Office of the Ohio Consumers' Counsel

Your Residential Utility Advocate

Janine L. Migden-Ostrander
Consumers' Counsel

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April 10, 2007

Ms. Renee Jenkins, Secretary
Public Utilities Commission of Ohio
Docketing Division
180 E. Broad St., 13th Floor
Columbus, Ohio 43215-3793

Re: Supplemented Testimony of Peter J. Lanzalotta in Case No. 06-222-EL-SLF

Dear Ms. Jenkins:

The Ohio Consumers' Counsel ("OCC") files the attached, revised testimony of Peter J. Lanzalotta, in accordance with the March 7, 2007, Entry in the above-captioned case. The revised testimony supplements Mr. Lanzalotta's testimony originally filed on January 19, 2007. The testimony has been updated with information gleaned from American Electric Power's ("AEP") Annual Reliability Reports filed in compliance with Ohio Adm. Code 4901:1-10-10(B)(3), 4901:1-10-10(C)(1), and 4901:1-10-10(C)(2), on March 23, 2007.

The revisions to Mr. Lanzalotta's testimony consist solely of additions and/or revisions to Table 1 on page 14 of the testimony, Table 2 on page 17 of the testimony, and Table 3 on page 28 of the testimony, as well as textual references to those tables. All the revisions are related directly to the Ohio Adm. Code filings noted above. The exhibits to Mr. Lanzalotta's testimony remain unchanged.

Yours very truly,

Richard C. Reese

Richard C. Reese
Assistant Consumers' Counsel

Cc: Parties of Record

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OCC EXHIBIT ____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability.	)))))	Case No. 06-222-EL-SLF

SUPPLEMENTAL TESTIMONY
OF
PETER J. LANZALOTTA

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

Dated: April 10, 2007

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I. INTRODUCTION

Q1. Please state your name, affiliation and business address.

A1. Peter J. Lanzalotta, Lanzalotta & Associates LLC, 67 Royal Pointe Drive, Hilton Head Island, South Carolina 29926.

Q2. Please describe your educational background.

A2. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

Q3. Please describe your professional experience.

A3. I am a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric utility system planning and operation, electric service reliability, cost of service, and utility rate design. I am a registered professional engineer in the states of Maryland and Connecticut. My prior professional experience is described in Exhibit PJL-1, which is attached hereto.

I have been involved with the planning operation, and analysis of electric utility systems and with utility regulatory matters, including reliability-related matters, certification of new facilities, cost of service, cost allocation, and rate design, as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities, regulatory agencies, developers, and electricity users over a period exceeding thirty years.

I have been involved in a number of projects focused on electric utility transmission and distribution system reliability. I have worked for many years on behalf of a number of both public and privately-owned clients on electric reliability-related matters. I am currently or have recently been engaged by various government offices and agencies in the states of Delaware, Maryland, New Jersey, and Pennsylvania to help address electric service reliability concerns.

Q4. Have you given expert testimony in any judicial or quasi-judicial proceedings?

A4. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and before regulatory commissions and other judicial and legislative bodies in 20 states, the District of Columbia, and the Provinces of Alberta and Ontario. My clients have included utilities, regulatory agencies, ratepayer advocates, independent producers, industrial consumers, the federal government, and various city and state government agencies. The proceedings in which I have testified are listed in Exhibit PJL-2.

Q5. What is the purpose of your testimony?

A5. My testimony, on behalf of the Ohio Consumers' Counsel ("OCC") presents the results of my evaluation of the reliability-related policies and practices that are applied to the distribution systems of the AEP Ohio electric distribution companies, Columbus Southern Power Company ("CSP") and Ohio Power Company ("OPC") (collectively, "AEP Ohio" or "the Company"). My testimony also addresses the electric service reliability performance of these distribution systems, as reflected in the electric service outage experience of the Company's distribution customers. This performance has become less reliable in recent years, as reflected in the electric service reliability index data collected by the Company. This declining performance calls into question the Company's policies and practices as they affect the reliability of the Company's electric distribution system. My evaluation compares the Company's policies, practices, and performance against typical industry practice, Ohio requirements, and against other standards of care. I also review the Company's proposed reliability programs regarding need, reasonableness, and whether these programs really represent something beyond what utilities would normally be undertaking.

Q6. On what information is your testimony based?

A6. In preparing my testimony I have reviewed the reports and other documents discussed or mentioned in this testimony (for example, AEP Ohio's Enhanced Distribution Service Reliability Plan ("the Plan"), the responses to multiple rounds of discovery, various FERC filings, and other documents related to electric service reliability). Also, I have reviewed documents not specifically mentioned in this testimony including the May 2003 Staff Report and Stipulation filed in Case No. 03-2570-EL-UNC, AEP Ohio's Final Report, and AEP Ohio's Self Complaint filed in the instant case before the Public Utilities Commission of Ohio ("PUCO" or "Commission").

Q7. Please summarize your findings.

A7. Based on my review, my findings are as follows:

1. System reliability performance (with major storms excluded), as reflected in AEP Ohio's reliability indices, has become less reliable, particularly in the area of outage frequency (SAIFI) and average outage minutes per year (SAIDI), prior to 2006.
2. System reliability index performance, with major storm data included, has become increasingly less reliability and more divergent from reliability indices with storm data excluded, especially in 2003 and 2004.
3. AEP Ohio's reliability index targets, especially those for outage frequency (SAIFI), keep getting less demanding, justified by the Company based on the fact that its reliability index performance in recent years has reflected lower reliability.
4. AEP Ohio installed an automated distribution system outage reporting system in the early 2000s to replace its system of manual data entry and handling of outage data. However, it apparently did so without benchmarking the effects of this system on its reliability indices by

performing parallel runs for the old and new systems using the same data for the same time period. The Company claims that this new technology has resulted in increases in its reliability indices (i.e. decreasing reliability), but, without parallel run verification, these increases in the reliability indices could just well be increasing, in whole or in part, because system reliability is getting worse.

5. Prior to 2006, AEP Ohio's reliability index targets have been moving in the direction of lower reliability, especially regarding outage frequency (SAIFI). The Company attributes this to the installation of its automated outage recording system, but without the parallel run benchmarking discussed in Item #4 above, these changes should be attributed in part or in their entirety to actual changes in system reliability.

6. Several of AEP Ohio's current reliability-related programs, including overhead circuit inspections and vegetation management, have been marked by large swings in the level of effort over the past four to five years, raising potential questions as to the consistency of the quality of these programs.

7. AEP Ohio's base vegetation management program is described in the Plan as performance-based, and I believe this has contributed to the deterioration in the Company's reliability index performance in 2003 and 2004, especially during major storms, as well as the need to spend in excess of $90 million over 2004 and 2005 for catch-up vegetation management.

8. AEP Ohio's incremental vegetation management program promises to inspect or trim all of its distribution circuits once during the next four years. However, the need to double the number of crews over five years, before reducing the number of these crews, raises questions to whether a more consistent level of vegetation management effort would be more sustainable and effective.

9. A program to deal with trees outside the right-of-way needs to be specified and made part of the vegetation management effort.

10. The incremental overhead line inspection program does not appear to be significantly different from the Company's existing program.

11. Parts of the Company's overhead mitigation program appear to represent incremental efforts that address significant reliability concerns regarding fuse cutouts and lightning arrestors that have been demonstrating increasing failure rates. The 34.5 kV program, however, while laudable, does not reflect an incremental effort.

12. The parts of the incremental reliability programs that deal with the replacement of aging equipment should not be considered as incremental to normal utility practice.

13. The installation of Supervisory Control and Data Acquisition ("SCADA") capability in those substations which do not currently have it should take precedence over more sophisticated distribution automation efforts.

14. The Plan appears deficient in several areas addressing implementation details, expected reliability benefits, formalized reporting, and regulatory review.

II. HISTORY OF AEP OHIO'S DISTRIBUTION SERVICE RELIABILITY

Q8. Please describe the events that have lead up to this evaluation of AEP Ohio's electric distribution reliability in Ohio.

A8. In early 2003, concerns about the reliability of the distribution service being provided in rural Ohio service territories by CSP and OPC caused the Commission staff to look more closely at the Company's policies, practices, and recordkeeping as they relate to inspecting, maintaining, and operating its distribution systems. The result was a May 1, 2003 report titled "Staff Concerns and Recommendations About Columbus Southern Power Company and Ohio Power Company's Provision of Electric Service" ("2003 Staff Report").

The 2003 Staff Report addressed concerns resulting from (1) rural distribution circuits that were among the Company's worst performing circuits from one year to the next, (2) reductions in distribution-related capital and maintenance expenditures, and (3) increases in service-related complaints from the Company's customers. The 2003 Staff Report also discussed a number of topics related to outage mitigation, including tree-trimming, wind-related outages, animal-related outages, system deterioration, equipment inspections and maintenance, and other topics related to the Company's electric service distribution system reliability.

The 2003 Staff Report expressed the opinion that the Company appeared to not be complying with certain Ohio Electric Service and Safety Standards ("ESSS Rules") and made a number of recommendations, which if implemented, could improve the Company's reliability performance.

Negotiations between the Commission staff and the Company during 2003 resulted in the December 31, 2003 Stipulation and Settlement Agreement ("Stipulation"), in which the Company agreed, among other things, to improve by 40% the 2002 reliability performance of the worst performing 25% (the 1st quartile) of its distribution circuits in Ohio over the two years following the Stipulation, without letting reliability performance of the rest of the distribution circuits decline.[1]

Q9. Please describe AEP Ohio's Final Report and Self Complaint filed on January 31, 2006.

A9. On January 31, 2006 AEP Ohio filed in Case No. 06-222-EL-SLF a "Year Two" final report which described the Companies' progress toward the improved reliability required in the Stipulation. The system average interruption duration index ("SAIDI") target for the first quartile of 279.2 minutes of annual outages per customer was met and exceeded at the end of 2005 with a SAIDI of 258.7 minutes. However, AEP Ohio reported that the 2002 baseline SAIDI was not

[1] *In the Matter of a Settlement Agreement between the Staff of the Public Utilities Commission of Ohio and Columbus Southern Power Company and Ohio Power Company*, Case No. 03-2570-EL-UNC ("03-2570"), Stipulation and Settlement Agreement dated December 31, 2003 at Item #1, p 2, and Item #4, p 3.

maintained for the remaining three quartiles of distribution circuits. AEP Ohio described unforeseen and uncontrollable events that the Companies believed contributed to their inability to meet the baseline SAIDI. According to AEP Ohio these issues included an increase in the failure rate of distribution line equipment, an increase in the number of distribution station outages, and uncontrollable events such as vehicle accidents and the mutual assistance needs of other electric utilities.

AEP Ohio also filed a Self Complaint on January 31, 2006 that was intended to focus the Commission on the future direction of service reliability. AEP Ohio pointed out that some of the factors impacting SAIDI were controllable by the Companies at some incremental cost. AEP Ohio requested that the Commission implement a proceeding in which an enhanced reliability program, proposed by AEP Ohio, would be reviewed and authorized by the Commission.

Q10. Please describe the Staff Investigative Report of April 17, 2006.

A10. On April 17, 2006, Commission staff filed a report setting forth its findings and recommendations for improving AEP Ohio's distribution service reliability ("2006 Staff Report"). In its report, Commission staff analyzed the drivers of the Company's reliability performance. Commission staff felt that the Company's distribution system is in need of a resource intensive plan for replacement of aging underground and overhead infrastructure. Commission staff found that over the past five years, AEP Ohio's system-wide reliability performance has been getting worse on all measures, even after their efforts during the stipulation period. Commission staff recommended that the Commission separate the consideration of the issues into two separate dockets. The 03-2570-EL-UNC docket should focus solely on the consequences of the Companies' failure to comply with the Commission Order approving the Stipulation. The 06-222-EL-SLF docket could address the reliability concerns of the future. Commission staff recommended that the comprehensive plans to address future reliability should address the replacement of aging system infrastructure, vegetation management, mitigation of lightning-caused faults, improved fault cause identification, reduction of errors, and improved outage restoration times.

Q11. Please describe AEP Ohio's Enhanced Distribution Service Reliability Plan.

A11. The Company filed its Enhanced Distribution Service Reliability Plan on October 6, 2006 in response to the Commission's July 26th order for the Company to submit a proposed reliability plan. The Plan reviews selected parts of what the Company calls base distribution reliability programs, and includes the distribution pole inspection program, overhead circuit inspection programs, pad-mounted transformer programs, line recloser programs, line capacitor programs, the network system maintenance program, the distribution vegetation management program, and the distribution substation reliability programs. These programs are already in effect.

The Plan also describes what it calls its incremental distribution reliability plan. This incremental plan is touted as the means by which the Company can reach the next level of reliability, by focusing on initiatives to address the Company's aging infrastructure and customers' demand for increased quality of service. The incremental distribution reliability plan expands on the Company's base distribution reliability programs, adds incremental reliability programs, and provides for increased funding by ratepayers for the Company's reliability-related programs. The incremental distribution reliability programs proposed by the Company address vegetation management, overhead line inspections, overhead mitigation programs (including an accelerated equipment and hardware replacement program, an incremental recloser protection program, an incremental 34.5 kV protection program, and an incremental fault indicator program), underground mitigation programs, distribution substation programs, and programs implementing developing technology.

I will discuss the Plan proposal, the reasons the Company gives for proceeding with this proposal, and the base and incremental programs that make up the Plan later in my testimony.

III. DISTRIBUTION RELIABILITY STANDARDS AND MEASUREMENTS

A. Commonly Used Measurements

Q12. How is electric distribution service reliability typically measured?

A12. Although there are a number of different ways to measure electric distribution service reliability performance, the reliability indices SAIFI, CAIDI, and SAIDI are among the most widely used.

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

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

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

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

Q13. Are there any other reliability index data reported by the Company?

A13. Yes. The Company also reports Average Service Availability Index ("ASAI"). The ASAI is calculated by dividing (1) the customer-hours of service supplied despite the outages that occurred by (2) the total customer hours of service that would have been supplied if there were no outages. I feel that use of the ASAI tends to obscure meaningful evaluations of electric service reliability performance, and is also duplicative of data found in the other reliability indices.

For these reasons, my evaluation of AEP Ohio's reliability performance primarily uses other reliability indices in preference to ASAI.

B. AEP Ohio's Historical Performance

Q14. What has the Company's reliability performance been like in recent years?

A14. Table 1 below depicts reliability index data by year for the CSP and OPC distribution systems as reported in response to ESSS Rule 10.

Table 1

AEP Ohio Reliability Indices (major storms excluded)							
	CSP				Ohio Power		
	SAIFI	CAIDI	SAIDI		SAIFI	CAIDI	SAIDI
1998	1.200	120.0	138.0		1.000	198.0	198.0
1999	1.399	121.8	170.4		0.914	142.2	130.0
2000	1.572	141.6	222.6		0.918	160.2	147.1
2001	1.474	120.4	177.5		1.240	140.1	173.7
2002	1.620	122.8	198.9		1.345	167.4	225.1
2003	1.905	123.6	235.5		1.415	151.5	214.3
2004	1.861	116.8	217.4		1.451	144.4	209.5
2005	1.894	130.7	247.6		1.511	146.7	221.7
2006 [2]	1.47	113.83	166.79		1.410	137.63	194.7
2006 [3]	1.340	116.9	156.0		1.190	143.9	172.0
Avg. 1998-2001	1.411	126.0	177.1		1.018	160.1	162.2
Avg. 2002-2006[4]	1.750	121.5	213.24		1.426	149.53	213.1
Percent Change	24.00	-3.50	20.39		40.12	-6.62	31.38

Source: Data for 1998-2006 from the Company's response to OCC Interrogatory 10 and ESSS Rule 10 reports.

[2] Rule #10, 2006 Distribution System Reliability Report.
[3] Projected reliability for 2006 based on the Company's original Application, updated by the responses to OCC Interrogatory 10 and Staff data Requests 1.3, and 4.1. CSP and OPC customers experienced more outage minutes than projected by AEP for 2006.
[4] Based upon actual 2006 experience.

The SAIFI data in Table 1 reflects the number of electric service outages per year experienced by the average customer. The CAIDI data reflects the length of the average customer outage, in minutes. The SAIDI data reflects the total number of minutes of electric service outages experienced by the average customer per year. As can be seen above, reliability performance, prior to 2006, had declined in several important respects starting around 2001 (as noted earlier, higher index values mean lower electric service reliability). This decline in performance is reflected by an increase in SAIFI index values (more customer outages per year) and in SAIDI index values (more minutes of outages per customer per year) for both CSP and OPC. As can also be seen from Table 1 in 2006 the Company's electric service reliability performance, with major storms excluded, improved, in some cases considerably, compared to the four previous years.

The average CSP customer saw an average of 1.75 service interruptions per year from 2002 to 2006, compared to an average of 1.411 service interruptions per year for the four years before that (an increase of 24.0%). The average OPC customer saw an increase in average annual service interruptions to 1.426 interruptions per year from 1.018 interruptions per year over the same period (an increase of 40.12%).

The average CSP customer saw an average of about 213.24 minutes of service interruptions per year from 2002 to 2006, compared to an average of about 177.1 minutes of service interruptions per year for the four years before that (an increase of 20.39%). The average OP customer saw an increase in the average annual minutes of service interruptions to about 213.1 minutes per year from 162.2 minutes per year over the same period (an increase of 31.38%). The average duration of each Company's electric service interruption (CAIDI) decreased slightly over the same time periods.

Of course, the reliability index data in Table 1 does not really reflect the electric service reliability being experienced by AEP Ohio's customers, since it excludes all electric service outages that occur during major storms. Because storm activity is typically not constant from one year to the next, removing storm impacts from reliability data de-emphasizes the more variable reliability effects of storms. However, this approach loses touch with what electric service customers are actually experiencing, and, at best, can actually encourage maintenance and operating practices that tend to ignore the reliability impacts suffered during storms, and, at worst, can actually increase the reliability impacts suffered during storms.

Table 2 below reflects the same reliability indices as in Table 1, only these indices include electric service interruptions experienced by customers during major storms.

Table 2

AEP Ohio Reliability Indices (major storms included)						
	CSP			Ohio Power		
	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI	SAIDI
1998	1.264	121.2	153.2	1.066	228.0	243.1
1999	1.439	118.5	170.6	0.973	134.1	130.5
2000	1.678	132.9	223.1	1.051	141.1	148.3
2001	1.485	119.5	177.5	1.380	126.5	174.6
2002	1.779	148.7	264.5	1.643	231.3	380.1
2003	2.506	347.9	871.8	2.068	431.2	891.6
2004	2.759	652.7	1,801.0	2.126	466.0	990.7
2005	2.130	141.1	300.4	1.880	369.2	694.4
2006	1.69	141.71	239.01	1.85	310.36	574.64
Avg. 1998 – 2001	1.467	123.1	181.1	1.118	157.4	174.1
Avg. 2002 – 2006	2.17	286.41	695.34	1.91	361.62	706.29
Increase	48.16%	132.76%	283.98%	71.22%	129.70%	305.63%

Source: ESSS Rule 10 Reports.

As shown in the last three lines of Table 2, looking at the average electric service outage frequency (SAIFI) with storm outages included the average CSP customer saw an average of 2.17 service interruptions per year from 2002 to 2006, compared to an average of 1.467 service interruptions per year for the four years before that (an increase of 48%). The average OPC customer saw an increase in average annual service interruptions to 1.91 interruptions per year from 1.118 interruptions per year over the same period (an increase of 71%).

Similarly, looking at the average annual minutes of service interruptions per customer (SAIDI) with storm outages included the average CSP customer saw an average of about 695 minutes of service interruptions per year from 2002 to 2006, compared to an average of about 181 minutes of service interruptions per year for the four years before that (an increase of 284%). The average OPC customer saw an increase in the average annual minutes of service interruptions to about 706 minutes per year from 174 minutes per year over the same period (an increase of 306%). The average duration of each Company's electric service interruption (CAIDI) also increased substantially over the same time periods when outages occurring during major storms are included, although by less than for SAIDI.

It is also useful to note, comparing data from Table 2 to Table 1, that there is relatively little difference between the average reliability indices for the period 1998 to 2001 regardless of whether storm-related outages are included or not. By way of contrast, there are large percent increases in the number of interruptions experienced and their duration during 2002-2006 when storm related outages are included in the reliability indices. While the level of storm activity may have varied before and after January 1, 2002, based on the increases in outage duration reflected in Table 2, the ability of the Company to deal effectively with storms seems to have weakened significantly over the same period.

Q15. What have been the leading causes of outages on the Company's system?

A15. The Company's top five outage causes in recent years are equipment failure, distribution substation causes, trees in the right-of-way, trees outside the right-of-way, and weather or lightning.[5]

IV. ELECTRIC SERVICE AND SAFETY STANDARDS AND RULES

Q16. What are Ohio's requirements regarding providing reliable electric distribution service?

A16. The requirements regarding providing reliable service are found in Ohio Administrative Code Chapter 4901:1-10, titled Electric Service and Safety Standards ("ESSS"). These rules, as a whole, "...are intended to promote safe and reliable service to consumers and the public, and to provide minimum standards for uniform and reasonable practices."[6] Thus, the ESSS Rules address electric service issues that involve reliability and/or safety.

Some of the sub-parts of the ESSS Rules specifically impact electric service reliability. For example, 4901:1-10-02 Purpose and scope ("ESSS Rule 02"), states that the Rules apply to investor-owned electric distribution utilities ("EDUs") and transmission owners with the intent described above. This Rule goes on to give the Commission the power to waive or to go beyond the requirements of the Rules, and states that the Rules do not relieve the EDUs or the

[5] The Plan at 20-21.

[6] 4901:1-10-02(A)(2) Purpose and scope.

transmission owners from the responsibility to provide adequate service and facilities, as prescribed by the Commission. Thus, the Commission can specifically address the level of service reliability that is being provided to rural portions of the system, if such level of reliability can be shown to be inadequate.

Q17. Are there any other standards by which to judge electric service reliability?

A17. Yes. I believe that electric utilities have a responsibility to avoid declining electric service reliability performance even in the absence of regulatory requirements, rules or statutes. Even if all requirements deriving from the ESSS Rules are met, ongoing declines in electric service reliability that are within the Company's control should be considered a breach of this general standard, unless such changes are approved by the Commission.

A. Data Retention Period

Q18. Please discuss the data retention period that is provided for in the ESSS Rules.

A18. 4901:1-10-03 Retention of records ("ESSS Rule 03") requires that, unless otherwise specified, records sufficient to demonstrate compliance with the Rules shall be maintained for three years. However, in areas regarding distribution system planning, maintenance and operation, retention of data for only three years is really too short a period to be sufficient for reliability purposes. There are a number of reasons for this. One reason that three years is too short is because changes in the facilities installed on a distribution circuit, and/or changes in maintenance being applied to a distribution circuit typically take some time to implement and more time before they are reflected in the reliability performance of the circuit to which they apply. For example, in order to determine if a distribution circuit is having reliability performance problems, typically at least one year of reliability performance data is needed. (Presumably, the reliability of a distribution circuit could be so poor as to be identifiable from less than one year of operation, but, for system-wide application, at least a year of performance data is preferable.)

Next, once a distribution circuit is determined to be a candidate for reliability improvement, the repair and/or replacement of poles, crossarms, and/or conductors, the application of directed tree trimming, and the implementation of other improvements will take some time to be completed. These types of actions could take part of a year, or longer, to be implemented. Finally, once implemented, it will take some time for the reliability performance of the circuit in question to reflect these improvements, typically at least one year of operation after the completion of improvements.

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

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

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

Q19. What minimum data retention period do you recommend?

A19. A minimum data retention period of five years is needed in order to have a reasonable chance of correlating the level of distribution system electric service reliability that results from specific planning, maintenance, or operating policies.

B. Distribution System Reliability

Q20. What other ESSS rules address electric system reliability?

A20. 4901:1-10-10 Distribution System Reliability ("ESSS Rule 10") addresses what electric service reliability index data should be used in measuring electric service reliability performance of EDU distribution systems. The reliability indices discussed previously reflect Rule 10. Rule 10 also addresses what electric service reliability performance data should be excluded from the calculation of reliability indices, and how targets for reliability index performance are set.

Q21. Are there any other aspects of ESSS Rule 10 that you wish to address regarding electric service reliability performance?

A21. Yes. Rule 10(B)(3) provides that outage data for service interruptions that occur during major storms[7], and outage data for service interruptions caused by outages of transmission facilities should not be included in the calculation of reliability performance indices or used in the determination of index performance targets.

[7] Major Storms are storms in which the restoration of electric service takes more than 24 hours and in which assistance from another district is required. See AEP Ohio response to OCC Interrogatory 21. (Exhibit PJL-3).

While there are justifications for using outage data that has been stripped of customer outages that occur during especially bad weather[8] (or for using outages data stripped of customer outages resulting from transmission system events[9]), there is a good reason for also calculating a set of reliability indices with customer outages that include major storms.

Including major storm service interruptions in the calculation of one set of reliability indices reflects what the customer is actually seeing in the way of distribution service reliability. If a purpose of looking at reliability index calculations is to promote the provision of reliable electric service to customers, then reliability index calculations that include major storm-related outages that customers are experiencing should be available. The removal of major storm-related customer outages from all reliability indices can obscure changes in the distribution system's ability to provide reliable service during bad weather. If major storm-related customer outages carry lesser weight in evaluating distribution system reliability performance than outages that are not storm-related, then EDUs will have less incentive to design and/or maintain their distribution systems so as to maintain or to increase their ability to withstand storm-related events. As system components age, they become more susceptible to failure

[8] Because the effects of bad weather on distribution system reliability typically vary from year to year, removing the customer outages resulting from bad weather from the calculation of the reliability indices attempts to make year-to-year reliability indices more reflective of the reliability inherent in the system and less reflective of variations in weather.
[9] Removal of customer outages resulting from transmission system interruptions from the calculation of reliability indices results in reliability indices that focus on distribution system performance. Since most customer outages typically result from distribution system events, this focus is useful.

during high stress events, such as during storms. Recent AEP Ohio policies to withhold tree-trimming from distribution circuits until they show negative reliability impacts due to tree contact can be expected to increase storm-related customer outages due to lack of tree-trimming, as the effects of wind and ice on reliability are increased by the lack of tree-trimming.

For these reasons, it is reasonable and appropriate for the Commission to require AEP Ohio to calculate a set of reliability index data (SAIFI, CAIDI, SAIDI) for each of its companies reflecting all distribution-related outages without exclusions.

C. *Customer Interruption Data*

Q22. Has AEP Ohio made changes in its handling of customer interruption data that resulted in impacts on the reliability indexes it calculates?

A22. Yes. AEP Ohio claims that improvements it has made to its handling of customer interruption data have increased the accuracy of this data, and, as a result, the reliability indexes it calculates from this interruption data have been increased compared to what they would have been. However, as my testimony shows, increases in AEP Ohio's reliability index data indicate less reliable service.

In 1995, the Company started installing an automated distribution service outage reporting system in which electric service outages, the number of customers affected, the length of the outage, and other data are recorded electronically.[10] The initial installation process lasted until 2001, with upgrades continuing until August, 2003.[11]

Utilities which install automated distribution service outage reporting systems frequently claim to experience increases in the numbers of outages recorded, increases in the number of customers experiencing, and/or increases in the customer-minutes of service interruption.[12] However, these claims are based on comparing outage data recorded by the old system for the period of time prior to the implementation of the automated system with the outage data recorded by the automated system after it is implemented. The problem with this type of comparison is that any change in the reported system reliability performance between these two separate time periods is typically attributed to the implementation of the automated system, and not to the significant possibility that the actual reliability performance may have changed from one time period to the next.

Without conducting parallel run studies which look at the data produced by the automated system over a certain period of time and compare it with data produced by the manual data collection system operating over the same period of time, it is

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[10] Prior to this, outage data was manually recorded or manually entered into a recording system.
[11] See AEP Ohio response to OCC Interrogatory 253 (Exhibit PJL-4).
[12] See AEP Ohio response to OCC Request for Production 85 (Exhibit PJL-5).

not possible to say for certain just what impact the implementation of an automated outage reporting system has had for a particular utility.

AEP Ohio implemented its automated system without any apparent attempt to measure the impact of the change from a manual system to an automated system on a common set of outage data by conducting parallel runs of both the new automated system and the manual system that preceded it.[13] Therefore, it is impossible to know from the information available whether the implementation of AEP Ohio's automated distribution service outage recording system has resulted in increased reliability indices, or whether distribution system reliability has actually gotten worse. All we know for sure is that, from 2002 through 2005, AEP Ohio's outage frequency, as reflected in its SAIFI index, increased significantly (See Table 1 above).

Considering that one primary use of reliability indices is to allow comparison of current reliability performance with historical reliability performance, AEP Ohio's actions undermine one of the basic purposes of the ESSS Rules.

[13] Ibid.

V. TARGETS FOR RELIABILITY INDICES

Q23. How are the reliability indices calculated by AEP Ohio used to evaluate electric service reliability on its system?

A23. They are used in several ways. One of these, as addressed in ESSS Rule 10, is to compare the EDU's system reliability indices for a period of time, typically one year, against performance targets. Rule 10 specifies that these performance targets should reflect historical performance, along with other factors. Table 3 below depicts reliability target data for the Company.

Table 3

	CSP Targets			Ohio Power Targets		
	SAIFI	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**	**SAIDI**
1998	1.000	144.0	138.0	1.000	168.0	150.0
1999	1.000	144.0	138.0	1.000	168.0	150.0
2000	1.291	161.2	163.5	1.019	215.6	218.6
2001	1.291	161.2	163.5	1.019	215.6	218.6
2002	1.291	161.2	163.5	1.019	215.6	218.6
2003	1.291	161.2	163.5	1.019	215.6	218.6
2004	1.291	161.2	163.5	1.019	215.6	218.6
2005	1.291	161.2	163.5	1.019	215.6	218.6
2006	1.29	161.2	163.5	1.02	215.6	218.6
Proposed[14]	1.859	143.0	265.8	1.397	169.0	236.0

SOURCE: ESSS Rule 10 Reports

[14] Proposed by the Company in 2002, per its ESSS Rule 10 Report (Exhibit PJL-6).

AEP Ohio set performance targets in 1998, to be effective in 1999 that reflected average interruption data for the five year period 1993 to 1997. Storm outage data was included in these targets.[15]

AEP set new performance targets in 1999. These targets exclude storm outage data.[16] Normally, excluding storm outage data from the calculation of these reliability indices would result in a reduction of the indices reflecting the frequency of interruptions (SAIFI) as well as the indices depicting the average annual minutes of interruption per customer. However, in this instance, eliminating storm outage data was accompanied by an increase in CSP's target outage frequency (SAIFI), from 1.0 outages per year to 1.291 outages per year, an increase in CSP's target average outage duration (CAIDI) from 144 minutes per outage to 161 minutes, and an increase in CSP's target average annual minutes of interruption per customer (SAIDI) from 138 minutes per year to about 163 minutes per year. Similarly, eliminating storm data was accompanied by increases in OPC's target outage frequency from 1.000 outages per year to 1.019 outages per year, an increase in OPC's target average outage duration from 168 minutes per outage to 216 minutes, and an increase in OPC's target average annual minutes of interruption per customer from 150 minutes per year to 219 minutes per year.

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[15] Distribution System Performance Data reflecting 1997 performance, ESSS Rule 10 Report (Exhibit PJL-7).
[16] Distribution System Performance Data for 1999, ESSS Rule 10 Report (Exhibit PJL-8).

These new targets reflected an apparent substantial decrease in target electric service reliability. As stated above, the Company has taken the position that its automated system for the collection of outage data is resulting in increased reliability indices due to the improved accuracy of this system. However, there is no data from any parallel runs studies between the automated system and the manual system that preceded it to support this contention.

AEP Ohio requested another change in their system performance targets on December 30, 2002, but subsequently agreed, as part of the Stipulation in 03-2570, to withdraw this request, apparently with the understanding that new targets could be submitted to the Commission staff when reliability mitigation impacts have been determined. These requested changes, depicted on the last line of Table 3, reflect substantial increases in outage frequency, reflected in the SAIFI index, and varying increases in average annual minutes of outage per customer, reflected in the SAIDI index, while reducing the target for average outage duration (CAIDI). Because of the Company's lack of parallel analyses between its automated data collection system and the manual system that preceded it, there is no way to know if the proposed increases in allowable SAIFI and SAIDI reflect the effects of the automated outage reporting system or if they reflect declining system reliability. Based on 2006 reliability performance, the Company appears to have met most of the targets with the exception of the CSP SAIFI and SAIDI and the OPC SAIFI.

VI. THE PLAN: BASE RELIABILITY PROGRAMS

Q24. How do the Plan proposals regarding distribution system maintenance fit in with the ESSS rules?

A24. The Plan proposals provide primarily for changes in system maintenance practices that are traditionally addressed by Rule 27.

Q25. Please describe the current distribution-related practices that are addressed in the Plan.

A25. The Plan first reviews selected parts of what the Company calls its base distribution reliability programs. These programs are currently in effect and include the distribution pole inspection program, overhead circuit inspection programs, pad-mounted transformer programs, line recloser programs, line capacitor programs, the distribution vegetation management program, the distribution substation reliability programs, and others.

A. Pole Inspection Program

Q26. Please address the distribution pole inspection program.

A26. AEP Ohio conducts pole ground-line inspections and treatment on a ten-year cycle for poles older than 20 years old. In recent years, the Company has increased the time to the initial inspection from 16 years to the present 20 years[17], despite the increasingly prominent role that equipment failures have played in

[17] See AEP Ohio response to OCC Request for Production of Documents 74 (Exhibit PJL-9). AEP Ohio response to OCC Request for Production of Documents 74-2002.pdf (Exhibit PJL-10), AEP Ohio response to OCC Request for Production of Documents 74-2004.doc (Exhibit PJL-11), and the Plan at 7.

interrupting electric service to customers. A ten-year cycle for electric distribution wood pole inspections is common practice in the electric utility industry, in my experience.

B. Overhead Circuit Inspection Program

Q27. Please address the overhead circuit inspection program.

A27. AEP Ohio conducts overhead distribution circuit inspections on a five-year cycle. This cycle is mandated by ESSS Rule 27. A five year cycle for such inspections is common, in my experience.

I note that for the past five years, the number of miles of circuit inspections has varied from less than 6,000 miles in 2002 to more than 13,000 miles in 2004, and back down to something less than 8,000 miles in 2006.[18] Wide swings in inspection workload from one year to the next typically raise concerns about the consistency of the quality of these inspections. It is questionable whether the existing workforce is adequate to perform more than double the amount of a particular type of work, without using less qualified or less experienced personnel, or without neglecting other tasks. If additional personnel are required, they must have the necessary qualifications and experience. When work levels yo-yo up and down, retention of these qualified and experienced people becomes a concern. In addition, when the Company is inspecting more than 13,000 miles of circuit in one year, it becomes comparatively more difficult to address the

[18] Plan Chart 2 (at 9).

problems turned up by these inspections in a timely manner. These are all concerns that do not arise when inspections and maintenance are performed in a consistent manner.

In addition, a more levelized inspection program also helps avoid customer outage minutes that can occur if circuits that should have been inspected and repaired at five years are part of a catch-up in some subsequent year. Also, the amount of catch up, if any, that occurred between 2002 and 2006 may have been more obvious had the Company provided circuit inspection data for a longer historical period.

The Company also includes overhead distribution circuit inspections as an incremental reliability program. This is addressed in the section of my testimony that discusses the Company's proposed incremental reliability programs.

C. Vegetation Management Program

Q28. Please address the distribution vegetation management program.

A28. Vegetation management is one of the more problematic areas of the Company's distribution maintenance programs. In the early 2000s, the Company's filed distribution system vegetation management policy reflected total circuit trimming on a four-to-six year cycle, with additional off-cycle clearing to deal with problem areas prior to the next total trim. The 2003 Staff Report found[19] that the Company

[19] 2003 Staff Report at 8.

was using hot-spot trimming (isolated trimming in response to tree-caused outages) and postponing tree trimming on a circuit until reliability performance on that circuit deteriorates to the worst 15% of circuits due to tree-related service interruptions, and that these policies were being substituted for the four-to-six year cycle for the complete trimming of each circuit.[20] Staff believed that use of these policies without having been reported under ESSS Rule 27 were unauthorized and in violation of ESSS Rule 27 (E)(2)(c). Based on the information available, I can only affirm this Staff conclusion.

In the Plan, the current vegetation management program is described as "performance-based" which prioritizes work on distribution facilities based on a number of variables, including the elapsed time since the last vegetation management activities were performed on the facility, inspection results, tree-related reliability performance, and other factors.[21] Despite vigorous attempts via discovery, I have little basis on which to evaluate how this prioritization process works or what weight is given to these various factors.

I note that the annual miles of vegetation management activity over the past three years, as reflected in Chart 8 of the Plan, varies from something over 7,000 miles in 2004 to around 3,500 miles in 2006. Wide swings in vegetation management

[20] When OCC requested copies of the discovery material that had been provided to Staff and that was referenced by Staff in reaching these conclusions, the Company was unable to provide them, (Exhibit PJL-12).
[21] Plan at 15.

workload from one year to the next typically raise concerns about the consistency of the quality of these activities for the same reasons raised in the previous discussion concerning overhead inspections.

There have also been wide swings in the Company's annual spending on vegetation management, shown in Table 4, below.[22]

Table 4

AEP-Ohio	2002	2003	2004	2005
	$20,226,371	$24,999,544	$40,278,595	$51,289,697

The Company's spending on vegetation management more than doubled in 2004 and 2005, compared to the two previous years.

Q29. Please address the relationship between vegetation management and momentary outages.

A29. Vegetation management is usually a significant factor as a cause of momentary service interruptions, which last five minutes or less. These interruptions can cause loss of data in computers and can result in the need to reset many types of modern appliances and electronics. Commission staff mentions this in the 2003 Staff Report[23] and explains how circuit breakers and reclosers on overhead distribution circuits are designed to operate, i.e., open, when a fault is detected, and then to close after a few seconds, to see if the fault has cleared. If the fault is

[22] Exhibit PJL-13.
[23] 2003 Staff Report at 10.

gone, the breaker or recloser stays closed, and customers downstream from that device have experienced a momentary outage. If the fault is still there, the device opens again and typically locks out in the open position until the circuit can be checked for faults.[24] Falling tree branches and tree limbs swaying in the breeze can cause faults that disappear after a second or two. When a customer, or a distribution circuit, experiences high numbers of momentary outages, trees are one of the most likely causes. Of course, since the Company does not report numbers of momentary interruptions, a customer would most likely have to complain before the Company became aware of the problem.

Q30. Is the use of "performance-based" vegetation management typical among electric utilities?

A30. The use of "performance-based" direction of at least some vegetation management activities is on the increase among electric utilities. It may take the form of something as simple as annual listings of a utility's worst performing distribution circuits, with these circuits targeted for remedial action that frequently includes tree trimming. However, many utilities still have an overall trimming cycle based on a comprehensive trimming, or other application of vegetation management techniques, every so many years. There is considerable variability in the lengths of these cycles. My experience in other states indicates that some utilities are currently switching to a three-year vegetation management

[24] Some circuit breakers or reclosers may be set to operate several times in this fashion before locking out.

cycle for distribution facilities, while others use a four-year, or longer, cycle. Some use mid-cycle hot-spot trimming.

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

Vegetation management is also targeted in the incremental distribution reliability plan, and is further discussed in that section of my testimony.

D. Distribution Reliability Programs

Q31. Please address the distribution substation reliability programs.

A31. The Company's current distribution substation reliability programs include monthly inspections and for the maintenance of substation equipment, including circuit breakers and transformers. The Company's filed practices in these areas appear generally consistent with reliable operating practice, with one noteworthy exception: replacement of old and obsolete equipment, both inside the substation and out on the distribution circuits, is usually a part of normal utility practice and is not an incremental activity. Electric system equipment is constantly aging and utilities have always been faced with the need to replace such equipment as it reaches the end of its useful life. This not a new activity or a new requirement of maintaining an electric distribution system.

VII. THE PLAN: INCREMENTAL RELIABILITY PROGRAMS

Q32. Please describe and address the incremental distribution reliability plan described in the Plan.

A32. The Plan describes what it calls its incremental distribution reliability plan, which is touted as the means by which the Company can reach the next level of reliability, by focusing on initiatives to address the Company's aging infrastructure and customers' demand for increased quality of service. The incremental distribution reliability plan expands on the Company's base distribution reliability programs, adds incremental reliability programs, and provides for increased funding by ratepayers for the Company's reliability-related programs. The incremental distribution reliability programs proposed by the Company are addressed below.

A. Vegetation Management

Q33. Please address vegetation management as addressed in the incremental distribution reliability plan.

A33. Regarding vegetation management, AEP Ohio plans to balance its current performance-based approach to reflect a greater consideration of cycle-based factors. The Company commits to inspecting or maintaining all of its distribution rights-of-way at least once during a four year period. During the initial four year period of the incremental plan, the Company would totally clear out vegetation and would employ the use of improved technology to collect, store, predict and analyze specific vegetation data. During this period, the Company would inventory tree species' growth rates to create detailed work plans for each circuit to annually predict and schedule maintenance cycles as needed. Other factors that would be considered are the location of vegetation in proximity to the conductors, accessibility, density, and vegetation coverage. AEP Ohio proposes what it calls significant increases in its vegetation management funding, which over a 12-month period would double the current number of tree crews available to perform end-to-end clearing on all of its distribution lines. Once the distribution system has been totally cleared and inventoried, the Company expects the number of tree crews to decrease.[25]

The need to employ a four-year crash program in vegetation management is to some degree an admission that the Company's Commission-unapproved performance-based program of vegetation management has allowed the vegetation situation on the distribution system to get out of control in recent years. The deteriorating reliability index performance of the distribution system in stormy weather supports this.

In addition, if the Company needs to double the current vegetation management capability in order to fully inspect and/or trim each of its distribution feeders once

[25] Plan at 22-23.

over the next four years, this certainly suggests that current capabilities have been allowed to atrophy to a level far short of what is needed to maintain system reliability.

There are several apparent inconsistencies regarding the Company's vegetation management proposal. The incremental vegetation management plan is described as a significant increase in spending, yet it's annual costs (capital and O&M combined) range from about $23 million per year to about $30 million per year for five years.[26] However, in 2004 and 2005 the Company spent a combined $90 million on vegetation management (see Table 4 above). The results were that the contribution to SAIDI from trees has decreased by half since 2002 for trees in the right-of-way and has decreased by about one-third since 2004 for trees outside the right-of-way.[27] The need to double the number of crews so soon after the heavy spending on vegetation management in 2004 and 2005 is an indication of the extent to which the Company had allowed the situation to deteriorate.

I note also that the Company seems uncertain as to what kind of clearances above, below and around electric distribution conductors it plans to achieve with its vegetation management program. When asked this question (OCC-IR258), the

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[26] Plan Chart 10 at 23.
[27] Plan Chart 9.

Company said only that its horizontal and vertical tree trimming clearances were under review.[28]

1. Trees Outside The Right-Of-Way

Q34. Please discuss how the Company proposes to address the reliability problems caused by trees located outside the distribution right-of-way.

A34. The Company's vegetation management proposal does not appear to address the interruption caused by trees located outside the distribution right-of-way. Such trees represent a special problem, as a utility's right to trim trees located outside the right-of-way is usually limited and frequently requires permission from property owners.[29] Additionally, outages caused by such trees are listed by the Company as one of the five leading causes of customer interruptions, as noted earlier in my testimony.

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

[28] AEP Ohio response to OCC Interrogatory 258 (Exhibit PJL-14).
[29] The trimming of limbs that extend into the right-of-way are typically not restricted in this way.

required and is actively pursued. The Company's vegetation management plan should include provisions to address these problem trees.

B. Overhead Line Inspections

Q35. Please address overhead line inspections as included in the incremental distribution reliability plan.

A35. The Company proposes to maintain overhead line inspections on the current five-year cycle, but to increase the comprehensiveness and attention to detail in the inspections. The Company suggests that current overhead distribution line inspections are more of a drive-by nature.[30] Under the incremental plan, circuits would be walked, or perhaps inspected more closely by climbing structures or by using a bucket truck to inspect hardware and equipment. Infrared scanning or radio frequency detection devices would also be used.

It is not at all clear that there are significant differences between what the Company proposes and what the Company is supposed to be doing currently, regarding the five year overhead circuit inspections. It is not clear that personnel currently performing these inspections perform them while driving down the road. (In his deposition, AEP Ohio employee Karlen Cooper stated that these inspections have always been performed by walking the circuit.[31]) If performed from a parked vehicle, it is not clear that such inspections are inferior to

[30] Plan at 24.
[31] Deposition of Karlen Cooper in Case No. 06-222-EL-SLF, January 9, 2007, p. 17, lines 15-22 (Exhibit PJL-15).

performing an inspection while standing up, as long as the circuit is in close proximity. For circuits that do not follow roads, there is no way to perform such inspections at present, short of walking the circuit, or, perhaps flying it. And under current practice, if an inspection shows problems on an overhead circuit, repairs are called for under the ESSS Rule 27 procedures AEP Ohio has filed.

The Company lists categories of repair and replacement work that might result from these inspections. None of these categories or repair or replacement reflect anything that utilities don't already do in response to inspections of overhead distribution facilities. The Company plans to replace hardware and equipment that are either prone to failure or that have the potential to fail within the next five years. This suggests that, under the current program, hardware and equipment that are known to be failure prone or that have the potential to fail within the next five years are knowingly left in service, presumably until they fail.

C. Overhead Mitigation Programs

Q36. Please address the overhead mitigation programs that are included as part of the incremental reliability plan.

A36. The Company is proposing overhead mitigation programs, including an accelerated equipment and hardware replacement program, an incremental recloser protection program, an incremental 34.5 kV protection program, and an incremental fault indicator program.

The accelerated equipment and hardware replacement program addresses reliability issues involving fused cutouts and lightning arrestor failures. The Company reports experiencing premature failures on both these equipment types. As the Plan indicates, premature failures of cutouts and arrestors is an industry-wide problem.[32] Addressing both of these equipment problems will help address two of the more significant drivers of customer outages on the Company's distribution system, i.e., line equipment failures and lightning.

The incremental recloser program deals with the replacement of 3-phase reclosers with multiple single-phase reclosers. Three phase reclosers interrupt all three phases of a distribution circuit, even if only one of the phases is experiencing an electrical fault. Using single phase reclosers limits interruptions to the phase or phases actually experiencing a fault, thereby reducing customer service interruptions.

The incremental 34.5 kV protection program includes installing additional sectionalizing devices on these circuits, installing lightning arrestors on these circuits, and/or adding reactors to these circuits. Additional sectionalizing devices, such as reclosers, will tend to limit the impact of faults so that only a portion of a circuit will be impacted by faults in certain locations of the circuit. Lightning arrestors work to limit the effects of lightning strikes on the circuit. Reactors work to limit fault current on these circuits so as to lessen the stress on devices (i.e., breakers, reclosers, fuses) that are responsible for interrupting such

[32] Plan at 29.

fault currents when they occur, and to improve coordination among various protection devices installed on each such circuit. These actions reflect normal engineering practices for the management of distribution circuits. AEP Ohio has not demonstrated how its incremental program goes beyond what it should be doing on a normal basis.

The incremental fault indicator program provides a means for more quickly locating where temporary or permanent faults are occurring. This capability is especially useful on distribution circuits that include a mix of overhead and underground facilities, as the locations of underground faults can be difficult to locate. However, such devices can speed restoration, thus reducing restoration costs and revenue loss, even on circuits that are predominantly overhead as well. It is not clear why these devices are not being installed under current programs.

D. Underground Mitigation Programs

Q37. Please address the proposed incremental underground mitigation programs.

A37. These proposed programs deal with what the Company calls "proactive" replacement (or, some cases, the rejuvenation) of power cables and of underground residential distribution ("URD") cables. Power cables are used inside substations and for the underground portion of distribution circuits used in many substations to exit the immediate vicinity. URD is used primarily in residential subdivisions. Both types have useful service lives that are typically a bit shorter than those of overhead facilities. The proposed incremental program will provide for replacement of power cables on the basis of cable condition and operational history and for the rejuvenation or replacement of URD cable on the same basis. Since the decision to replace or treat cables is made largely after cables experience deterioration-related service interruptions, it is, perhaps, questionable just how proactive this approach can be considered.

Programs such as these are becoming increasingly common with utilities, but should be part of normal utility system maintenance. The replacement of facilities due to deterioration from age or use is not a special condition but is a part of maintaining and operating an electric utility system in prudent fashion. The dollars spent on current facilities are recovered by a utility through the depreciation component of rates and are available to contribute to the cost of replacement facilities.

E. Substation Programs

Q38. Please address the Company's proposed incremental distribution substation programs.

A38. The proposed incremental distribution substation program addresses installing protection against animal contacts with energized equipment inside substations, and replacing old, obsolete, and/or unserviceable circuit breakers and protective relays. Both of these programs should help address outages caused by faults inside substations, one of the Company's leading causes of service interruptions. However, it is not clear just how incremental the breaker and relay program are.

The replacement of old facilities is not a newly occurring requirement of operating a distribution system.

F. Automation and SCADA Programs

Q39. Please address the Company's proposed automation and SCADA programs.

A39. The Company's incremental plan includes the installation of distribution automation ("DA") switched at selected locations, as well as the installation of SCADA at some 160 substations that currently lack such capability. Distribution automation[33] and basic substation SCADA both involve the use remote sensing and remote control of various elements of the electric system.

Substation SCADA typically involves the ability to remotely control substation switches that energize or de-energize substation transformers, switches that control the flow of power within the substation, and breakers that control the flow of power out on distribution circuits, as well as the ability to remotely sense the status of major substation components. When there is a fault on a distribution circuit that results in the tripping of the substation breaker for that circuit, system operators would know almost immediately via SCADA that this trip had occurred, if the substation is SCADA equipped. Otherwise, operators would have to wait for customers served from that circuit to call the Company to report a loss of electricity before they know that the outage is occurring. The presence of

[33] True distribution automation typically goes beyond the use of sectionalizers or reclosers on distribution circuits.

SCADA shortens outage restoration time for customers. Typically, virtually all new substations are designed and built with SCADA capability.

The Company, however, currently has several hundred substations without SCADA capability. Since all customers pay for the SCADA capability that is installed, it is unequitable for so many substations to be without SCADA. These customers should be provided the benefits of substation SCADA before being asked to pay for others to receive the benefits from distribution automation.

Distribution automation provides remote sensing and remote control capabilities such that outages of distribution circuits can remotely and/or automatically be shortened by isolating faulted portions and the unfaulted portions of a distribution circuit and connecting the unfaulted portions of the circuit back to the system, thereby restoring service. DA normally will normally be installed only on circuits that have substation SCADA capability and then, only on those circuits whose configuration and load levels provide a significant enough benefit from DA to justify the additional expense of providing DA. The successful implementation of DA has the potential to provide a premium level of service reliability, but not necessarily to all customers. It seems premature to start installing such capability on a system where so many customers are still without SCADA capability. The Company should focus first on the installation of SCADA capability.

G. Summary

Q40. Please summarize AEP Ohio's proposed incremental reliability programs and your associated recommendations.

A40. The Self Complaint states that AEP Ohio would present a process that would describe program details, including service reliability impacts and associated costs. The Plan does not provide the information the Company proposed to provide in the Self Complaint. It is especially weak regarding service reliability impacts, and is short of program details in a number of areas, especially where the vegetation management program is concerned.

According to page 48 of the Plan, AEP Ohio admits it is not really committing to the Plan because a number of factors might affect the implementation of the Plan, such as labor availability, material resource constraints, and reliability challenges not yet identified. Even if I agreed with all aspects of the Plan as described, this may not be what is actually implemented.

The Plan provides for little in the way of reporting what is being done, what it is costing, and what reliability benefits are being realized, apart from the provision that, as work is completed, the Company will meet with Staff to review the actual work performed, the dollars spent, and the direct benefit. There needs to be established a reporting protocol that provides for regular Plan reports, which need to be available to parties other than just Staff, as well as an opportunity for others to formally comment on Plan management, modifications, spending, progress, and benefits.

VIII. SUMMARY

Q41. Please summarize your testimony and recommendations.

A41. My conclusions and recommendations are as follows:

1. System reliability performance (with major storms excluded), as reflected in AEP Ohio's reliability indices, has become less reliable, particularly in the area of outage frequency (SAIFI) and average outage minutes per year (SAIDI), prior to 2006.
2. System reliability index performance, with major storm data included, has become increasingly less reliability and more divergent from reliability indices with storm data excluded, especially in 2003 and 2004.
3. AEP Ohio's reliability index targets, especially those for outage frequency (SAIFI), keep getting less demanding, justified by the Company based on the fact that its reliability index performance in recent years has reflected lower reliability.
4. AEP Ohio installed an automated distribution system outage reporting system in the early 2000s to replace its system of manual data entry and handling of outage data. However, it apparently did so without benchmarking the effects of this system on its reliability indices by performing parallel runs for the old and new systems using the same data for the same time period. The Company

claims that this new technology has resulted in increases in its reliability indices (i.e. decreasing reliability), but, without parallel run verification, these increases in the reliability indices could just well be increasing, in whole or in part, because system reliability is getting worse.

5. Prior to 2006, AEP Ohio's reliability index targets have been moving in the direction of lower reliability, especially regarding outage frequency (SAIFI). The Company attributes this to the installation of its automated outage recording system, but without the parallel run benchmarking discussed in Item #4 above, these changes should be attributed in part or in their entirety to actual changes in system reliability.

6. Several of AEP Ohio's current reliability-related programs, including overhead circuit inspections and vegetation management, have been marked by large swings in the level of effort over the past four to five years, raising potential questions as to the consistency of the quality of these programs.

7. AEP Ohio's base vegetation management program is described in the Plan as performance-based, and I believe this has contributed to the deterioration in the Company's reliability index performance in 2003 and 2004, especially during major storms, as well as the need to spend in excess of $90 million over 2004 and 2005 for catch-up vegetation management.

8. AEP Ohio's incremental vegetation management program promises to inspect or trim all of its distribution circuits once during the next four years. However, the need to double the number of crews over five years, before reducing the number of these crews, raises questions to whether a more consistent level of vegetation management effort would be more sustainable and effective.

9. A program to deal with trees outside the right-of-way needs to be specified and made part of the vegetation management effort.

10. The incremental overhead line inspection program does not appear to be significantly different from the Company's existing program.

11. Parts of the Company's overhead mitigation program appears to represent incremental efforts that address significant reliability concerns regarding fuse cutouts and lightning arrestors that have been demonstrating increasing failure rates. The 34.5 kV program, however, while laudable, does not reflect an incremental effort.

12. The parts of the incremental reliability programs that deal with the replacement of aging equipment should not be considered as incremental to normal utility practice.

13. The installation of SCADA capability in those substations which do not currently have it should take precedence over more sophisticated distribution automation efforts.

14. The Plan appears deficient in several areas addressing implementation details, expected reliability benefits, formalized reporting, and regulatory review.

Q42. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A42. Yes. However, I reserve the right to modify, amend, or add to this testimony based on additional information that may become available.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the Supplemental Testimony of Peter J. Lanzalotta by the Office of the Ohio Consumers' Counsel was served by first class United States Mail, postage prepaid, to the persons listed below, on this 10th day of April 2007.

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