies to enhance service reliability. This experience is relevant to the request for a Delivery Service Improvement Rider ("DSI Rider").

Q9. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A9. Yes. I testified in the FirstEnergy Distribution Rate Case, Case No. 07-551-EL-AIR, ("Distribution Rate Case") on behalf of the OCC. That testimony addressed the reliability-related policies and practices that are applied to the distribution systems of the FirstEnergy electric distribution companies.

Q10. WHAT WERE OCC'S RECOMMENDATIONS IN THE DISTRIBUTION RATE CASE RELATIVE TO SERVICE RELIABILITY AND COMPLIANCE WITH ESSS RULES?

A10. OCC made four recommendations related to service reliability and compliance with the PUCO's Electric Service and Safety Standards ("ESSS") that may be found on pages 29-30 in my testimony in the Distribution Rate Case:

1. Due to the problems associated with the Companies' recordkeeping systems, OCC recommended that the Commission require FirstEnergy Companies to use a minimum data retention period of five years.
2. Due to the performance of the FirstEnergy Companies, and particularly that of CEI, in not meeting its service reliability targets and due to problems documented in the Distribution Rate Case Staff Reports concerning the Companies' vegetation management program, OCC recommended the Commission require the Companies implement a performance-based vegetation management program which also addresses problems caused by trees outside the distribution right-of-way.
3. Due to the performance of the FirstEnergy Companies, and particularly that of CEI, in not meeting its service reliability targets, OCC recommended the Commission reflect that under-performance in the allowed rate of return, as addressed in the direct testimony of OCC witness Aster Adams.
4. Due to the problems associated with the FirstEnergy Companies service reliability programs, OCC recommended the Commission use its authority, pursuant to Ohio Revised Code 4905.26, to investigate the sufficiency and adequacy of the FirstEnergy Companies' service quality and to hold a hearing regarding that service quality.

II. PURPOSE OF TESTIMONY

Q11. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THE CURRENT PROCEEDING?

A11. 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 (the Cleveland Electric Illuminating Company ("CEI"), Ohio Edison ("OE"), and Toledo Edison ("TE") (collectively, "FirstEnergy Companies" or "Companies")). My testimony will specifically address the portions of the FirstEnergy Companies' Electric Security Plan ("ESP") Application which are related to the electric service reliability performance of their distribution systems. Because the Companies' propose to resolve their pending Distribution Rate Case in their ESP, my testimony will also include OCC's reliability-related recommendations from that distribution rate case. In addition, my testimony will address OCC's position concerning the Companies' proposals in their ESP Application to:

- Implement a DSI Rider,
- Increase or decrease the DSI rider based on the Companies' SAIDI performance indices, and
- Commit over $1 billion to capital investment in their distribution system over five years, from 2009-2013.

Q12. WHAT INFORMATION HAVE YOU REVIEWED IN PREPARING YOUR TESTIMONY?

A12. In preparing my testimony I have reviewed the Company's ESP Application, the testimony of the FirstEnergy Companies' witnesses, responses to OCC's discovery, responses to discovery by other interveners, and responses to Staff data requests. In addition, I have reviewed the Companies' filings, testimony of Companies and PUCO Staff witnesses, responses to OCC's discovery, responses to Staff data requests and the Staff Reports of Investigation in the Distribution Rate Case. Also related to the distribution rate case, I have reviewed the 2007 Focused Assessment of the Cleveland Electric Illuminating Company conducted by UMS Group Inc. ("UMS Report").[1] The sections which I reviewed of the Staff Reports in the Distribution Rate Case were those portions of the three reports for the Companies' prepared by the Public Utilities Commission of Ohio Staff's Service Monitoring and Enforcement Department. Finally, I reviewed the proposed revisions to the ESSS Rules in Case No. 06-653-EL-ORD, which is currently before the Commission.

Q13. PLEASE DESCRIBE THE RECOMMENDATIONS OF THE UMS REPORT AS REFERENCED IN THE STAFF REPORT.

A13. The UMS Report recommended eight short-term actions it believed CEI must take to meet ESSS Rule 10 reliability targets by the end of year 2009:[2] These recommendations include, but are not limited to, an enhanced tree trimming program to address overhanging limbs and structurally weak trees on the feeder

[1] Attachment DWC-1

[2] CEI Staff Report at 77

backbone, a systematized process of determining when to mobilize personnel in anticipation of storms, and full implementation of partial restoration practices when initially servicing customer outages. The UMS recommendations also identified five long-term (i.e. 10-years following 2009) actions which included maintaining capital spending at the level currently planned for 2008 ($84.7 million) for a minimum of 5 years. Finally, the report cited twelve (12) additional recommendations which are identified as desirable but at a lower cost benefit relationship.

Q14. WHAT WAS STAFF'S POSITION ON THE UMS RECOMMENDATIONS?

Q14. Staff recommended 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 recommended that CEI seriously consider implementing the 12 other UMS recommendations and that CEI provide 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.[3]

[3] CEI Staff Report at 79

III. FIRSTENERGY HAS NOT ADDRESSED THE SERVICE QUALITY ISSUES RAISED BY OCC IN THE DISTRIBUTION RATE CASE.

Q15. AS A RESULT OF YOUR REVIEW IN THIS ESP PROCEEDING, HAS OCC CHANGED ITS POSITION CONCERNING A RECOMMENDED DATA RETENTION PERIOD OF FIVE YEARS?

A15. No. OCC has not changed its position. There has been no indication in the Companies' ESP Application, their testimony, or from any information obtained from discovery in this case which would indicate that the Companies intend to accept OCC's recommendation to retain records for five years. It should be further noted that there has been no indication that the Companies have implemented Staff's recommendation to retain tree trimming records for eight years (equivalent to two four-year tree-trimming cycles). However, the proposed revisions to the ESSS Rules pending before the Commission appears to clarify that the retention period for records at a minimum must match the same time period of the inspection program, i.e. a five-year inspection cycle requires records which span five years. According to the proposed rule for 4901:1-10-27 (E)(4), "Each electric utility and transmission owner shall maintain records sufficient to demonstrate compliance with its transmission and distribution facilities inspection, maintenance, repair, and replacement programs as required by this rule." Depending on the Commission decision of the proposed ESSS Rules, OCC's concerns with FirstEnergy's data retention may be partly resolved.

Q16. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED ITS RECOMMENDATION THAT THE COMPANIES IMPLEMENT AN ENHANCED VEGETATION MANAGEMENT PROGRAM ADDRESSING TREES LOCATED OUTSIDE THE RIGHT-OF-WAY?

A16. No. There has been no indication in the Companies' ESP Application or testimony which would indicate that the Companies intend to accept OCC's recommendation. However, the FirstEnergy Companies have added one enhancement to its vegetation management program whereby the Companies will endeavor to remove overhanging branches from the primary conductor to the sky. This was a badly needed improvement. However, even with this change, OCC still recommends that more enhancements are needed and has therefore not changed its position from the distribution rate case.

Q17. WHAT WERE SOME OF THE PROBLEMS WITH VEGETATION MANAGEMENT THAT WERE CITED IN THE DISTRIBUTION RATE CASE?

A17. Section 4901:1-10-27(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 in the Distribution Rate Case found that missing records and inaccurate data prevented full verification by 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 Staff's inability to verify FirstEnergy's use of the 4-year cycle, 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."[4] As a result, it was difficult for Staff to determine the specific time periods in which all applicable circuits were actually trimmed.

Q18. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED ITS RECOMMENDATION THAT THE COMMISSION LOWER THE COMPANIES' ALLOWED RATE OF RETURN IN DETERMING THE LEVEL OF DISTRIBUTION RATE INCREASE FOR THE COMPANIES?

A18. No. Neither the Companies' ESP Application nor testimony addresses the topic of their current or past performance in meeting reliability targets. In the Distribution Rate Case, OCC recommended that the Commission reflect the Company's under-performance in meeting its reliability targets by lowering the Companies' allowed rate of return. The downward adjustment in the rate of return was addressed in the direct testimony of OCC witness Aster Adams. OCC's position has remained unchanged on this issue.

[4] CEI Staff Report at 67, OE Staff Report at 65, TE Staff Report at 69.

Q19. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED IS POSITION RECOMMENDING THAT THE COMMISSION ORDER A SEPARATE HEARING CONCERNING FIRSTENERGY'S SERVICE QUALITY?

A19. No. Due to the depth and breadth of the problems associated with FirstEnergy's service reliability programs, OCC has recommended 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. Proposed changes to the ESSS rules may require the actual filing of an electric utility's reliability targets to the Commission in the future as opposed to merely submitting the targets for Staff's approval. A formal filing should provide a more open process which the OCC argued for in the Distribution Rate Case.

Also, even though I am not an attorney, it is my understanding that portions of Amended Substitute Senate Bill 221 ("SB 221") may also impact this issue since R.C. 4928.02 (E) states the policy of the state is to:

> Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of electric retail service and the development of performance standards and targets for service quality for all

consumers, including annual achievement reports written in plain language.

Even though the proposed ESSS rule changes would improve the process going forward, the OCC would still recommend a hearing. OCC bases its position on both the Companies' past performance in the area of service reliability and as a result of the recent service restoration issues across FirstEnergy's service territory in Ohio due to the windstorms caused by Hurricane Ike.

IV. FIRSTENERGY'S SERVICE QUALITY

Q20. DOES THE COMPANIES' ESP APPLICATION OR TESTIMONY ADDRESS ANY OF THE PROBLEMS RAISED IN THE DISTRIBUTION RATE CASE CONCERNING ITS SERVICE QUALITY?

A20. No. Neither the Companies' ESP Application nor testimony addresses these issues.

Q21. WHAT ARE THE COMPANIES' PROPOSALS IN ITS ESP APPLICATION WHICH DO ADDRESS THE COMPANIES' QUALITY OF SERVICE?

A21. Companies' witness Schneider's testimony addresses only the ESP proposals for: 1) the DSI Rider; 2) a SAIDI target adjustment and performance range; 3) a rear lot reduction factor for CEI's SAIDI; 4) a $1 billion five-year capital commitment; and, 5) a Smart Grid Study.

Q22. IN WHAT WAY DO THESE COMPANIES' PROPOSALS RELATE TO SERVICE RELIABILITY?

A22. By proposing a DSI rider and a five-year $1 billion capital commitment, the Companies seem to recognize the need to devote additional resources to reliability matters and to replace aging infrastructure. In their ESP, the Companies' propose that the reliability target for SAIDI be adjusted upward for CEI but remain unchanged for OE and TE. It should be noted here that an upward adjustment in SAIDI increases the duration time for an average outage and the target is therefore less stringent.

Also for CEI only, a rear lot reduction factor for calculating SAIDI is proposed. The Companies also propose a performance range for SAIDI which would be used to adjust the DSI Rider based on each Companies' actual annual SAIDI performance.

Q23. WHAT DOES THE COMPANIES' SAIDI TARGET REPRESENT?

A23. The term SAIDI stands for "System Average Interruption Duration Index." It is calculated by dividing the sum of all outage durations for a time period such as a year by the total number of customers served by the distribution system. The number is measured in either hours or minutes and represents the average outage duration per customer on the system. For example, a SAIDI of 120 minutes means that the average system customer can expect to be out of power for 120 minutes each year. If the target for SAIDI is increased, i.e. 150 minutes, it is less stringent while a decrease in the SAIDI target, i.e. 100 minutes, is more stringent.

V. THE DSI RIDER

A. FirstEnergy's Proposed DSI Rider

Q24. WHAT DOES FIRSTENERGY PROPOSE AS A DSI RIDER?

A24. As described by Mr. Schneider, the DSI Rider is a non-bypassable distribution charge equal, on average, to $0.0020 per kWh on a service rendered basis. He goes on to state that the Companies need the rider to ensure that they are in a position to devote appropriate resources to reliability matters.[5] Mr. Schneider reiterates this point by stating that a DSI Rider is needed to provide the Companies the financial wherewithal to remain healthy and capable of continuing their ongoing commitments to the energy delivery and customer service business.[6]

Q25. HOW DOES THE PROPOSED DSI RIDER WORK?

A25. The DSI Rider would be subject to an annual adjustment, either up or down, based on each individual Company's actual performance for the previous year. The DSI Rider would be adjusted whenever the actual performance falls outside of a predetermined "range of no change" for SAIDI performance. According to Section A.3.f of the Companies' ESP Application, the Companies' SAIDI targets shall be 120 minutes and the performance band or "range of no change" shall range from 90 minutes to 135 minutes. If the SAIDI performance for one of the Companies is higher than 135 minutes, then the DSI rider for that Company will be decreased consistent with the amounts in the proposed tariffs. If the SAIDI

[5] See FirstEnergy Witness Schneider Direct Testimony at page 5.

[6] Id. at page 4, lines 14-18.

performance is less than 90 minutes, then the DSI rider for that Company will be increased consistent with the amounts in the proposed tariffs. The annual adjustment either upward or downward as proposed shall not exceed 15% for any calendar year.

Q26. HOW DO THE COMPANIES PROPOSE TO LIMIT THE ADJUSTMENT OF THE DSI RIDER TO 15%?

A26. According to Section A.3.f of the Companies ESP Application, the annual adjustment, either upward or downward, will not exceed 15% of the average DSI Rider for all three Companies in the aggregate. However, the Application fails to explain how the 15% adjustment will continue to occur after the rider is set to zero in 2012 and 2013.

B. OCC's Analysis And Recommendation

Q27. WHAT IS OCC'S POSITION CONCERNING THE PROPOSED DSI RIDER?

A27. The Companies have provided no justification for the need of the DSI Rider. Unsupported statements in the Application and testimony are not adequate to properly analyze the Companies' request for the Rider. Consumers should not be required to pay for activities the Companies' may not undertake or which may not provide beneficial results.

Q28. DO THE COMPANIES HAVE SPECIFIC AREAS OF NEED FOR WHICH THE FUNDS FROM THE DSI RIDER WILL BE TARGETED?

A28. According to the Companies' ESP Application, at page 21, the DSI Rider will enable the Companies to manage the increasing costs of providing service, address the need to expend capital earlier, train new employees, replace aging infrastructure, and address the importance of reliability and the emergence of new technology such as the Smart Grid.

Q29. HAVE THE COMPANIES PRESENTED EVIDENCE THAT THE DSI RIDER IS NEEDED TO ENABLE THE COMPANIES TO MANAGE THE INCREASING COSTS OF PROVIDING SERVICE?

A29. No. The Companies, and especially Mr. Schneider, provide no analysis or details supporting the need for the DSI Rider. For example, the Companies do not identify which costs have increased nor do they identify the "price tag" for any of the above items.

Q30. IS THE COMPANIES' PROPOSED DSI RIDER FLAWED?

A30. Yes. Electric utility customers should not have to pay "extra" for an acceptable level of reliable service. As currently proposed, the Companies would collect additional revenue through the DSI rider whenever their SAIDI fell within a fairly large range of acceptable values.

Q31. SHOULD THE COMMISSION APPROVE THE PROPOSED DSI RIDER?

A31. No. CEI has only just begun implementing the improvements needed to meet its reliability targets (as recommended by UMS and Staff). Mr. Schneider reaffirms the capital spending commitment in the response to Staff data request 4 – 3 by stating ***BEGIN CONFIDENTIAL*** "(A)s part of the Companies ESP, the Companies have committed to the $84.7 million capital spending level for CEI for the next five years." ***END CONFIDENTIAL*** It is premature to judge the final impact that this level of capital spending will have on CEI's service reliability performance for at least another three years.

Q32. WHAT IS THE ANTICIPATED IMPACT ON FIRSTENERGY'S RELIABILITY PERFORMANCE IF THE DSI RIDER IS NOT APPROVED?

A32. According to the response to Staff data request 4-24, ***BEGIN CONFIDENTIAL***no analysis has been completed by the Companies and thus they have not attempted to quantify the impact on reliability if the DSI Rider is not approved.[7]***END CONFIDENTIAL***

Q33. IS THE CONCEPT OF TYING RATE ADJUSTMENTS TO A COMPANY'S SERVICE RELIABILITY COMMONLY ACCEPTED?

A33. No. I know of only one other jurisdiction which has this type of rate. Since 1986, Mississippi Power Company ("MPCo") has operated under a Performance Evaluation Plan Rate Schedule ("PEP-4"). Unlike the DSI rider, which is tied only to the utility's SAIDI performance, the PEP-4 rate is determined by three different factors which are designed to provide the most value to customers – low price, high service reliability, and high customer satisfaction. The tariff also

[7] See response to Staff data request 4 – 24 (Attachment DWC-2).

establishes a "range of no change" for each factor. Annually MPCo's rates may go up, go down, or remain unchanged depending on their performance. Since the PEP-4 rate is based on price as well as service reliability, MPCo is not only motivated to improve service reliability but is also incented to lower their price by achieving cost savings though innovation and operating efficiencies.

Q34. WOULD OCC BE OPPOSED TO THE CONCEPT OF REWARDING THE COMPANIES FOR EXEMPLIARY PERFORMANCE?

A34. OCC would be open to a discussion which considers such a concept.

C. Reliability Targets and the DSI Rider

Q35. WHAT ARE THE COMPANIES' RELIABILITY TARGETS AND WHAT HAS BEEN THEIR RELIABILITY PERFORMANCE OVER THE PAST SEVERAL YEARS?

A35. ***BEGIN CONFIDENTIAL***The targets for CAIDI since the year 2000 have been 100 minutes for TE, 95 minutes for CEI, and 95 minutes for OE. For the years 2000-2007, TE has missed its target twice, CEI has missed its target every year, and OE has missed its target essentially once. The targets for SAIFI since the year 2000 have been 1.20 for TE, 1.00 for CEI, and 1.25 for OE. For the years 2000-2007, TE has missed its target once, CEI has missed its target five times, and OE has missed its target five times.[8] ***END CONFIDENTIAL***

[8] See response to OCC Interrogatory No. 27 (Attachment DWC-3)

Q36. IF THE COMISSION WERE TO ALLOW A DSI RIDER, DO YOU AGREE WITH THE USE OF SAIDI AS THE SINGLE RELIABILITY INDEX TO ADJUST THE DSI RIDER?

A36. First, any discussion of the use of SAIDI for adjusting the proposed DSI rider must be kept distinct and separate from the Companies' requirements to set performance targets for CAIDI and SAIFI and reporting their performance as required by the ESSS rules. Relative to the proposed DSI Rider, I would not be opposed to the use of only SAIDI for adjustment of the proposed rider. However, relative to the requirements of the ESSS rules, I believe both CAIDI and SAIFI continue to provide valuable and useful information and must be retained by the Commission as measures of the Companies' reliability performance. It is important for the Companies to report on both the duration *and* frequency of outages.

Q37. HOW DO EACH OF THE COMPANIES' CURRENT SAIDI PERFORMANCE TARGETS COMPARE TO THE TARGETS PROPOSED IN THE ESP?

A37. ***BEGIN CONFIDENTIAL***OE and TE currently have a SAIDI target of 120 minutes and CEI has a SAIDI target of 95 minutes.[9] The Companies ESP proposes the same SAIDI target for all three Companies. They propose to keep the SAIDI target for OE and TE at the current 120 minute level and to raise the target for CEI to 120 minutes also.***END CONFIDENTIAL***

[9] See the response to OCC Interrogatory No. 27 (Attachment DWC-3).

Q38. HOW DOES THE COMPANIES' PAST SAIDI PERFORMANCE COMPARE TO THE PROPOSED 120 MINUTE TARGET IN THE DSI RIDER?

A38. ***BEGIN CONFIDENTIAL***For the years 2000-2007, the SAIDI for TE has ranged between 78 – 165 minutes and averaged 104 minutes. The SAIDI for CEI has ranged between 105 – 194 minutes and averaged 143 minutes. The SAIDI for OE has ranged between 91 – 157 minutes and averaged 116 minutes.[10]***END CONFIDENTIAL***

Q39. DURING THE PERIOD FROM 2000 – 2007, HAVE ANY OF THE COMPANIES' SAIDI PERFORMANCE GONE OVER THE UPPER LIMIT OF THE PROPOSED DSI RIDER SAIDI RANGE OF 135 MINUTES?

A39. ***BEGIN CONFIDENTIAL*** Yes, CEI has gone over the upper limit (i.e. greater than 135 minutes) a total of five times, TE has gone over twice, and OE has gone over only once in eight years. Under the proposed DSI rider, the same performance for an eight year period going forward would result in a total of eight downward adjustments (i.e. decreases) in the rider rate. ***END CONFIDENTIAL***

Q40. DURING THE PERIOD FROM 2000 – 2007, HAVE ANY OF THE COMPANIES' SAIDI PERFORMANCE GONE UNDER THE LOWER LIMIT OF THE PROPOSED DSI SAIDI RANGE OF 90 MINUTES?

---

[10] Id.

A40. ***BEGIN CONFIDENTIAL*** Yes, TE has gone under the lower limit (i.e. less than 90 minutes) of the range a total of four times. Under the proposed DSI rider, the same performance for an eight year period going forward will result in a total of four increases in the rider rate. ***END CONFIDENTIAL***

Q41. HAVE YOU PREPARED A TABLE SUMMARIZING THIS DATA?

A41. Yes. The table below provides a summary. ***BEGIN CONFIDENTIAL***

	SAIDI			CAIDI			SAIFI		
Year	TE	CEI	OE	TE	CEI	OE	TE	CEI	OE
2000	165.2	118.1	114.8	102.3	116.8	95.3	1.61	1.01	1.20
2001	139.6	105.2	90.7	120.0	106.0	77.7	1.16	0.97	1.17
2002	87.7	145.8	109.4	84.4	153.8	73.4	1.04	0.95	1.49
2003	89.0	152.8	109.9	89.9	124.0	85.4	0.99	1.26	1.29
2004	91.1	153.2	116.1	99.4	126.8	82.6	0.92	1.21	1.41
2005	98.6	194.3	157.4	88.8	113.7	101.3	1.11	1.71	1.55
2006	78.3	150.6	127.8	86.3	125.0	89.0	0.91	1.20	1.44
2007	86.7	125.2	100.5	94.0	106.5	98.7	0.92	1.18	1.13

d. The table below contains the Companies SAIDI, CAIDI, and SAIFI target values for the years 2000-2007.

<table>
<tr><th></th><th colspan="3">SAIDI</th><th colspan="3">CAIDI</th><th colspan="3">SAIFI</th></tr>
<tr><th>Year</th><th>TE</th><th>CEI</th><th>OE</th><th>TE</th><th>CEI</th><th>OE</th><th>TE</th><th>CEI</th><th>OE</th></tr>
<tr><td>2000</td><td rowspan="8">120</td><td rowspan="8">95</td><td rowspan="8">120</td><td rowspan="8">100</td><td rowspan="8">95</td><td rowspan="8">95</td><td rowspan="8">1.20</td><td rowspan="8">1.00</td><td rowspan="8">1.25</td></tr>
<tr><td>2001</td></tr>
<tr><td>2002</td></tr>
<tr><td>2003</td></tr>
<tr><td>2004</td></tr>
<tr><td>2005</td></tr>
<tr><td>2006</td></tr>
<tr><td>2007</td></tr>
</table>

END CONFIDENTIAL

Q42. WHAT IS THE COMPANIES' JUSTIFICATION FOR ADJUSTING CEI'S SAIDI TARGET UPWARD FROM 95 TO 120 MINUTES?

A42. According to page 6 of Mr. Schneider's testimony, the 120 minutes represents the optimal reliability performance for CEI to balance service reliability and costs and on page 8 he states that it represents second quartile performance based on IEEE performance measures.

Q43. IS THE PROPOSED TARGET OF 120 MINUTES FOR SAIDI THE OPTIMAL RELIABILITY PERFORMANCE FOR CEI?

A43. I do not know since Mr. Schneider's testimony does not provide an explanation as to why 120 minutes provides the optimal balance between reliability performance and costs.

D. CEI's Rear Lot Reduction Factor

Q44. HAVE THE COMPANIES PROPOSED ANY OTHER ADJUSTMENTS TO THE SAIDI CALCULATION THEY WOULD USE FOR THE DSI RIDER?

A44. Yes, the Companies have proposed a Rear Lot Reduction Factor ("RLRF") for CEI only.

Q45. WHY IS FIRSTENERGY PROPOSING A REAR LOT REDUCTION FACTOR AND HOW WOULD IT WORK?

A45. The Companies contend that CEI's service area geography makes it extremely difficult to restore power quickly due to the large number of rear lot facilities. Mr. Schneider states that service restoration times are longer for these facilities because of obstructions located on the rear lots such as trees, fences, and garages.[11] The Companies also contend that this requires the utility to manually

[11] Schneider testimony at 7.

haul poles and equipment to such sites instead of using trucks. When calculating SAIDI for adjusting the proposed DSI rider, the Companies propose that a fifty percent reduction in the outage minutes for any of CEI's circuits where greater than one half of the customers are served by rear lot facilities be applied.

Q46. WHAT IS THE COMPANIES' BASIS FOR THE PROPOSED FIFTY PERCENT REDUCTION IN CUSTOMER OUTAGE MINUTES FOR CIRCUITS WITH A MAJORITY OF REAR LOT FACILITIES?

A46. In discovery the Companies state ***BEGIN CONFIDENTIAL*** "(T)he Rear Lot Reduction Factor was calculated based on the fundamental fact CEI experiences significant issues associated with crews being able to restore service timely to customers served on rear lot circuits based on number of customers and the need to manually haul poles and other equipment to such sites as opposed to using trucks." The Companies also provided a simple analysis which compared the difference in restoration times between circuits with rear lot and front lot construction. The analysis compared outage data from 2003 – 2007 and calculated the average time for restoring service for rear lot facilities was 50% greater than front lot facilities.[12] ***END CONFIDENTIAL***

Q47. WHAT IS YOUR EVALUATION OF THE COMPANIES' ANALYSIS?

A47. The Companies' analysis lacks the detail to properly evaluate the proposed 50% reduction factor. While restoration times may be shorter for front lot facilities due

[12] See response to Staff data request 4 - 32 (Attachment DWC-2).

to the use of bucket trucks, this certainly is not always true and is an oversimplification of the rear lot issue. For example, some of the rear lot construction may actually be underground facilities and therefore the need to manually haul poles to make repairs is not a factor. Also, some areas have alleyways, especially in older subdivisions and cities, located on the rear lot side which allows access for the Companies' trucks.

Furthermore, just as with rear lots, not all front lot facilities are accessible to trucks because the service poles needing repair are located on either side of the property. Also like rear lot construction, there are obstructions on the front side such as curbs, hydrants, parked vehicles, and fences which may impede the use of trucks. These situations will require line technicians to climb the poles at either location making the repair time the same.

In addition, the time differential between front lot and rear lot restoration is dependent upon the outage cause. For example, the time required for replacing a small piece of equipment such as a line fuse or a cutout on rear a lot circuit is not significantly greater than that required for a front lot circuit. The time differential may be greater, however, if large and/or heavy items such as poles and transformers are required for the repair job. Mr. Schneider states that these items must be manually hauled to the repair site. However, he does not consider the possibility of utilizing small portable hauling equipment such as an EZ Hauler pole trailer to haul heavy items to the rear lot site.

Q48. IF YOU AGREE THAT SOME REAR LOT REPAIR WORK MAY TAKE MORE TIME MORE TIME THAN FRONT LOT WORK, WHY DO YOU DISAGREE WITH THE NEED FOR THE RLRF?

A48. First of all, the Companies are proposing to increase CEI's SAIDI from 95 minutes to 120 minutes, a 26% increase, and the proposed DSI rider is not reduced until its SAIDI reaches 135 minutes. Thus, not only is CEI's SAIDI target changed (made easier to achieve), the outage minutes for many of its circuits will be reduced by 50% with the RLRF. In addition, the proposed change in the target and the application of the RLRF would also affect the Companies ESSS reporting and reliability requirements. This is not acceptable. I believe that this 26% increase in CEI's ESSS targets compensates for any problems associated with restoration times for rear lot construction. In addition, I believe that merely granting an adjustment to the SAIDI calculation does not incent the Companies to pursue real solutions to solve the problems associated with the restoration times required for rear lot construction. Rather, it may serve to mask or downplay a problem which needs to be addressed. In the end, it will not change the fact that CEI's customers on an RLRF circuit can actually be out of service for 240 minutes even though only 120 minutes will be reported by the Company.

Q49. HOW MANY OF CEI'S DISTRIBUTION CIRCUITS HAVE MORE THAN HALF OF THE CUSTOMERS SERVED BY REAR LOT FACILITIES?

A49. According to FirstEnergy's response to Staff data request 4-32, there are a total of ***BEGIN CONFIDENTIAL***1,086 distribution circuits in CEI and

339***END CONFIDENTIAL***of those have a majority of the residential customers being served by rear lot construction.[13]

Q50. WHAT IS THE POTENTIAL EFFECT THAT THE RLRF COULD HAVE ON CEI'S SAIDI PERFORMANCE IF APPLIED TO HISTORICAL DATA?

A50. The SAIDI minutes for CEI with rear lot reduction factor applied to actual data for 2003 – 2007 would result in adjusted SAIDI values ranging between ***BEGIN CONFIDENTIAL*** 99 – 161 minutes, with an average of 130 minutes.[14] It should be noted that if CEI did maintain a 130 minute SAIDI, ***END CONFIDENTIAL*** the Company would not experience a reduction in its proposed DSI rider.

Q51. IF THE RLRF WERE APPLIED TO CEI'S PAST SAIDI PERFORMANCE, HOW OFTEN WOULD CEI HAVE GONE OVER THE UPPER LIMIT OF THE PROPOSED DSI SAIDI RANGE OF 135 MINUTES?

A51. The SAIDI for CEI would have gone over ***BEGIN CONFIDENTIAL***135 minutes in 2003 (139 minutes) and 2005 (161 minutes) - twice during the five year period between 2003 and 2007.[15] ***END CONFIDENTIAL***

---

[13] See response to Staff data request 4 – 32 (Attachment DWC-2).

[14] See the response to OCC Interrogatory 28 (see Attachment DWC-4).

[15] Id.

Q52. WHAT IS YOUR CONCLUSION CONCERNING THE COMPANIES' PROPOSED REAR LOT REDUCTION FACTOR?

A52. The Commission should reject the Companies' proposal for the RLRF. I believe that granting an adjustment to the SAIDI calculation does not provide the proper incentive to the Companies to pursue more proactive, innovative, and more cost effective solutions to the rear lot issue. Further, the proposed increase in the SAIDI target for CEI to 120 minutes will mitigate potential impact due to rear lot construction.

Q53. WHAT DO YOU MEAN BY MORE PROACTIVE AND INNOVATIVE APPROACHES TO SOLVE THE REAR LOT ISSUE?

A53. An example of a proactive approach would be for the Companies to intensify their existing inspection programs to identify potential problems with rear lot facilities, especially poles and transformers. Problems identified in this way could be repaired via planned outages during normal work hours, lowering the cost of labor and minimizing outage time and inconvenience to customers. An example of an innovative approach would include utilizing new technologies that can locate faulty equipment prior to failure (e.g. Exacter). Examples of industry best practices include enhanced vegetation management, replacing wood poles with lighter, easier to handle steel poles, and/or utilizing portable hauling equipment (e.g. EZ-Hauler) to haul heavy equipment such as poles and transformers to rear lot locations that are not accessible to trucks.

E. Capital Spending and the DSI Rider

Q54. IF THE DSI RIDER WERE NOT APPROVED BY THE COMMISSION IN THIS ESP CASE, WOULD THE FIRSTENERGY COMPANIES CHANGE HOW THEY DECIDE WHICH DISTRIBUTION CAPITAL PROJECTS TO IMPLEMENT?

A54. No. According to the Companies' answer to Staff data request 4-13, ***BEGIN CONFIDENTIAL***the decision-making process would not necessarily be different if the DSI Rider is not approved. The Companies go on to say that while not part of the $1 billion commitment, the DSI Rider may provide the financial wherewithal to invest in capital projects in excess of or different from that baseline commitment.[16] ***END CONFIDENTIAL***

Q55. WHAT IS THE RELATIONSHIP BETWEEN APPROVAL OF THE DSI RIDER AND CEI'S COMMITMENT IN CASE 07-551-EL-AIR TO MAINTAIN ITS CAPITAL SPENDING AT A MINIMUM LEVEL OF $84.7 MILLION FOR AT LEAST FIVE YEARS?

A55. According to the Companies, ***BEGIN CONFIDENTIAL***the DSI Rider and CEI's commitment to maintain capital spending at a minimum level of $84.7 million for five years are not directly linked. In the Companies' response to Staff data request 4-3, Mr. Schneider says that "In total, the Companies have committed to make capital investments in their distribution systems in the

[16] See response to Staff data request 4 – 13 (Attachment DWC-2).

aggregate of at least $1 billion, which includes the $84.7 million for the CEI system."[17] ***END CONFIDENTIAL***

Q56. WHAT IS THE RELATIONSHIP BETWEEN APPROVAL OF THE DSI RIDER AND THE COMPANIES' $1 BILLION CAPITAL COMMITMENT CONTAINED IN ITS ESP APPLICATION?

A56. The DSI Rider and the $1 billion capital commitment are separate items. According to Staff data request 4-13, the Company says that ***BEGIN CONFIDENTIAL***while not part of the $1 billion commitment, the DSI Rider may provide the financial wherewithal to invest in capital projects in excess of or different from that baseline commitment.[18] ***END CONFIDENTIAL*** I will discuss the $1 billion capital commitment in more detail later in my testimony.

Q57. WHAT IS THE ANTICIPATED IMPACT ON EACH OF THE FIRSTENERGY COMPANY'S RELIABILITY PERFORMANCE IF THE DSI RIDER IS NOT APPROVED?

A57. According to Staff data request 4-24, ***BEGIN CONFIDENTIAL***no specific analysis has been completed by the Companies and thus they have not attempted to quantify the impact on reliability if the DSI Rider is not approved. ***END CONFIDENTIAL***

[17] See response to Staff data request 4 – 3 (Attachment DWC-2)

[18] See response to Staff data request 4 – 13 (Attachment DWC-2)

Q58. WHAT IS THE ANTICIPATED IMPACT ON EACH OF THE FIRSTENERGY COMPANIES' O&M EXPENSES IF THE DSI RIDER IS NOT APPROVED?

A58. According to Staff data request 4-17, ***BEGIN CONFIDENTIAL***no specific analytic studies have been done to estimate the impact on O&M expenses in the event that the DSI Rider is not approved. ***END CONFIDENTIAL***

Q59. WHAT IS WRONG WITH THE FACT THAT THE COMPANIES HAVE DONE NO ANALYSES TO DETERMINE THE IMPACT THE DSI RIDER WILL HAVE ON THEIR RELIABILITY?

A59. The Companies appear not to have a clear-cut plan for the use of the revenues generated by the proposed DSI rider. Without such a plan, it is difficult to understand how the Companies can know what their cost will be, how much revenue that they will need to cover those costs, and how to prioritize their expenditures in order to maximize the use to of the funds. Without the identification of specific programs and projects with estimated costs and benefits, the rider does not have sufficient justification.

Q60. DO THE COMPANIES PROPOSE TO PROVIDE ASSURANCE THAT THE DSI RIDER REVENUES COLLECTED FROM CUSTOMERS ARE ACTUALLY SPENT ON THE PROJECTS AND EXPENSE CATAGORIES FOR WHICH THEY ARE INTENDED?

A60. No, the Companies have not committed to provide controls to make sure the rider revenues received from customers are spent on designated projects. According to Staff data request 4-21, ***BEGIN CONFIDENTIAL***the Companies state that the DSI Rider revenues have not been assigned project and expense categories, but rather such revenues will ensure the overall health and financial sustainability of the distribution system.[19] ***END CONFIDENTIAL***

Q61. IN YOUR OPINION, WHAT WILL BE THE OVERALL AFFECT OF THE COMPANIES' PROPOSED ANNUAL ADJUSTMENTS TO THE DSI RIDER?

A61. I would expect that the net effect of the proposed annual adjustments will be zero in most instances. Based on the historical data the Companies supplied in response to OCC INT-27, OE's SAIDI already falls consistently ***BEGIN CONFIDENTIAL***within the 90-135 minute range ***END CONFIDENTIAL***and therefore would be expected to seldom receive either an increase or decrease to the OE DSI Rider. The same is true for TE except for an occasional ***BEGIN CONFIDENTIAL***sub-90 minute ***END CONFIDENTIAL*** SAIDI performance and thus would receive an increase in their DSI rider. As I testified previously, I would expect the steady improvement in CEI's SAIDI to continue because of their recent commitment to capital spending and ***BEGIN CONFIDENTIAL***sub-135 minute ***END CONFIDENTIAL*** performance in the near term. Due to CEI's increased

[19] See response to Staff data request 4 -21 (Attachment DWC-2)

capital spending coupled with the proposed wide range of values for acceptable SAIDI performance, I anticipate at a minimum the Companies will have as many "winners as losers" and thus in the aggregate the proposed adjustments will have little net effect.

Q62. WHAT IS OCC'S RECOMMENDATION CONCERNING THE COMPANIES' PROPOSED DSI RIDER?

A62. The OCC recommends that the Commission reject the Companies' proposal to implement the DSI Rider. As proposed in the Companies' ESP Application, the Rider has not been justified on the basis of cost or need, the design of the rider is flawed, and the timing is premature. The Companies have loosely tied the need for the rider to areas of general concern such as rising material costs, accelerated replacement of aging infrastructure, training of new employees, and requirements for a future Smart Grid. However, there are no specific programs or projects identified by the Companies, no cost/benefit analysis, and no discussion of potential costs savings that could serve to offset the costs associated with the identified areas of concern. Even if some of the Companies' concerns are legitimate, there are no specified amounts designated for each area of concern, no controls planned for the expenditures, and thus no guarantee that the funds will be spent on the intended projects. In summary, the proposed Rider is not justified and should be rejected.

VI. CAPITAL IMPROVEMENT PROGRAM

Q63. HOW DO THE COMPANIES INTEND TO IMPROVE THEIR RELIABILITY PERFORMANCE UNDER THE ESP?

A63. One of the major components of the FirstEnergy Companies' ESP Application in this area is their commitment to capital expenditures. According to Mr. Schneider, the Companies commit to make capital investments in their energy delivery system of at least $1 billion from 2009 – 2013. He contends this commitment helps to ensure that sufficient capital is being spent to address distribution system improvements.[20]

Q64. WILL THIS $1 BILLION CAPITAL EXPENDITURE COMMITMENT BE FUNDED THROUGH THE DSI RIDER?

A64. No, the Company has stated that the DSI Rider and the $1 billion capital commitment are separate items. According to their response to Staff's data request, the Companies say that ***BEGIN CONFIDENTIAL*** while not part of the $1 billion commitment, the DSI Rider may provide the financial wherewithal to invest in capital projects in excess of or different from that baseline commitment.[21] ***END CONFIDENTIAL***

Q65. IS THE COMPANIES' FIVE-YEAR $1 BILLION CAPITAL PROGRAM IN ITS ESP A NEW COMMITMENT?

[20] Schneider Direct Testimony at page 10.

[21] See response to Staff data request 4 – 13 (Attachment DWC-2)

A65. Not entirely. The Companies had already made a partial commitment for CEI in the Distribution Rate Case. The Companies committed $84.7 million for five years or approximately $424 million of the $1 billion capital commitment.

Q66. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANIES' PROPOSED FIVE YEAR $1 BILLION CAPITAL COMMITMENT IN ITS ESP AND CEI'S COMMITMENT TO MAINTAIN ITS CAPITAL SPENDING AT A MINIMUM LEVEL OF $84.7 MILLION FOR AT LEAST FIVE YEARS?

A66. CEI's commitment to spend $84.7 million for five years is part of the record in the Distribution Rate Case and is based on the first long-term recommendation on page 32 of the UMS report. According to their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL***the $84.7 million is included in the $1 billion capital commitment and the implication to OE and TE will be to share in some portion of the aggregate amount of the $1 billion.[22] ***END CONFIDENTIAL***

Q67. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANIES' PROPOSED FIVE YEAR $1 BILLION CAPITAL COMMITMENT IN ITS ESP AND THEIR TOTAL CAPITAL EXPENDITURES FOR THE PREVIOUS FIVE YEAR PERIOD?

---

[22] See response to Staff data request 4 – 3 (Attachment DWC-2)

A67. Based on their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL***the total expenditures for the five year period between 2003 and 2007 were approximately $967,257,000. It should be noted that the $1 billion capital commitment represents approximately a 3.4% increase over the actual expenditures for the previous five years.[23] ***END CONFIDENTIAL***

Q68. HAVE THE COMPANIES ESTIMATED THE IMPACT THAT THE $1 BILLION CAPITAL EXPENDITURE COMMITMENT WILL HAVE ON THEIR SAIFI AND CAIDI PERFORMANCE?

A68. No. According to their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL*** the prediction of future reliability performance as measured by CAIDI or SAIFI is speculative.[24] ***END CONFIDENTIAL***

Q69. WHAT IS OCC'S RECOMMENDATION CONCERNING THE COMPANIES' COMMITMENT TO SPEND $1 BILLION ON CAPITAL IMPROVEMENTS OVER THE NEXT FIVE YEARS?

A69. The OCC believes that additional expenditures are and will continue to be needed to be reinvested in the Companies' distribution infrastructure. However, the total amount of capital expenditures needed to achieve and sustain achievement of reliability targets is an unknown quantity. OCC recommends that the

---

[23] See response to Staff data request 4 – 6 (Attachment DWC 2)

[24] See response to Staff data request 4 – 22 (Attachment DWC-2)

Commission continue to monitor the Companies' capital expenditures to ascertain that the Companies are staying true to their commitments to focus spending on reliability needs.

VII. OCC RECOMMENDATIONS

Q70. IN SUMMARY, WHAT ARE OCC'S RECOMMENDATIONS RELATED TO PROTECTING AND IMPROVING SERVICE RELIABILILTY FOR CUSTOMERS?

A70.
1. The Commission should adopt all of OCC's recommendations from the Companies' Distribution Rate Case.
2. The Commission should reject the Companies' proposal to implement the Delivery Service Improvement Rider and the Rear Lot Reduction Factor.
3. The Commission should continue to monitor the Companies' capital expenditures to ascertain that the Companies are staying true to their commitments to focus spending on reliability needs.

Q71. DOES THIS CONCLUDE YOUR TESTIMONY?

A71. Yes. However, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event the PUCO Staff fails to support the recommendations made in the Staff Report and/or changes positions made in the Staff Report.

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

TABLE OF CONTENTS

1.0	Executive Summary	10
1.1	Introduction	10
1.2	General Overview	11
1.3	Reliability Analysis (Focused on 2009 Performance Targets)	14
1.3.1	Reduce Customer Interruptions	14
1.3.2	Reduce Outage Duration	19
1.4	Long Term Assessment (10-Year Vision)	20
1.4.1	Capital Expenditures	20
1.4.2	Refurbishment and Replacement of Aging Infrastructure	23
1.4.3	Organization and Staffing	24
1.4.4	Asset Management	28
1.5	Summary of Recommendations	28
1.5.1	SAIFI Improvement Recommendations	30
1.5.2	CAIDI Improvement Recommendations	31
1.5.3	Long-Term Recommendations	31
1.6	About UMS Group	33
1.6.1	Jeffrey W. Cummings	33
1.6.2	Daniel E. O'Neill	33
1.6.3	James M. Seibert	33
2.0	Electric Infrastructure Review	35
2.1	Purpose	35
2.2	Overview of the FE/CEI Electric System	35
2.3	Scope and Approach	36
2.3.1	Line/Circuit Inspections	37
2.3.2	Substation Inspections	38
2.4	Results of the Assessment	39
2.4.1	Summary of Results	40
2.4.2	Adequacy of System Condition Records	43
2.4.3	Material Condition of the Assets	44
2.4.4	Reliability Impact	44
2.5	Inspection Checklists	45
3.0	Outage History and Cause Analysis	52
3.1	Purpose, Scope, and Approach	52

3.2	The Outage Database	52
3.3	Trends in Key Performance Statistics	53
3.4	Framing the Reliability Issues	55
3.4.1	Stage of Delivery Analyses	56
3.4.2	Opportunity Analysis	57
3.4.3	Causal Analysis	66
3.4.4	Outage Restoration	69
4.0	Reliability Improvement Framework	74
4.1	Purpose, Scope, and Approach	74
4.1.1	Reliability Improvement Framework	75
4.2	Standard Assessment Approach	77
4.2.1	Scope and Context	77
4.2.2	Current State Assessment	77
4.2.3	Recommendations	77
5.0	Service Interruption Assessment	79
5.1	Purpose, Scope, and Approach	79
5.2	Protect the Backbone	79
5.2.1	Scope and Context	79
5.2.2	Hardening the Backbone	79
5.2.3	Feeder Sectionalizing, Including Fusing and Installing Reclosers	86
5.2.4	13.2kV and 4kV Circuit Considerations for Protecting the Backbone	91
5.3	Non-Feeder Backbone Initiatives	92
5.3.1	Worst Performing Circuits (Rule 11)	92
5.3.2	Worst-Performing Devices (Repeat Offenders)	93
5.3.3	Underground Cable Replacement	94
5.3.4	Electric Service and Safety Standards (ESSS) Inspections (Rule No. 26)	96
5.4	Long-Term Approach	100
5.4.1	System Capacity and Overload Forecasting	100
5.4.2	Refurbishment and Replacement of Aging Infrastructure	106
5.5	Summary of Recommendations	107
6.0	Service Restoration Assessment	115
6.1	Purpose, Scope, and Approach	115
6.2	Service Restoration Process	115
6.3	Service Restoration Performance Overview	117

6.4	Service Restoration Performance Assessment	119
6.4.1	Mobilization	119
6.4.2	Workflow	125
6.4.3	Communication	127
6.5	Summary of Recommendations	128
7.0	Organization and Staffing Assessment	133
7.1	Purpose, Scope, and Approach	133
7.2	Overview of the CEI Organization Structure	134
7.3	Assessment of Organization and Staffing	137
7.3.1	Sustainable Workforce	137
7.3.2	Workforce Management	143
7.3.3	Reliability Culture	147
7.3	Summary of Recommendations	149
8.0	Capital Expenditure Assessment	154
8.1	Purpose, Scope, and Approach	154
8.2	Overall Capital Expenditure Levels	154
8.3	Reliability-Related Capital Investment	158
8.4	Capital Planning and Improvement Processes	160
8.5	Capital Processes Integrity	165
8.6	Asset Management Initiative	167
8.7	Summary of Recommendations	169
9.0	2005 ESS Rule 10 Action Plan Compliance Review	170
9.1	Purpose, Scope, and Approach for this Section	170
9.2	Provisions of the ESS 2005 Rule 10 Action Plan	170
9.3	CEI's Compliance ESS 2005 Rule 10 Action Plan	172
9.3.1	First Responder Program	172
9.3.2	Additional Shifts (Afternoon, etc.)	172
9.3.3	Management Review of Lockouts	173
9.3.4	Management Review of Inoperable Equipment	173
9.3.5	Management Monitoring of Weather	173
9.3.6	Overtime and Additional Staffing	173
9.3.7	Analysis of Instantaneous Trip of Relays	173
9.3.8	Installation of Fault Indicators	174
9.3.9	Isolating outages to reduce CMI (Single Phase Reclosers)	174
9.3.10	Large subtransmission supply outages (Sectionalizing)	174

9.3.11 Lengthy outages for a large number of customers (Bus Ties) 174
9.3.12 VSA circuit breaker failures 174
9.3.13 Reduce long outages (4kv Upgrade Work) 174
9.3.14 Cable failures (VLF Testing and Replacement 174
9.3.15 Large area subtransmission supply outages (Pole Replacement) 174
10.0 Appendix 177
10.1 RFP to Final Report Cross Reference 177
10.2 List of Data References 178
10.3 List of Cleveland Electric Illuminating Company Staff Interviews 181

LIST OF FIGURES

Figure 1-1 UMS Group's 3-Phased Diagnostic Process 10
Figure 1-2 Industry Context for CEI's SAIFI and CAIDI Targets 12
Figure 1-3 CEI 5-Year Reliability Performance 13
Figure 1-4 2006 SAIFI Stage of Delivery 14
Figure 1-5 Distribution SAIFI (By Number of Customers) 15
Figure 1-6 Key Causes of Distribution SAIFI 16
Figure 1-7 CEI Circuits without Reclosers 17
Figure 1-8 CEI Capital Spending vs. Similar Systems (1988-2006) 21
Figure 1-9 Critical Staffing Categories 25
Figure 1-10 CEI Employees by Age and Function 26
Figure 1-11 Workforce Management Assessment 27
Figure 1-12 Opportunities & Risks of First Energy's Asset Management Initiative 28
Figure 1-13 Reliability Impact and Cost Summary 29
Figure 2-1 First Energy Operating Company Territories 36
Figure 2-2 Listing of Inspected Lines and Circuits 37
Figure 2-3 Listing of Selected Substations 37
Figure 2-4 Lines / Circuits Inspection and Analysis Process 38
Figure 2-5 Substation Inspection and Analysis Process 39
Figure 2-6 Condition Records Review and Analysis Process 40
Figure 2-7 Lines/Circuits Inspection Results 41
Figure 2-8 Substation Inspection Results 41
Figure 2-9 Reliability Related Exceptions by Voltage Class 42
Figure 2-10 Reliability Related Exceptions by Inspection Date 42
Figure 2-11 Reliability Related Exception Analysis 43
Figure 3-1 Five Year Summary of Key Reliability Measures 54
Figure 3-2 Five Year Trend in Key Reliability Measures 54
Figure 3-3 CEI Reliability Performance Targets 55
Figure 3-4 2006 Storm Exception Impact 55
Figure 3-5 Reliability Analysis Framework 55
Figure 3-6 Trends in Non-Storm SAIFI Minutes by Subsystem 56
Figure 3-7 2006 SAIFI by Stage of Delivery 56
Figure 3-8 Mix of Outages by Outage Size 57
Figure 3-9 Breakdowns of Customer Interruptions by Outage Size 58

Figure 3-10 Breakdowns of Customer Minutes by Size of Outage 58
Figure 3-11 Five Year Impact of Lockouts 59
Figure 3-12 Impact of Lockouts by Voltage 59
Figure 3-13 Distribution SAIFI by Line District 60
Figure 3-14 Distribution CAIDI by Line District 60
Figure 3-15 Distribution SAIDI by Line District 61
Figure 3-16 Distribution SAIDI by Voltage Class 62
Figure 3-17 SAIFI-D for 13.2kV and 4kV System 62
Figure 3-18 Worst Performing 13.2kV Circuits 63
Figure 3-19 Worst Performing 4kv Circuits 65
Figure 3-20 Key Causes Of Distribution SAIFI 66
Figure 3-21 Line Failure Customer Interruptions Due To Lockouts 67
Figure 3-22 Storm Model 67
Figure 3-23 Equipment Failure Customer Interruptions Due To Lockouts 68
Figure 3-24 Trees/Non-Preventable Customer Interruptions Due To Lockouts 69
Figure 3-25 Highest Number of Outages Per Day (Top 35) 69
Figure 3-26 Highest Numbers of Outages per 5 Day Groupings 71
Figure 3-27 Number of Outages Drive Duration (2006) 72
Figure 3-28 Outage Duration by Hour of Day 73
Figure 4-1 Illustrative Reliability Improvement Initiatives 75
Figure 4-2 Typical Recommendation Table for Sections 5 Through 8 78
Figure 5-1 Example Clearance 81
Figure 5-2 U. S. Lightning Patterns 82
Figure 5-3 Typical Animal Contact 85
Figure 5-4 CEI Circuits Without Reclosers 88
Figure 5-5 U.S. Growth Trend 95
Figure 5-6 ESSS Inspection Summary 96
Figure 5-7 2006 ESSS Inspection Close-Out Activities 97
Figure 5-8 Lines/Circuits Inspection Summary of Results 97
Figure 5-9 Reliability Related Exceptions Analysis 98
Figure 5-10 Illustrative Pole Rot 98
Figure 5-11 Capacity Planning Stages 101
Figure 5-12 Customer Count and Growth Rate by District 102
Figure 6-1 Typical Outage Restoration Process 115
Figure 6-2 CEI CAIDI Performance – Non-Storm without Transmission 118

Figure 6-3 CEI Distribution Line CAIDI Performance 118
Figure 6-4 CEI District Demographic Information 119
Figure 6-5 CEI Storm Model 121
Figure 6-6 Outages Drive Duration 121
Figure 6-7 Overhead Lines Call-Out Response 123
Figure 6-8 Substation Call-Out Response 123
Figure 6-9 Outage Duration by Hour of the Day 124
Figure 7-1 Elements of the Organization and Staffing Assessment 133
Figure 7-2 CEI Service Territory 134
Figure 7-3 Customer Count and Growth Rate by District 135
Figure 7-4 Electric Infrastructure by District 135
Figure 7-5 Current CEI Organization Structure 136
Figure 7-6 Critical Staffing Categories 137
Figure 7-7 CEI Employees by Age and Function 138
Figure 7-8 Leadership/Management by Age and Function 138
Figure 7-9 Regional Dispatching Staff by Age and Experience 140
Figure 7-10 Distribution Line Staff by Age Category 141
Figure 7-11 Engineering Services Staff by Age Category 141
Figure 7-12 Substation Staff by Age Category 142
Figure 7-13 Relay Tester Staff by Age Category 142
Figure 7-14 Underground Network Staff by Age Category 143
Figure 7-15 Substation Préventive Maintenance Performance (2005-2006) 144
Figure 7-16 Distribution Lines Corrective Maintenance Performance 144
Figure 7-17 Distribution CAIDI by District 145
Figure 7-18 New Business 2006 Workload 146
Figure 7-19 CEI Employee/Contractor Mix 147
Figure 7-20 Workforce Management Assessment 147
Figure 7-21 Change Readiness Assessment 149
Figure 7-22 Current Attrition and Hiring Projections 151
Figure 7-23 Incremental Hiring Profile 151
Figure 8-1 Capital Spending Levels (1990-2006) 155
Figure 8-2 CEI Capital Spending vs. Similar Systems (1988-2006) 157
Figure 8-3 2006 CEI Capital Budget by Budget Category 158
Figure 8-4 2006 CEI Capital Budget – Reliability Reconciliation 159
Figure 8-5 2005 CEI Capital Budget by Budget Category 160

Figure 8-6 CEI Investment Reason Categories 163
Figure 8-7 Risk (Impact and Likelihood) Definition Standards 164
Figure 8-8 Typical Evolution of Asset Management Capabilities 166
Figure 8-9 Opportunities & Risks of First Energy's Asset Management Initiative 169
Figure 9-1 Exhibit A from FirstEnergy RFP 170
Figure 9-2 Summary of 2005 ESS Action Plan Compliance and Impact 175

1.0 Executive Summary

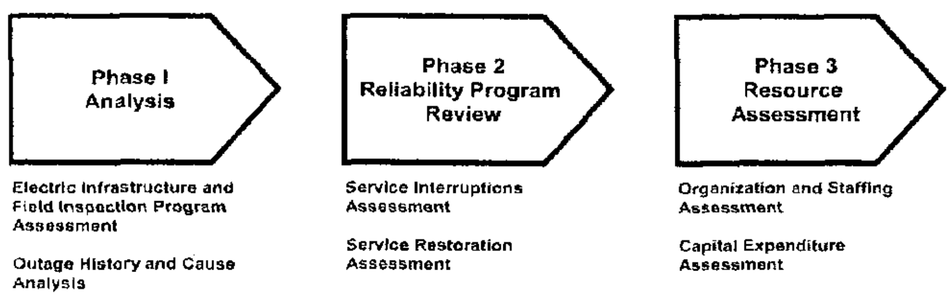
1.1 Introduction

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.

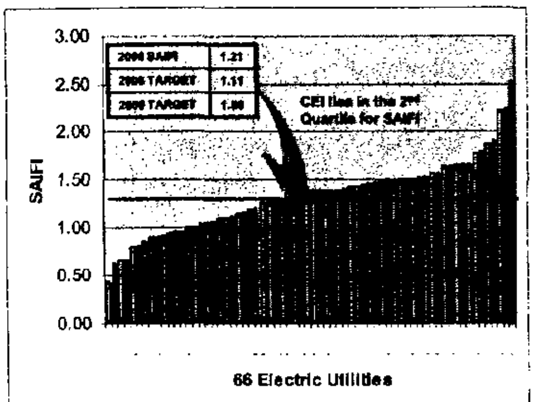
1.2 General Overview

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.

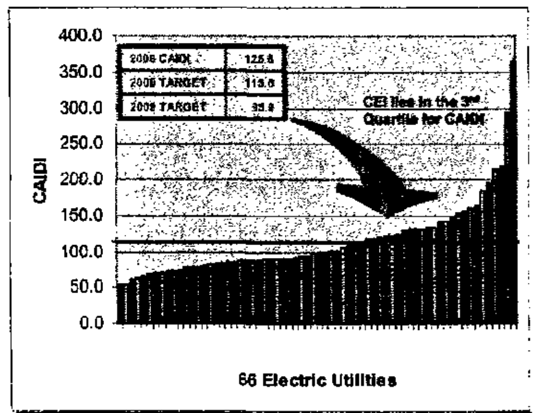
Although the results of this assessment are not uniformly positive in terms of performance or outcome, we believe that the evidence presented in this report shows that the Company has made and is continuing to make the necessary improvements in its procedures, processes, practices, spending levels and 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)

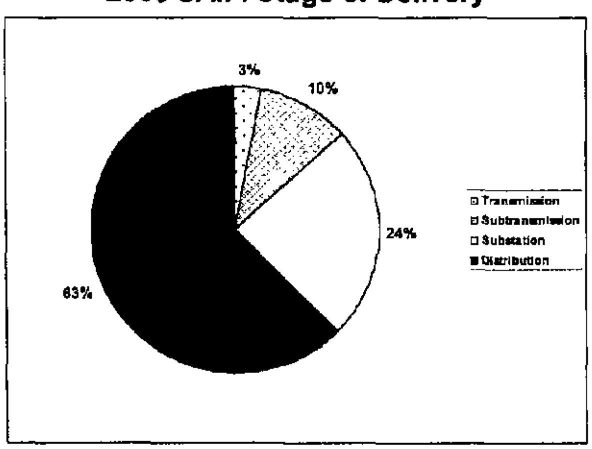
In establishing focus and direction to this analysis, we narrowed our view to "Non-Storm" events As a point of clarification, "Non-Storm" is synonymous with "Non-Major-Storm"; that is, while 'non-storm' excludes major storms that affect more than six percent of the Company's customers for a sustained 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



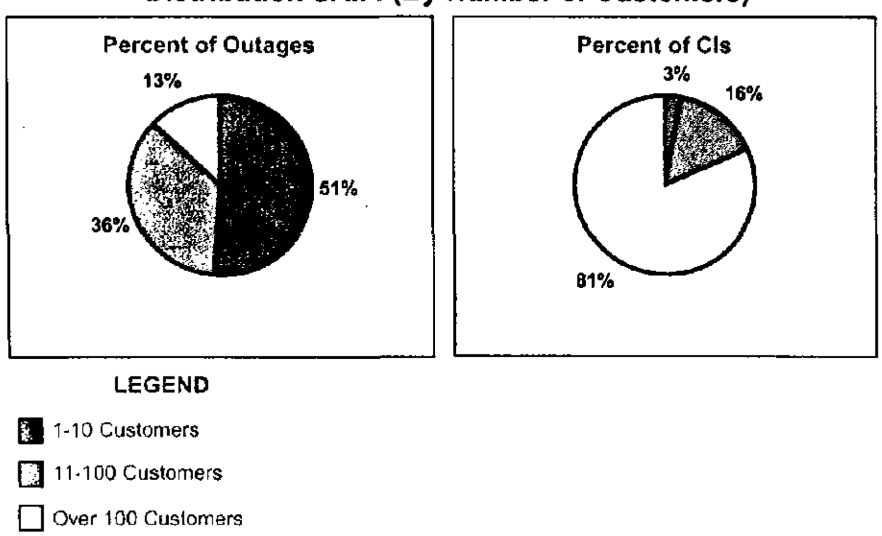
In reviewing the implications of the Stage of Delivery analysis (Figure 1-4), the following key points are summarized:

- 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) 1st or 2nd-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.

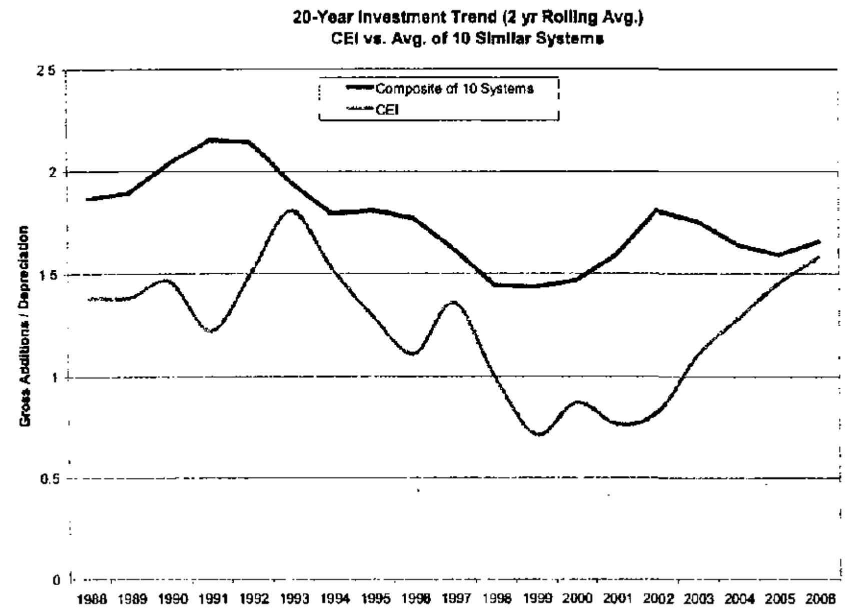
The key driver to realizing this vision is the amount of capital to be invested in the assets and then to properly allocate the capital in a manner that will yield the highest return in terms of improved performance. Therefore, the following discussion will first highlight the key points arrived at during 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 <u>always</u> 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 <u>counter</u> 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 2^{nd} 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.

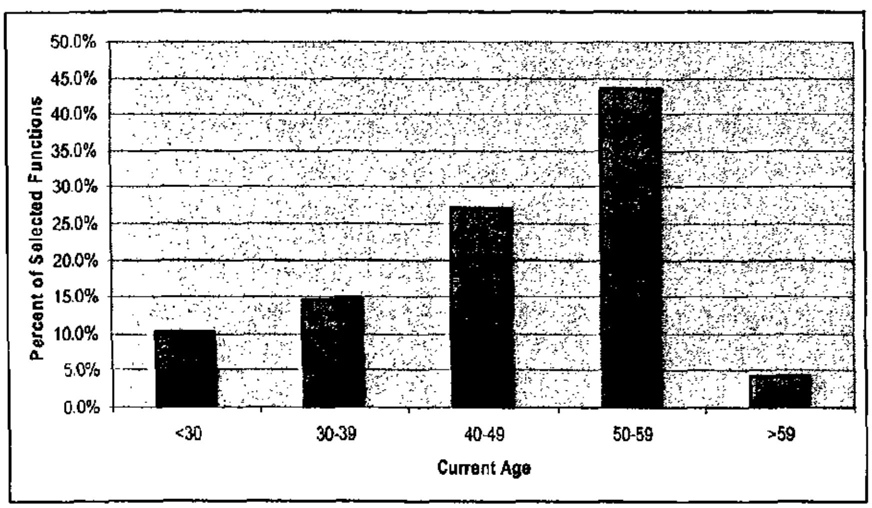
Aging Work Force

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

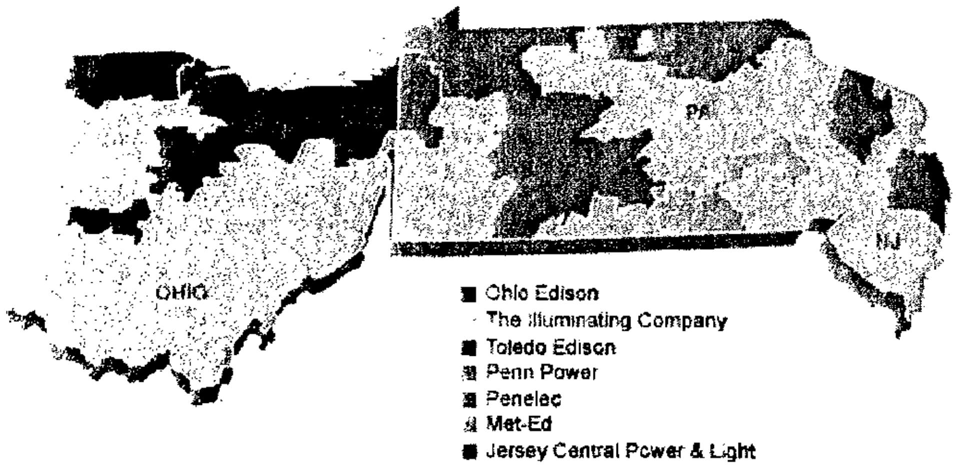
The purpose of this section of the report is to summarize our review of CEI's electric system infrastructure with a specific focus on its impact on reliability. Our approach was designed to satisfy three specific goals:

- ***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**

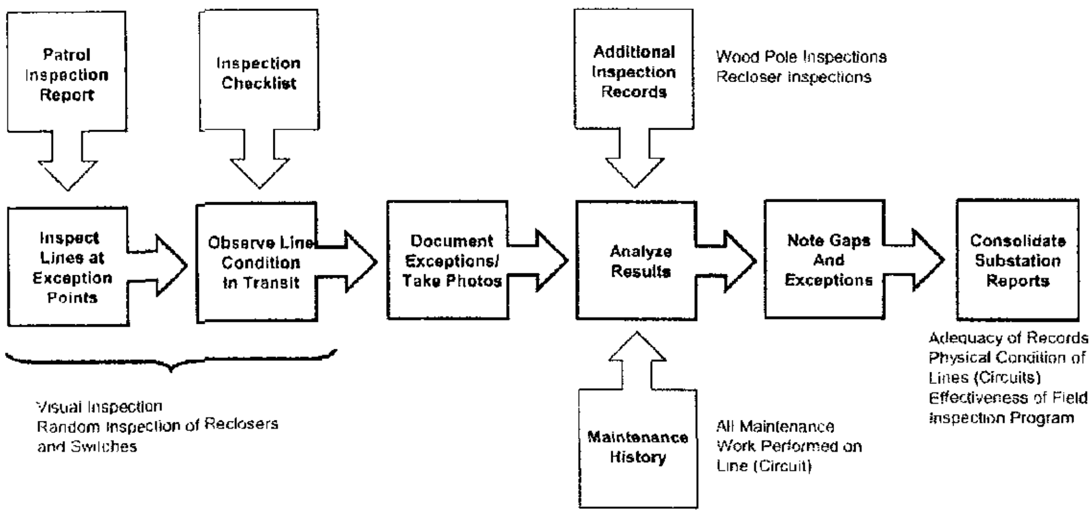
We conducted this inspection through a process that included standardized inspection checklists (refer to Section 2.6 for the format of these checklists) for both the Lines/Circuits and Substations inspections to enhance the accuracy and comparability of our results.

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



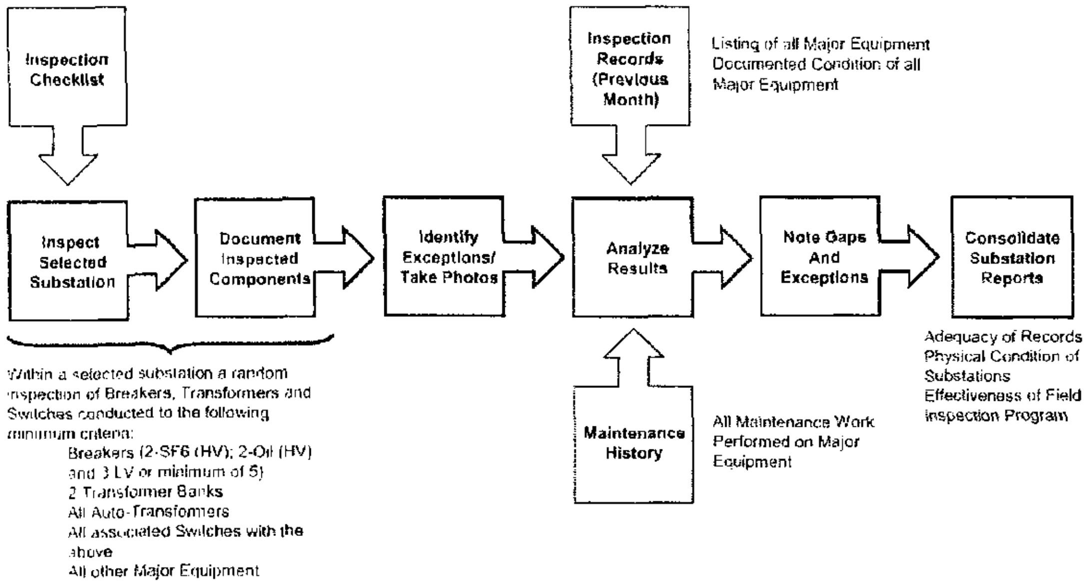
2.3.2 Substation Inspections

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



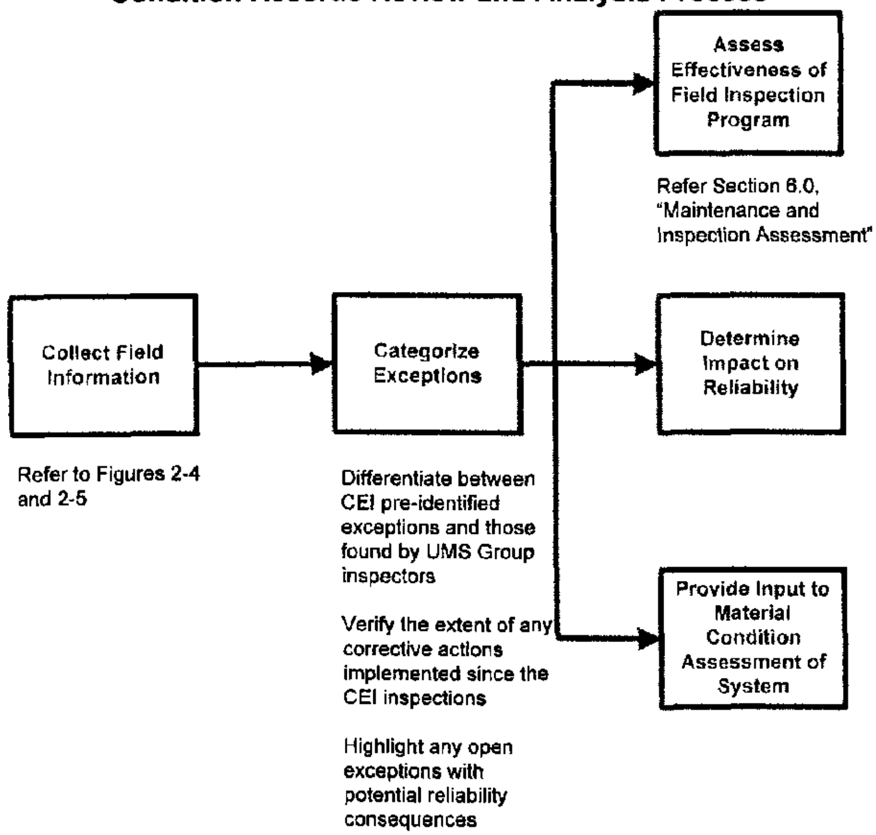
2.4 Results of the Assessment

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
	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	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	

Relay Inventory	Total Number	Type Relay	Last Tested Date
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 arrresters ok	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

Transformers

		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.

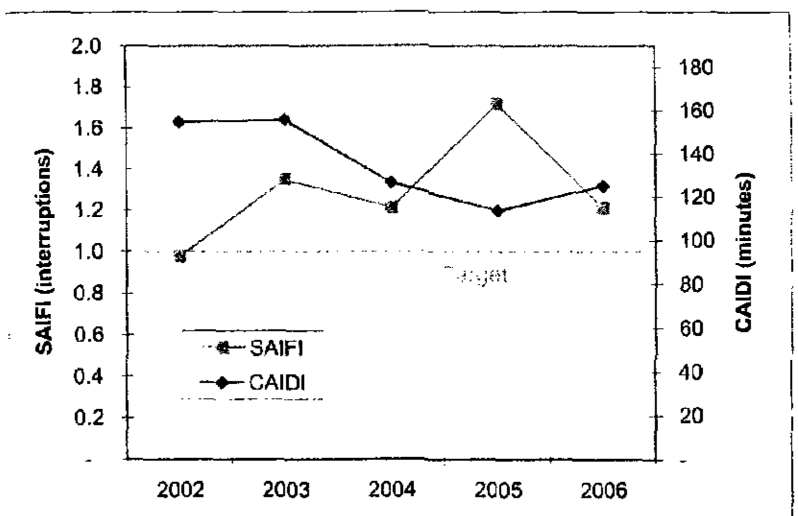
Figure 3-1
Five Year Summary of Key Reliability Measures

		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

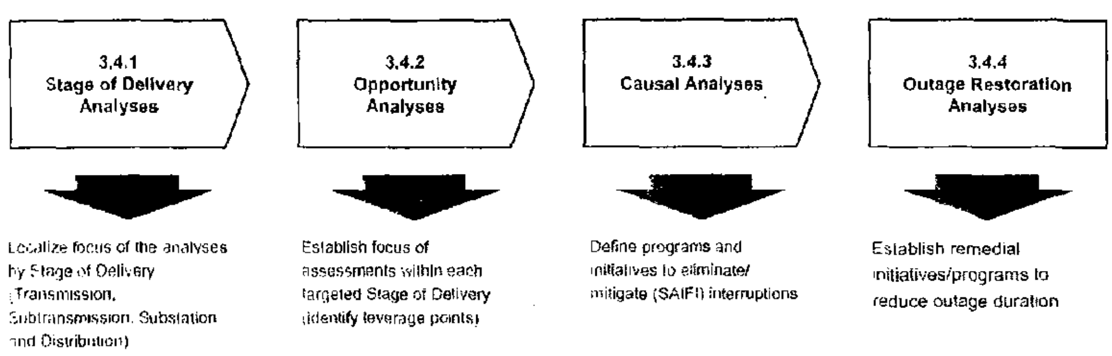
	CIs	CMIs	PCNT of Customers	Adjusted SAIFI	Adjusted CAIDI
Late Storm	39,266	11,096,490	5.4%	[redacted]	
Heat Storm	57,028	13,873,370	7.6%		
W/O Both	96,294	24,969,860	N/A	1.05	112.4

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).

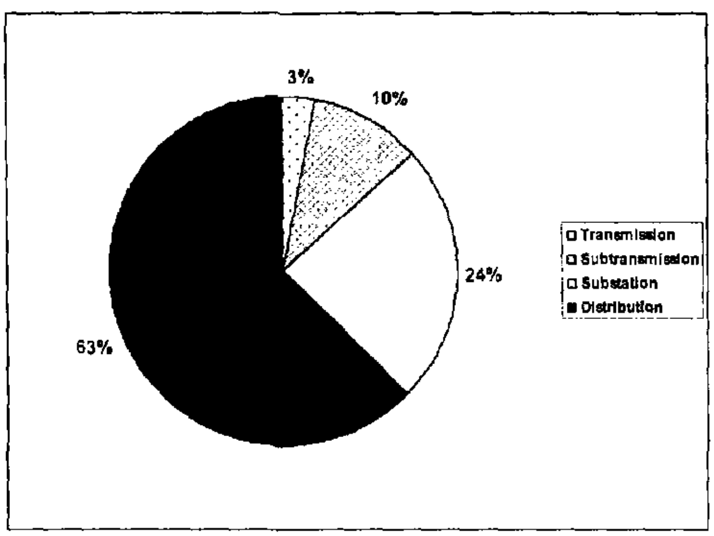
Figure 3-6 below shows a disaggregation of non-storm SAIFI performance by stage of delivery.

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

Number of Customers Impacted

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	96029	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.

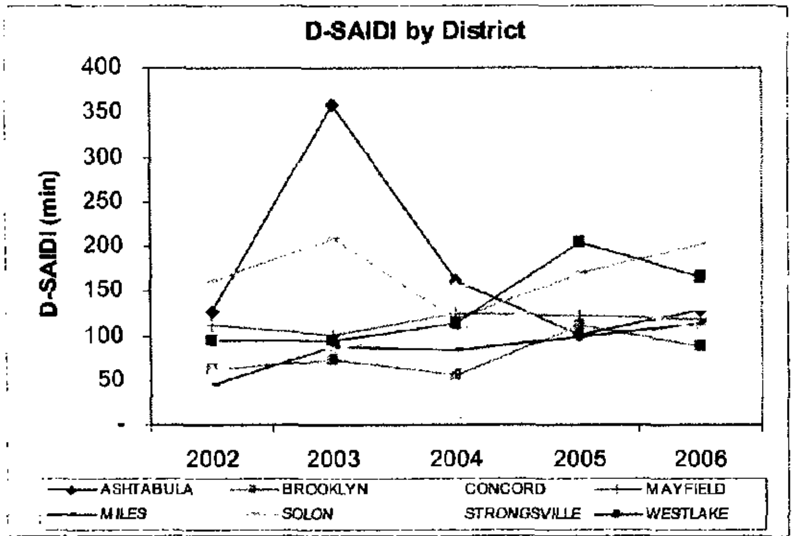
Figure 3-13
Distribution SAIFI by Line District

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.

<u>Voltage (4kV and 13.2kV)</u>

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.

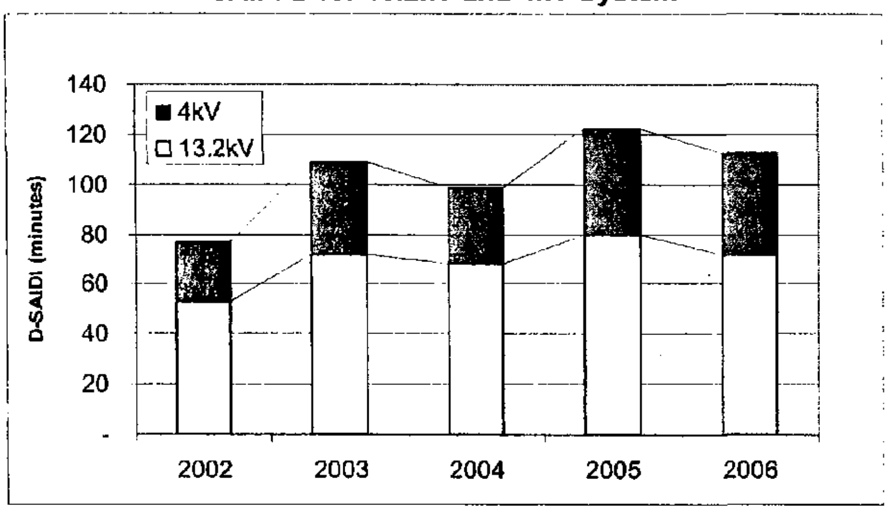
However, the number of customers served by the 13.2kV and 4kV is not proportionate to the number of circuits (over 60 percent of the customers are served from the 13.2kV). Consequently, the typical 4kV circuit is smaller than the typical 13.2kV circuit, not only in terms of serving fewer customers, but 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	7,548	34	222
0002	40218	91.95	13.78	105.73	87%	1,580	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	948,213	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	715,978	5,748	37	155
0001	40162	19.63	12.48	32.11	61%	4,048	126	705,945	3,323	44	76
0005	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	34.46	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	590,363	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	1.25	8.23	85%	1,371	167	569,750	3,365	6	561
0002	40103	19.28	13.50	32.78	59%	2,130	65	524,225	2,833	28	101
0004	40123	15.85	2.77	18.63	85%	3,153	169	508,910	2,910	26	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	Out ages	CI/Out
0008	40109	7.85	0.25	8.10	97%	1,461	180	1,241,988	4,195	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	1,655	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

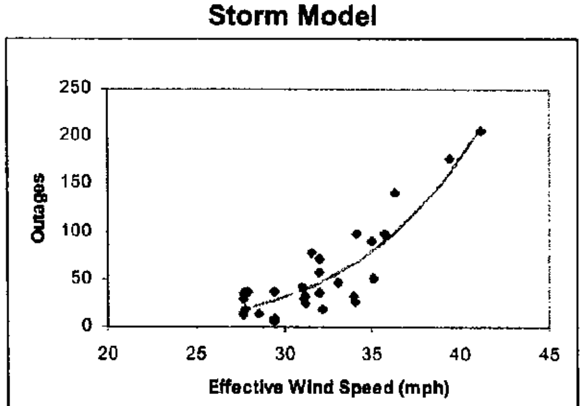
In further analyzing line failures, we have necessarily included wind and lightning (accounting for the change in coding between 2003 and 2006). Figure 3-21 below illustrates that for both voltages the trends are similar: Significant progress was made from 2003 and 2005 in reducing the number and percentage 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 10th, July 27th-28th, June 21st, July 20th and October 17th). 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 30th to August 2nd, 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 30th-31st, the temperature reached the high-80s and CEI experienced 87 outages on the 30th and 142 on the 31st (many of the ones on the 31st 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

<u>Number of Outages</u>

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

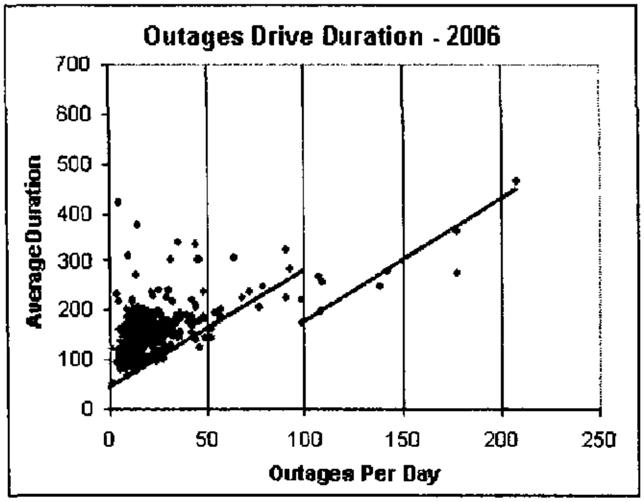
Worst Days	Outages Per Group	Outages Per Day	CI	CMI	CAIDI
1-5	878	176	97,439	21,375,012	219
6-10	566	113	99,385	19,118,196	192
11-15	441	88	54,838	9,438,469	172
16-20	353	71	50,630	6,664,292	132
21-25	287	57	42,894	5,435,507	127
26-30	243	49	23,024	2,327,437	101
31-35	225	45	17,230	2,033,455	118

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)



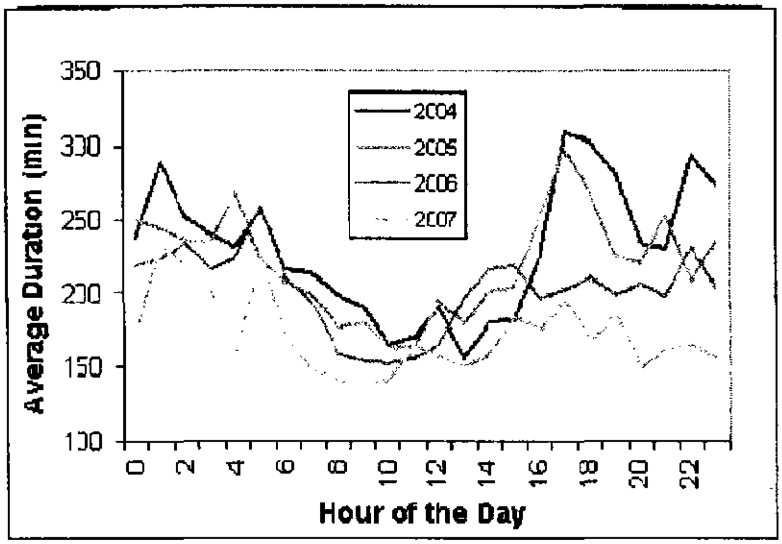
Timing of Outages

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.

Figure 5-1
Example Clearance

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 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.

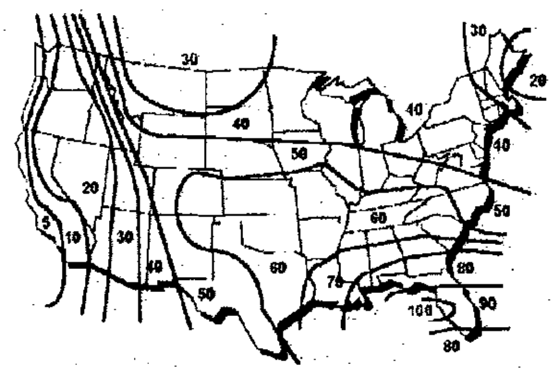
CEI should optimize and enhance its tree-trimming program (and already has started with its "Danger/Priority Tree Program") to target potential outages to the backbone caused by broken limb/fallen tree situations that can be identified in advance as cases of 'structural weakness'. Such a program should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

Installation of Reclosers

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 mitigation 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.

<u>Relaying/Over-Current Protection</u>

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 not 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.

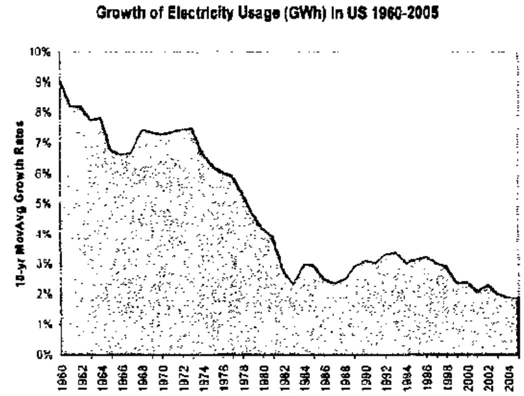
Note: This technology is available and already in use at CEI. FirstEnergy's PowerOn OMS data is used to map CEMI in the GIS View application. This provides a customer-level view of outage information and pinpoints worst performing devices.

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:

- 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.

Figure 5-5
U.S. Growth Trend



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	5998 Inspections
Pad-Mounted Equipment Internal Inspections	1066 Inspections	Met Goal: 1068 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	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
	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	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 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.

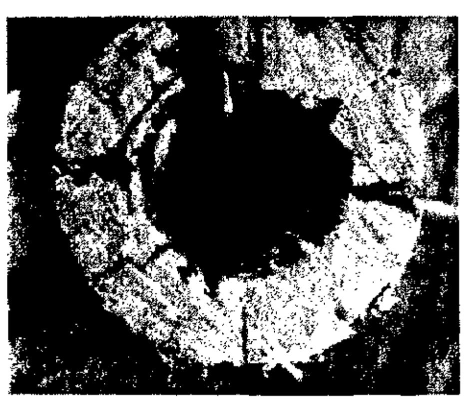
CEI needs to remain focused on improving its performance with respect to meeting the mandated ESSS Inspection requirements. And, every indication is that CEI Management is committed to making that happen. However, we do need to point out that any correlation between the exceptions noted in these inspections 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.

Distribution Pole Inspections and Replacement

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 hammerlike 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

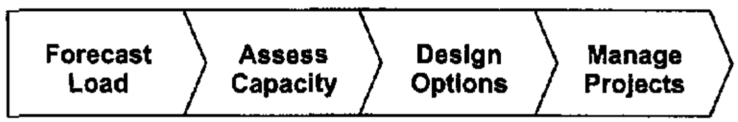
The purpose of this section is to review CEI's distribution load forecasting processes to determine if they are appropriate, and if adequate resources have been allocated to accommodate any growth. Our analysis includes a review of the forecast horizon, level of detail, accuracy and credibility of the 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.