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April 1, 2015

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HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RECEIVED
APR 01 2015
PUBLIC SERVICE
COMMISSION

RE: Case No. 2014-00479

Dear Mr. Derouen:

Enclosed please and find accept for filing the original and ten copies of Kentucky Power Company's responses to Staff's data requests. Also being filed are the Company's motion for confidential treatment and the confidential version of Attachment 1 to the Company's response to Staff 1-9.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 01 2015
PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR: (1) AN ORDER DECLARING AND CLARIFYING THE APPLICATION OF THE INSPECTION REQUIREMENTS OF 807 KAR 5:006, SECTION 26(4), TO CERTAIN OF THE COMPANY'S TRANSMISSION FACILITIES; OR (2) IN THE ALTERNATIVE, AND TO THE EXTENT REQUIRED, A DEVIATION IN PART FROM THE INSPECTION REQUIREMENTS OF 807 KAR 5:006, SECTION 26(4), WITH RESPECT TO THE COMPANY'S TRANSMISSION FACILITIES; AND (3) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO: 2014-00479

<u>PETITION FOR CONFIDENTIAL TREATMENT</u>

Kentucky Power Company ("Kentucky Power" or "Company") moves the Commission pursuant to 807 KAR 5:001, Section 13, for an Order granting confidential treatment for the identified portions of the Company's responses to Request No. 9 in the Commission Staff's First Request for Information ("Commission Staff 1-9"). Kentucky Power is complying with its obligations under 807 KAR 5:001, Section 13(2)(e) with respect to the filing of a redacted and unredacted response to this request.

A. <u>The Requests and the Statutory Standard.</u>

Kentucky Power does not object to producing the identified information for which it is seeking confidential treatment, but requests that the identified portions of the response be excluded from the public record and public disclosure. The confidential information at issue in this proceeding is protected from public disclosure under the Kentucky Open Records Act ("Act"). KRS 61.878(c)(1) excludes from the Act:

> Upon and after July 15, 1992, records confidentially disclosed to an agency or required to be disclosed to it, generally recognized as

> confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records.

Additionally, KRS 61.878(m)(1)(f) excludes from the act:

> Public records the disclosure of which would have a reasonable likelihood of threatening the public safety by exposing a vulnerability in preventing, protecting again, mitigating, or responding to a terrorist act and limited to . . . Infrastructure records that expose a vulnerability referred to in this subparagraph through the disclosure of the location, configuration, or security of critical systems, including public utility critical systems.

Kentucky Power seeks confidential treatment of its response to Commission Staff 1-9 because it falls within these exceptions to the Act.

Kentucky Power seeks confidential treatment of its response to Commission Staff 1-9 because it contains confidential customer-specific information.[1] Kentucky Power does not release customer-specific information to the public, and these customers expect the Company to protect the confidentiality of the information. These customers operate in competitive national and/or global markets. Releasing the identity of specific customer facilities will allow competitors to gain information regarding the production costs of these customers' goods and services.[2] This information would not otherwise be known in the competitive marketplace, and the public disclosure will place Kentucky Power's customers at a distinct competitive disadvantage. As a result of this competitive disadvantage, commercial and industrial customers will be less likely to locate in Kentucky Power's service territory, which will result in harm to Kentucky Power. The Commission has recognized the confidentiality of customer information

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[1] Commission Staff 1-9 provides: "Are there any points of service or other electric service arrangements that directly utilize electricity for the 34.5-kV or 46-kV electric facilities? If so, identify each point of service or other electric service arrangement."

[2] The information at issue provides the identity of specific industrial customers as the identity of specific service lines and servicing stations or taps utilized to provide service to those customers. Coupled with the names and voltage of the service line and switching station or service tap, the information could be used by the customers' market competitors to determine electricity usage, and thus offers valuable insight into their production costs for goods and services.

in previous cases and the Company asks that it follow that precedent here. Specifically, Kentucky Power requests that this information be afforded confidential treatment for a period of at least ten years.

Additionally, public disclosure of the information contained in the Company's response to Commission Staff 1-9 constitutes critical energy infrastructure information and its release would have a reasonable likelihood of threatening public safety. Information about industrial customer service including the voltage, name of the line, and the fact that the customer is served directly from a single transmission line would be useful to potential wrongdoers. This information is treated as confidential by FERC in the context of AEP's Form 715 filings. The information is not publicly available, and parties interested in reviewing asset information related to voltage, name, and location of lines is required to sign a non-disclosure agreement. Kentucky Power requests that the Commission follow a similar approach here and treat this information as confidential for a period of at least ten years.

B. <u>The Identified Information is Generally Recognized as Confidential and Proprietary and is Protected from Public Disclosure by Kentucky Power.</u>

The identified information required to be disclosed by Kentucky Power in response to the data request at issue is highly confidential. Dissemination of the information for which confidential treatment is being requested is restricted by Kentucky Power, AEP, and AEPSC. The Company, AEP, and AEPSC take all reasonable measures to prevent its disclosure to the public and the information is not disclosed to third parties. Within Kentucky Power, AEP, and AEPSC, the information is available only upon a confidential need-to-know basis that does not extend beyond employees with a legitimate business need to access and act upon the information. The information is not otherwise accessible to employees of Kentucky Power, AEP, or AEPSC.

C. The Identified Information is Required to be Disclosed to an Agency.

The identified information is required to be disclosed to the Commission and the Commission is a "public agency" as that term is defined at KRS 61.870(1). Any filing should be subject to a confidentiality order and any party requesting the information should be required to enter into an appropriate confidentiality agreement.

Wherefore, Kentucky Power respectfully requests the Commission enter an Order:

1. Affording confidential status to and withholding from public inspection the identified information; and

2. Granting Kentucky Power all further relief to which it may be entitled.

Respectfully submitted,

Mark R. Overstreet
R. Benjamin Crittenden
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COUNSEL FOR KENTUCKY POWER COMPANY

RECEIVED

APR 01 2015

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

AN APPLICATION OF KENTUCKY POWER	)
COMPANY FOR: (1) AN ORDER DECLARING	)
AND CLARIFYING THE APPLICATION OF THE	)
INSPECTION REQUIREMENTS OF 807 KAR 5:006,	)
SECTION 26(4), TO CERTAIN OF THE COMPANY'S	)
TRANSMISSION FACILITIES; OR (2) IN THE	)
ALTERATIVE, AND TO THE EXTENT REQUIRED,	) **Case No. 2014-00479**
A DEVIATION IN PART FROM THE INSPECTION	)
REQUIREMENTS OF 807 KAR 5:006, SECTION 26(4),	)
WITH RESPECT TO THE COMPANY'S TRANSMISSION	)
FACILITIES; AND (3) ALL OTHER REQUIRED	)
APPROVALS AND RELIEF	)

KENTUCKY POWER COMPANY RESPONSES TO
COMMISSION STAFF'S FIRST SET OF DATA REQUESTS

April 01, 2015

VERIFICATION

The undersigned Everett G. Phillips, being duly sworn, deposes and says he is the Managing Director, Distribution Region Operations for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing data requests and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Everett G Phillips

Everett G Phillips

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2014-00479
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Everett G. Phillips, this the 23RD day of March, 2015.

Notary Public #440439

My Commission Expires: 4/5/2015

VERIFICATION

The undersigned, John A. Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his/her information, knowledge and belief.

John A. Rogness III

COMMONWEALTH OF KENTUCKY)
) Case No. 2014-00479
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A. Rogness III, this the 31st day of March, 2015.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

State the factors that Kentucky Power believes are relevant in classifying its 34.5-kV lines as transmission facilities.

RESPONSE

Kentucky Power uses the Federal Energy Regulatory Commission (FERC) the Uniform System of Accounts definition of transmission system in classifying the subject 34.5 kV lines as transmission facilities. It provides:

A. Transmission system means:

(1) All land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission;

(2) All land, structures, lines, switching and conversion stations, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and

(3) All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.

B. Distribution system means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

Note: Stations which change electricity from transmission to distribution voltage shall be classified as distribution stations.

Under the FERC guidelines, the use made of a line is the defining characteristic of how a line is classified. The subject 34.5 kV lines and 46 kV lines function as and hence are designated as transmission lines. These transmission lines are configured as part of the Kentucky networked transmission grid to augment, integrate or tie together the sources of power supply and to transport that power to switching and conversion stations in order to supply power into the Company's distribution system.

Upon further review, the Company has determined there are approximately 2 miles of 34.5 kV line in the Company's service territory functioning and classified as transmission facilities. The Application originally stated that there were approximately 10 miles of 34.5 kV line functioning and classified as transmission facilities.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Are the 34.5-kV electric facilities inspected on the same schedule as facilities operating at or above 69 kV? If not, explain in detail the inspection schedule and types of inspections performed on the 34.5-kV facilities.

RESPONSE

Yes. The 34.5 kV transmission electric facilities are inspected on the same schedule as facilities operating at or above 69 kV.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

State the factors that Kentucky Power believes are relevant in classifying its 46-kV lines as transmission facilities.

RESPONSE

Please see the Company's response to KPSC 1-1.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Are the 46-kV electric facilities inspected on the same schedule as facilities operating at or above 69 kV? If not, explain in detail the inspection schedule and types of inspections performed on the 46-kV facilities.

RESPONSE

Yes. The 46 kV transmission electric facilities are inspected on the same schedule as facilities operating at or above 69 kV.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Are the construction standards utilized for the approximate ten miles of 34.5-kV electric facilities the same as those utilized for electric facilities operating at or above 69 kV? Identify in the response any difference in construction standards.

RESPONSE

For new construction, 34.5 kV facilities are built to 69 kV transmission construction standards. At the time each of the subject 34.5 lines were constructed or rebuilt, the then applicable construction standards were employed, which met or exceeded the requirements of the National Electric Safety Code (NESC).

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Are the construction standards utilized for the 166 miles of 46-kV electric facilities the same as those utilized for electric facilities operating at or above 69 kV? Identify in the response any difference in construction standards.

RESPONSE

For new construction, 46 kV facilities are built to 69 kV transmission construction standards. At the time each of the 46 kV lines were constructed or rebuilt, the then applicable construction standards were employed, which met or exceeded the requirements of the National Electric Safety Code (NESC).

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

State the vegetation management plan and practices for the approximate ten miles of 34.5-kV electric facilities. Identify in the response any vegetation management practice for these facilities that differs from vegetation management practices for transmission facilities operating at or above 69 kV. Provide all documentation supporting the response.

RESPONSE

Kentucky Power's Transmission Vegetation Management Program ("TVMP") is a comprehensive vegetation management program for pruning and clearing vegetation along transmission circuits to protect lines in an environmentally sound and cost-effective manner. KPCo uses vegetation management practices to control vegetation along its transmission rights-of-way ("ROW"), such as aerial sawing, mechanized trimming, manual trimming (roping and hand climbing), mechanized clearing, manual clearing and herbicide applications.

The Company currently uses a performance-based annual plan approach on all transmission circuits below 200 kV. For lines above 200 kV, Kentucky Power employs a flexible and dynamic cycle-based approach for transmission vegetation management above. The TVMP was developed to ensure compliance with the North American Electric Reliability Corporation ("NERC") reliability standard FAC-003-3.

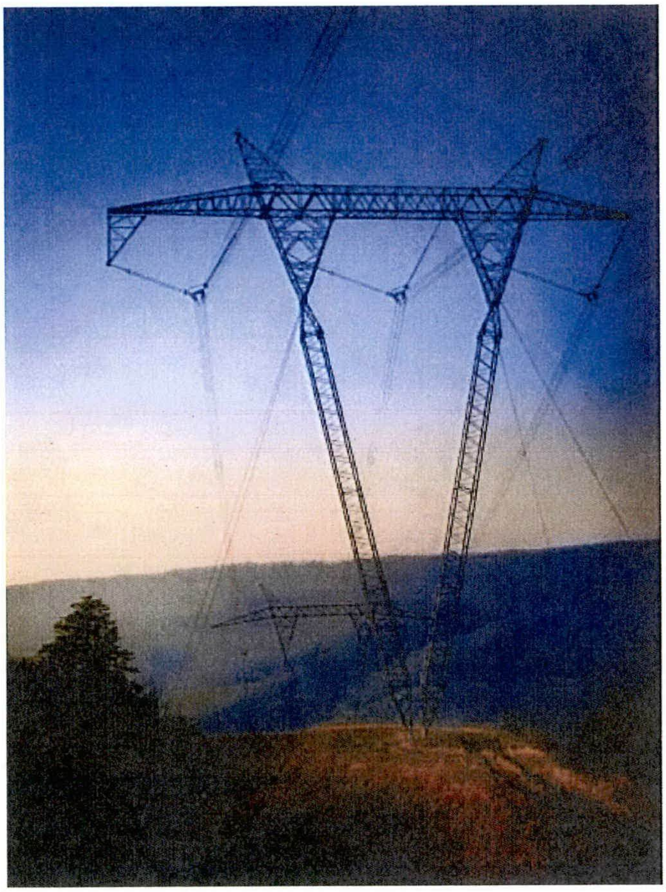
A performance-based approach for transmission ROW below 200 kV allows Kentucky Power to address the circuits with the greatest need of vegetation management. At the end of each year, the following year's plan is developed based on year-end circuit performance. The annual vegetation management work plans are flexible and dynamic. Inputs to these work plans come from the Company's visual inspections, which are part of its annual assessment, historical reliability data, line inspections, customer density, circuit performance, weather, customer complaints and the amount of time elapsed since vegetation management was last performed.

A copy of the Company's Transmission Vegetation Management Program is provided in KPSC 1-7 Attachment 1.

WITNESS: Everett G Phillips

Transmission Vegetation Management Program (TVMP)

Effective July 31, 2014



Review Cycle

Version	Description	Review Cycle	Retention Period	Review Date
1	Reviewed with Changes to Ver. 0.	Annual	3 Yrs	01/16/2006
2	Reviewed with Changes to Ver. 1 and 2.	Annual	3 Yrs	03/12/2007
5	Reviewed with Changes to Ver. 3, 4, and 5.	Annual	3 Yrs	05/06/2008
8	Reviewed with Changes to Ver. 6.	Annual	5 Yrs	05/26/2009
9	Reviewed with Changes to Ver. 8.	Annual	5 Yrs	07/27/2010
10	Reviewed with Changes to Ver. 9.	Annual	5 Yrs	07/21/2011
11	Reviewed with Changes to Ver. 10.	Annual	5 Yrs	07/12/2012
12	Reviewed with Changes to Ver. 11.	Annual	5 Yrs	07/15/2013
13	Reviewed with Changes to Ver. 12.	Annual	5 Yrs	07/18/2014

Revision History

Version	Description	Prepared By	Reviewed By	Approved By	Effective Date
1	Added Appendixes A and B.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	01/16/2006
2	Added Appendix C.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	10/02/2006
3	Added Revision History.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	03/12/2007
3	Revised Appendix C from Version 2. Clarified video text associated with aerial patrols, page 8.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	03/22/2007
4	Revised Maintenance Clearances in Table I, page 11. Removed Appendix A from Revision 0 and inserted a new Appendix A. Removed Appendix B from Revision 0 and renamed Appendix C from Revision 0 to Appendix B.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	11/09/2007
5	Revised Maintenance Clearances text page 10. Revised Appendix B.	H.R. Jones, Principal Engineer	-	J. E. Schechter, Mgr., Trans. Line Asset Engineering	05/06/2008

Version	Description	Prepared By	Reviewed By	Approved By	Effective Date
6	Added third level of review/approval. Added Internal Mailing list. Added Standard mapped to TVMP. Revised Contents and page numbers. Revised Maintenance Clearances, pages 13 and 14. Revised Imminent Threat, pages 10 and 11. Revised Appendix A. Added new Appendix C. Added new Appendix D. Added hyperlinks.	S .J. Reaves, Forestry Program Coordinator I	J. E. Schechter, Mgr., Trans. Line Asset Engineering	D. R. Boezio, Dir., Trans. Asset Engineering	06/15/2009
8	Revised Version History. Revised Personnel Qualifications, Appendix D. Included References on Contents Page. Revised Subject Matter Experts (SMEs).	S .J. Reaves, Forestry Program Coordinator I	J. E. Schechter, Mgr., Trans. Line Asset Engineering	D. R. Boezio, Dir., Transmission Asset Engineering	07/31/2009
9	Revised Reviewer and Approval List. Revised TVMP Internal Mailing List. Changed Landowner and Community Relations section to Land Owner Relationships and Environmental Sustainability. Revised Subject Matter Experts (SMEs). Revised Personnel Directly Involved.	D.K. Killingsworth, Engineer I	J. E. Momme, Dir., Trans. Line Projects Engineering	D. J. Recker, Managing Dir., Trans. Projects Engineering	07/30/2010
10	Reformatted Document to match Transmission Forum Model TVMP.	D.K. Killingsworth, Engineer I	J. E. Momme, Dir. Trans. Line Projects Engineering	D. J. Recker, Managing Dir. Trans. Projects Engineering	7/30/2011

Version	Description	Prepared By	Reviewed By	Approved By	Effective Date
11	Revised Reviewer and Approval List. Revised TVMP Internal Mailing List. Changed Land Owner Relationships and Environmental Sustainability to Land Owner Relationships and revised. Revised Subject Matter Experts (SMEs). Revised Personnel Directly Involved. Removed Appendix C. Revised Personnel Qualifications. Revised New Construction Clearing. Added Document Team.	K. B. Patton, Utility Forester II	J. E. Momme, Dir., Trans. Line Projects Engineering	D. J. Recker, Managing Dir., Trans. Projects Engineering	7/31/2012
12	Revised Document Team. Revised Subject Matter Experts (SMEs). Revised Appendix A Imminent Threat Communication and Procedures. Revised Appendix B Imminent Threat Communication. Revised Appendix C TVMP Internal Mailing List. Revised Forestry Patrol Procedures. Revised Imminent Threat Report Form.	K. B. Patton, System Forestry Coordinator	J. E. Momme, Dir., Trans. Line Projects Engineering	D. J. Recker, Managing Dir., Trans. Projects Engineering	7/30/2013
13	Revised Document Team. Revised Signature page. Updated References. Revised entire document to align with changes to NERC Standard FAC-003-3. Revised Personnel Directly Involved. Moved Right-of-Way Clearance Guidelines to Appendix A. Updated Appendix C: Subject Matter Experts. Revised Appendix D TVMP Internal Mailing List.	Lynn Hayward Lead Engineer	J. E. Momme, Dir., Trans. Line Projects Engineering	J. E. Momme, Dir., Trans. Line Projects Engineering	7/31/2014

Signatures

Prepared By

Lynn E. Hayward Lead Engineer, Transmission Line Engineering	07-24-14 Date

Approved By

Walter A. Sherry, Jr. Manager, Forestry Operations	24 July 14 Date
Jeffrey E. Momme, P.E. Director, Transmission Line Engineering	7-25-14 Date
Daniel J. Recker, P.E. Managing Director, Transmission Projects Engineering	7/28/14 Date
Scott Moore, P.E. Vice President, Transmission Engineering & Project Services	7/29/14 Date
Scott N. Smith Senior Vice President, Transmission Grid Development & Portfolio Services	7/29/14 Date

Document Team

Barrett A. Thomas, Engineer I, Transmission Line Engineering
Benjamin Bradburn, Utility Forester II, Transmission Forestry
Eric K. Engdahl, P.E., Staff Engineer, Transmission Line Standards
H. Lynn Grayson, Consultant
Jacqueline M. Rich, Engineer II, Transmission Line Engineering
James G. Cruser, Supervisor, Region Forestry, Transmission Forestry
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Mark Boucher, Utility Forester II, Transmission Forestry
Richard L. Karber, Supervisor, Region Forestry, Transmission Forestry
Rick Mowbray, Supervisor, Region Forestry, Transmission Forestry
Robert Whitaker, Engineer I, Transmission Line Engineering
Walter A. Sherry Jr., Manager, System Forestry Operations

Table of Contents

I. Referenced Specifications

Title	Date	Version	Pages
AEP Forestry Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations	2009		
American Electric Power (AEP). *Transmission Right of Way Clearing and Maintenance: A Balanced Approach to Vegetation Management*. American Electric Power, Columbus, OH 43215.	2008		
American National Standard Institute. *for Tree Care Operations - Tree, Shrub, and Other Woody Plant Management - Standard Practices (Pruning)*. Tree Care Industry Association, Inc. Londonderry, NH 03053.	2008	A300 (Part 1)-2008	1–13
American National Standard Institute. *for Tree Care Operations - Tree, Shrub, and Other Woody Plant Management - Standard Practices* Part 7 – Integrated Vegetation Management a. Electric Utility Rights-of-way. Tree Care Industry Association, Inc. Londonderry, NH 03053.	2012	A300 (Part 7)-2012	1–15
American National Standard Institute. *for Tree Care Operations - Tree, Shrub, and Other Woody Plant Management - Standard Practices* Part 7 – Integrated Vegetation Management a. Electric Utility Rights-of-way. Tree Care Industry Association, Inc. Londonderry, NH 03053.	2006	A300 (Part 7)-2006	57–66
American National Standard Institute. *American National Standards for Arboriculture Operations – Safety Requirements*. International Society of Arboriculture (ISA). Champaign, IL 61826.	2012	Z133.1-2012	1–71
IEEE 516-2003. Institute of Electrical and Electronics Engineers, Inc. *IEEE Guide for Maintenance Methods on Energized Power Lines*. Institute of Electrical and Electronics Engineers, Inc. New York, NY 10016-5997.	2003		1–119
AEP Guideline Accounting for Maximum Conductor and Sag Blowout for Vegetation Management	2014		
AEP Transmission Forestry Aerial Patrol Procedures for NERC-Reportable Circuits	2013		
AEP Risk Assessment & Procedures	2011		

II. The Transmission Vegetation Management Program (TVMP)

A. Scope

The American Electric Power (AEP) Transmission Vegetation Management Program (TVMP) has been developed and implemented to ensure compliance with the North American Electric Reliability Corporation (NERC) reliability standard FAC-003-3. This program is intended to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights-of-way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

This program applies to AEP's transmission and generation facilities as defined in FAC-003-3. Facilities referred to as NERC-applicable are:

- Transmission or generation lines operated at 200 kV and above (≥200kV);
- Other lower-voltage transmission or generation lines that have been designated as an Interconnection Reliability Operating Limit (IROL);
- Each overhead transmission line identified above, located outside the fenced area of the switchyard, station or substation, and any portion of the span of the transmission line that is crossing the substation fence;
- Overhead generation lines that extend greater than one mile beyond the fenced area of the generating station switchyard to the point of interconnection with a transmission facility;
- Generation leads that do not have a clear line of sight.

AEP's Transmission Forestry Operations group manages and executes the program for vegetation along approximately 8,700 miles of NERC-applicable transmission rights-of-way in portions of eleven states. This is accomplished through the implementation and oversight of a comprehensive, systematic, vegetation management program.

B. Vegetation Management Objectives

The TVMP is an integral part of providing for the safe, reliable operation of the AEP transmission system. The key measure of success is zero reportable vegetation-related outages on NERC-applicable facilities.

For NERC-applicable facilities, AEP's intent is to clear the right-of-way to the maximum appropriate width by removing all woody-stemmed vegetation within the right-of-way[1] and potential hazard trees.

AEP conducts inspections, aerial and as-needed ground inspections, and develops annual vegetation management work plans to ensure the program objective is achieved in the most efficient, environmentally sound, and economical manner practical.

[1] Upon completion of vegetation maintenance.

AEP strives to manage its rights-of-way in accordance with its Environmental, Safety and Health (ES&H) Philosophy: "No aspect of operations is more important than the health and safety of people. Our customer's needs are met in harmony with environmental protection."

Other considerations include:

- Minimizing adverse environmental impacts.
- Complying with laws and regulations.
- Achieving cost efficiency.
- Maintaining a positive relationship with landowners and the public.

C. Definitions

Cascading: "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."[2]

Hazard trees: Those trees that are structurally unsound and could strike a target (such as electric facilities) when they fail.[3]

Interconnection Reliability Operating Limit (IROL): "A system Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."[2]

Inspector: Individual assigned with the responsibility of evaluating clearances in the Transmission Right-of-Way and minimizing encroachments into the ROW from vegetation located adjacent to the ROW.

Minimum Vegetation Clearance Distance (MVCD): "The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages."[2]

Remediation: The evaluation of a point of interest, and if necessary, taking action to resolve the identified vegetative issues.

Right-of-Way (ROW): "The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria."[2]

Sustained Outage: "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure."[2]

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[2] North American Electric Reliability Corporation, *Glossary of Terms Used in NERC Reliability Standards* (Atlanta, GA: North American Electric Reliability Corporation, 2014), accessed July 18, 2014, http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[3] American National Standard Institute, "Part 7 – Integrated Vegetation Management," "a. Electric Utility Rights-of-way" in *for Tree Care Operations - Tree, Shrub, and Other Woody Plant Management - Standard Practices*, (Londonderry, NH: 2006), 58.

Vegetation Inspection: "The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection."[4]

WECC Transfer Path: The transmission paths monitored by the WECC (Western Electric Coordinating Council) regional Reliability coordinators.[4] Note: AEP does not operate in the WECC region.

III. FAC-003-3 Requirements

A. Requirement 1 (Applicable Lines That are an Element of an IROL or Major WECC Transfer Path)

AEP maintains records of sustained outages from all causes. All outages determined to be caused by vegetation are investigated by appointed AEP employees, and information is obtained specific to the line designation, voltage, date and time of the disturbance, species, location relative to the line, NERC outage category, and duration of the outage if it was sustained. Sustained transmission line outages that are determined to have been caused by vegetation are reported to the Regional Entities or their designees. The supporting document AEP utilizes to identify vegetation outage information is a periodic report generated from an internal AEP system. The report lists vegetation-related outages by Regional Entities. The report lists the names of circuits where outages occurred; operated voltages; the date, time, and duration of the outage; and a description of the cause of the outage.

AEP conducts bi-annual vegetation inspections of all applicable facilities. During this inspection AEP inspects the vegetation-to-conductor clearances and identifies vegetation on and along transmission ROWs that could pose a reliability risk to the facility. Aerial patrols, except where the FAA or other ordinance prohibits flight, cover substantial portions of the transmission system to identify areas where remediation may be needed to prevent vegetation from interfering with circuit operation. Ground patrols are used to supplement aerial patrols and where aerial patrols are restricted.

A confirmed encroachment into the MVCD as shown in FAC-003-3 Table 2, observed in Real time during the inspection, is reported to the transmission forestry manager. Appropriate data and photographs are taken and submitted to the manager. These events are reported to the Regional Entity in accordance with NERC policy.

[4]North American Electric Reliability Corporation, Glossary of Terms Used in NERC Reliability Standards (Atlanta, GA: North American Electric Reliability Corporation, 2014), accessed July 18, 2014, http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

B. Requirement 2 (Applicable Lines That are Not an Element of an IROL or Major WECC Transfer Path)

AEP maintains records of sustained outages from all causes. All outages determined to be caused by vegetation are investigated by appointed AEP employees, and information is obtained specific to the line designation, voltage, date and time of the disturbance, species, location relative to the line, NERC outage category, and duration of the outage if it was sustained. Sustained transmission line outages that are determined to have been caused by vegetation are reported to the Regional Entities or their designees. The supporting document AEP utilizes to identify vegetation outage information is a periodic report generated from an internal AEP system. The report lists vegetation-related outages by Regional Entities. The report lists the names of circuits where outages occurred; operated voltages; the date, time, and duration of the outage; and a description of the cause of the outage.

AEP conducts bi-annual vegetation inspections of all applicable facilities. During this inspection AEP inspects the vegetation-to-conductor clearances and identifies vegetation on and along transmission ROWs that could pose a reliability risk to the facilitiy. Aerial patrols, except where the FAA or other ordinance prohibits flight, cover substantial portions of the transmission system to identify areas where remediation may be needed to prevent vegetation from interfering with circuit operation. Ground patrols are used to supplement aerial patrols and where aerial patrols are restricted.

A confirmed encroachment into the MVCD as shown in FAC-003-3 Table 2, observed in real time during the inspection, is reported to the transmission forestry manager. Appropriate data and photographs are taken and submitted to the manager. These events are reported to the Regional Entity in accordance with NERC policy.

C. Requirement 3 (Maintenance Strategy)

For NERC-applicable facilities, AEP's fundamental strategy is to clear the right-of-way to the maximum appropriate width by removing all woody-stemmed vegetation within the right-of-way[5] and potential hazard trees.

AEP considers conductor locations, the MVCD, and vegetation growth between maintenance activities when developing its maintenance plan. Maintenance does not occur on a rigid "cycle" basis; rather, the maintenance technique and schedule are driven by the condition of the vegetation observed during bi-annual inspections. Vegetation-to-conductor distances are based on completed work meeting or exceeding the minimum approach distances to energized conductors for persons other than qualified line-clearance arborists and qualified line-clearance arborist trainees (Columns A and C in Table 3: Transmission Line Clearance Guidelines in Appendix A on page 19).

AEP Transmission Forestry's goal is to convert the vegetative cover types on its transmission rights-of-way to low growing grass-forbs-herb covers that inhibit the germination, establishment, and growth of most incompatible vegetative species.

The AEP transmission vegetation management program emphasizes tree removal to promote long-term vegetation control and to minimize future maintenance expenditures. Additionally, AEP foresters and contractor personnel inspect for hazard trees during scheduled maintenance. Hazard trees are addressed on a case-by-case basis by the responsible forester.

[5] Upon completion of vegetation maintenance.

Manual clearing is employed where the terrain is too steep or rough for mechanized equipment, where the vegetation is too tall for herbicide applications and aerial application is not possible, or where the immediate removal of vegetation is necessary. Contract employees use chainsaws or brush saws to selectively remove vegetation from the rights-of-way.

Mechanical clearing may be employed where terrain and access allow and where the vegetation is not too large for mechanical equipment to handle, where the vegetation is too tall for herbicide applications, where aerial application is not possible, or where the immediate removal of vegetation is necessary.

When tree removal or clearing is not practical or feasible, tree pruning may be employed. Fast-growing trees, where removal permission is not obtained, are pruned to yield greater clearance distances than slower-growing varieties. AEP Transmission Forestry may employ tree growth regulators (TGRs) to reduce the frequency and amount that trees must be pruned.

Mechanical pruning operations employ a variety of boom-mounted saws on vehicles capable of traversing the rights-of-way. Access, terrain, and tree heights influence the type of equipment used. When applicable, rights-of-way may be maintained with an aerial saw. These rights-of-way possess one or more of the following charactereistics: steep, mountainous terrain; limited access; or prohibitive costs to prune by convential means.

Manual and mechanical clearing without follow-up herbicide applications does not control the root systems of incompatible vegetation and could increase the future maintenance requirements in the areas where it is employed. Aerial, high-volume foliar, low-volume foliar, ultra-low-volume foliar, cut stubble, stump, basal, and granular applications may be employed. United States EPA-registered herbicides are applied by licensed pesticide application businesses contracted by AEP.

D. Requirement 4 (Vegetation Condition That is Likely to Cause a Fault at any Moment)

A vegetation condition that is likely to cause a fault at any moment is considered an imminent threat to the reliable operation of a NERC- or an IROL-applicable facility. An imminent threat must be mitigated within 24 hours of confirmation. This condition may be characterized by either vegetation or hazard trees that are approaching or threatening to approach the MVCD to the conductor. For locations found during patrols, routine work, or other observations, where a potential imminent threat condition is confirmed by transmission forestry, an immediate notification[6] to the local dispatching authority is required. This will allow for mitigating actions, such as removal of the vegetation, temporary reduction in circuit rating, or switching the circuit out of service, until the imminent threat is relieved.

Refer to Appendix B: Imminent Threat Communication and Procedures, which starts on page 20.

[6]NOPR RM-12-4-000, pg 50, #85 (10/18/2012)—NERC explains that the obligation to notify without intentional delay generally "can be understood to include an immediate (within 1 hour of observation) communication notwithstanding a safety issue to personnel, other immediate priority maintenance functions to ensure reliability or system stability, or communication equipment failures that precludes immediate communication."

E. Requirement 5 (Vegetation Constraint May Lead to an Encroachment Into the MVCD)

Restrictions on scheduled work may include refusals by property owners to access or perform work, orders to stop work by local authorities, or restrictions by federal and state agencies. The maintenance strategy in section III.C defines the expected extent of clearing. If the clearance specifications cannot be achieved at the time of scheduled maintenance, AEP shall implement corrective action. This corrective action may include more-frequent maintenance or more-frequent inspections to monitor the risk to the system and is documented in AEP's restriction log.

AEP has implemented procedures for achieving sufficient clearances in those locations on its rights-of-way where AEP is restricted from attaining Clearance 1 listed in Column C of Table 3: Transmission Line Clearance Guidelines to prevent encroachment into the MVCD. This is described in AEP's Right-of-Way Clearance Guidelines; see "Appendix A: Right-of-Way Clearance Guidelines," which starts on page 18.

During bi-annual patrols, AEP monitors locations where these clearances cannot be achieved and determines if more-frequent maintenance is required in order to assure the safe, reliable operation of the circuit.

F. Requirement 6 (Annual Inspections)

1. Vegetation Inspections and Patrols

Aerial patrols are conducted to identify areas of the transmission system where remediation may be needed to prevent vegetation from interfering with circuit operation except where the FAA or other ordinance prohibits flight. Ground patrols are used to supplement aerial patrols and where aerial patrols are restricted. Aerial and ground patrol inspections aid in the development of the vegetation maintenance work plan.

2. Forestry Patrol Procedures

a. Patrol of the AEP Transmission System

AEP shall perform bi-annual inspections on 100% of all transmission facilities subject to FAC-003-3. Patrols provide Transmission Foresters a view of right-of-way conditions and the effectiveness of the vegetation management program.

b. Patrol Schedule

Patrol schedules are summarized in the table below.

Table 1: Patrol Schedule

	Fall Patrol	Spring Patrol
Patrol	• Aug 15–Nov 15.	• By May 21. • In areas at higher elevation or with later vegetation emergence, this date may be extended to June 4.
Remediation	• A1 Condition: addressed within 24 hours of confirmation. • P1 Condition: complete by March 1 of the following year.	• A1 Condition: addressed within 24 hours of confirmation. • P1 Condition: complete by May 30. In areas at higher elevation or with later vegetation emergence, this date may be extended to June 14.

3. Exceptions

Aerial patrols may be interrupted by force majeure, such as severe storms or floods. If patrols are interrupted, the time extension to complete the inspection shall not exceed the duration of the time AEP was prevented from performing the vegetation inspection.

G. Requirement 7 (Annual Work Plan)

AEP shall complete 100% of its annual vegetation work plan miles on NERC-applicable facilities to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The work plan starts on January 1 and ends on December 31.

AEP has a process for documenting the vegetation management activities to ensure the following:

- Scheduled work is properly identified and listed in the work plan.
- Adjustments to the work plan are properly noted and recorded. This plan may be modified for the following reasons:
  - Change in expected growth rate/environmental factors
  - Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner
  - Rescheduling work between growing seasons
  - Crew or contractor availability/mutual assistance agreements
  - Identified unanticipated high-priority work
  - Weather conditions/accessibility
  - Permitting delays

  - Land ownership changes/change in land use by the landowner
  - Emerging technologies
- Timesheets and maintenance methods employed are noted for each type of work on each project listed in the work plan.
- Work quality inspections are performed and work completed meets company specifications.

Appendix A: Right-of-Way Clearance Guidelines

When performing maintenance, the objective for locations on spans with less than 100' vertical clearance at maximum sag from conductor to ground is removal of all woody-stemmed vegetation to the appropriate width[7], leaving the cleared area of the right-of-way populated with grasses and herbaceous growth. Under certain circumstances (unique topographic and/or environmentally sensitive conditions), AEP may allow compatible, low-growing species to remain in the right-of-way. In maintained areas (mowed yards, lawns, and public areas), trees deemed compatible with safe operation of the line may remain, although AEP strongly discourages this practice. Compatible species will be limited to those that grow no more than 15' tall. Actively maintained trees that could be considered a crop such as in nurseries or orchards will be maintained in accordance with the clearance table guidelines specified in Table 2: Clearance Table Guidelines below. Table 3: Transmission Line Clearance Guidelines on page 19 shows Transmission Line Clearance Guidelines.

Table 2: Clearance Table Guidelines

Right-of-Way with No Restrictions	Right-of-Way With Restrictions
< 100' Vertical Clearance Between Conductors at Maximum Sag and Ground	**< 100' Vertical Clearance Between Conductors at Maximum Sag and Ground**
1. Remove all woody stemmed vegetation2. 2. Do not allow vegetation closer than column E, Table 3. 3. Trigger distance to schedule maintenance per column D, Table 3.	1. Trim or remove vegetation to meet column C, Table 3. 2. Do not allow vegetation closer than column E, Table 3. 3. Trigger distance to schedule maintenance per column D, Table 3.
> 100' Vertical Clearance Between Conductors at Maximum Sag and Ground	**> 100' Vertical Clearance Between Conductors at Maximum Sag and Ground**
1. Trim or remove vegetation to meet column B, Table 3. 2. Do not allow vegetation closer than column E, Table 3. 3. Trigger distance to schedule maintenance per column D, Table 3.	1. Trim or remove vegetation to meet column C, Table 3. 2. Do not allow vegetation closer than column E, Table 3. 3. Trigger distance to schedule maintenance per column D, Table 3.

[7]Upon completion of vegetation maintenance.

Table 3: Transmission Line Clearance Guidelines[8]

Column A	Column B	Column C	Column D	Column E	MVCD[9]
Nominal Voltage (kV phase to phase)	AEP Clearance 1 (no restrictions) Desired Clearance Between Conductor and Vegetation	AEP Clearance 1 (with restrictions) Desired Clearance between Conductor & Vegetation	ANSI[10] Clearance between Conductor & Vegetation	AEP Clearance 26 between Conductor & Vegetation	Over sea level up to 5,000 ft
765kV	45	35'00"	27'04"	14'00"	9'06"
500kV	45'	26'08"	19'00"	10'00"	6'01"
345kV	30'	20'05"	13'02"	7'06"	3'10"
230kV	30'	16'05"	7'11"	5'02"	3'08"
161kV[11]	25'	14'00"	6'00"	3'05"	2'06"
138kV[11]	25'	13'02"	5'02"	2'11"	2'02"
115kV[11]	25'	12'04"	4'06"	2'06"	1'09"
88kV[11]	25'	12'04"	4'06"	2'06"	1'06"
69kV	25'	10'09"	4'02"	2'06"	1'01"

[8]Conductor at maximum sag and movement.
[9]The distances in this Table are the minimums required by FAC-003-3 to prevent Flash-over; however, prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.
[10]ANSI Z133-2012.
[11]Such lines are applicable to this standard only if PC has determined such per FAC-014.

Appendix B: Imminent Threat Communication and Procedures

An imminent threat is a condition that threatens the reliable operation of a NERC-applicable line or a Regional Transmission Organization-applicable line and must be mitigated within 24 hours of confirmation. This condition is usually characterized by either vegetation or danger trees that are approaching or threatening to approach the minimum vegetation clearance distance to the conductor. For locations found during patrols, routine work, or other observations, where a potential imminent threat condition is confirmed by transmission forestry, an immediate notification[12] to the local dispatching authority is required. This will allow for mitigating actions, such as removal of the vegetation, temporary reduction in circuit rating, or switching the circuit out of service, until the imminent threat is relieved.

Regional Transmission Organizations (PJM, ERCOT, SPP RTO) grant utility operators the right to take emergency actions to prevent an imminent emergency condition or to restore the transmission grid to a secure state in the event of a system emergency. When an imminent threat has been confirmed, Forestry, Engineering, Transmission Field Services, Planning, the Transmission Dispatch Center, the System Control Center Operator, and other parties as required, will coordinate appropriate actions[13] to mitigate the threat until the vegetation threat is relieved.

When a vegetation issue is found by AEP personnel (non-Forestry), such as AEP line maintenance personnel, other experienced observers, or the general public, notification shall be sent either to the Transmission Dispatch Center, Forestry personnel, Distribution Dispatch Center, or Customer Solutions Center, as identified below. This is also summarized in an Imminent Threat Communication flowchart shown on page 23.

A. AEP Forestry Personnel

When AEP Transmission Forestry personnel (Forestry) identify a potential vegetation issue, for example, during aerial patrol, they should notify additional Forestry-designated personnel as needed. If Forestry personnel have confirmed a vegetation issue with clearances less than those in Column E of Table 3: Transmission Line Clearance Guidelines on page 19, they shall immediately[11] notify the Transmission Dispatch Center. The Transmission Dispatch Center shall capture the date and time in the Dispatcher Operating Log. After rectifying the vegetation issue, Forestry personnel shall follow up with documentation of the action taken, completing the Vegetation Imminent Threat Incident Report, and the Forestry Supervisor will route the report to management. Alternatively, if Forestry's professional evaluation reveals the vegetation condition is not an imminent threat, they should notify the Transmission Dispatch Center as needed.

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[12]NOPR RM-12-4-000, pg 50, #85 (10/18/2012) – NERC explains that the obligation to notify without intentional delay generally "can be understood to include an immediate (within 1 hour of observation) communication notwithstanding a safety issue to personnel, other immediate priority maintenance functions to ensure reliability or system stability, or communication equipment failures that precludes immediate communication."

[13]NERC Standard FAC-003-2 Technical Reference, pg 30 (9/30/2011) – Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit.

B. AEP Non-Forestry Personnel

1. Option 1: Notification to AEP Forestry Personnel (Preferred)

When AEP personnel (non-Forestry) find a vegetation issue, they may notify AEP Forestry of this issue. AEP Forestry personnel shall notify the Transmission Dispatch Center, as needed. If notified, the Transmission Dispatch Center captures the date and time in the Dispatcher Operating Log. AEP Forestry will investigate the potential threat as outlined in the procedures in Section A: AEP Forestry Personnel, page 20.

2. Option 2: Notification to Transmission Dispatch Center

When AEP personnel (non-Forestry) find a vegetation issue, they may notify the Transmission Dispatch Center of a potential vegetation issue, and the Transmission Dispatch Center shall notify AEP Forestry personnel and capture the date and time in the Dispatcher Operating Log. AEP Forestry will investigate the potential threat as outlined in the procedures in section A, AEP Forestry Personnel, page 20.

3. Option 3: Notification to Distribution Dispatch Center

When AEP personnel (non-Forestry) find a suspected vegetation issue, they may notify the AEP Distribution Dispatch Center. The Distribution Dispatch Center shall then notify the Transmission Dispatch Center. The Transmission Dispatch Center captures the date and time in the Dispatcher Operating Log and notifies AEP's Forestry personnel. The Transmission Dispatch Center will note this in the Dispatcher Operating Log. AEP Forestry will investigate the potential threat as outlined in the procedures in Section A, AEP Forestry Personnel, page 20.

4. Option 4: Notification to AEP Customer Solutions Center

When AEP personnel (non-Forestry) find a suspected vegetation issue, they may notify the AEP Customer Solutions Center, the same as non-AEP personnel in Section C, Non-AEP Personnel below.

C. Non-AEP Personnel

When non-AEP personnel find a suspected vegetation issue, the preferred notification is to an AEP Customer Solutions Center. Notifications can come from neighboring utilities, police, fire, other dispatch centers, or the general public. The AEP Customer Solutions Center immediately notifies the AEP Distribution Dispatch Center, who with the AEP Transmission Dispatch Center, determines if the line is transmission or distribution. The Transmission Dispatch Center captures the date and time in the Dispatcher Operating Log and notifies AEP's Forestry personnel. AEP Forestry will investigate the potential threat as outlined in the procedures in Section A: AEP Forestry Personnel, page 20.

The completed Forestry Vegetation Imminent Threat Incident Report contains the documentation of actions taken because of reported conditions where vegetation may imminently cause an outage. Reports are to be kept on file.

Vegetation Imminent Threat Incident Report

Rev. 7/02/2013

Forester: ____________________

TDC Case # ____________________

Part I – Basic Information

Line Name: ____________________

Circuit Name: ____________________

Right-of-Way

Structure #: ____________________ In [ ] Out [ ]

Operating Voltage: (i.e. 345kV) __________ yes or no / yes or no

Date and Time of Confirmation: ____________________

Location Information: (provide as much information as possible)

Property Owner: ____________________

County/Parrish: ____________________

State: ____________________

Part II – Vegetation Information (provide as much information as possible)

Species: ____________________

Estimated Height: ____________________

Estimated Age: ____________________

DBH: ____________________

Part III – Circuit Parameters at Time of Discovery/Notification

(at Time of Discovery/Notification)

Conductor Height __________ Time: __________

Circuit Electrical Load: ____________________

Estimated Ambient Air Temperature: ____________________

Estimated Wind Speed: ____________________

Weather Conditions: ____________________

Conductor Size and Type: ____________________

Percent Loading ____________________

Part IV – Action Taken:

Transmission Operations Reduced Loading:

	Operations Reduced Load	Returned to Normal Load
[ ] yes or no	[ ] date and time	[ ] date and time

	Operations-Out of Service	Returned / In-Service
[ ] yes or no	[ ] date and time	[ ] date and time

Circuit/Section Removed from Service:

	Removed from Service	Returned / In-Service
[ ] yes or no	[ ] date and time	[ ] date and time

Vegetation Condition Rectified:

[ ] yes or no	[ ] If yes, date and time

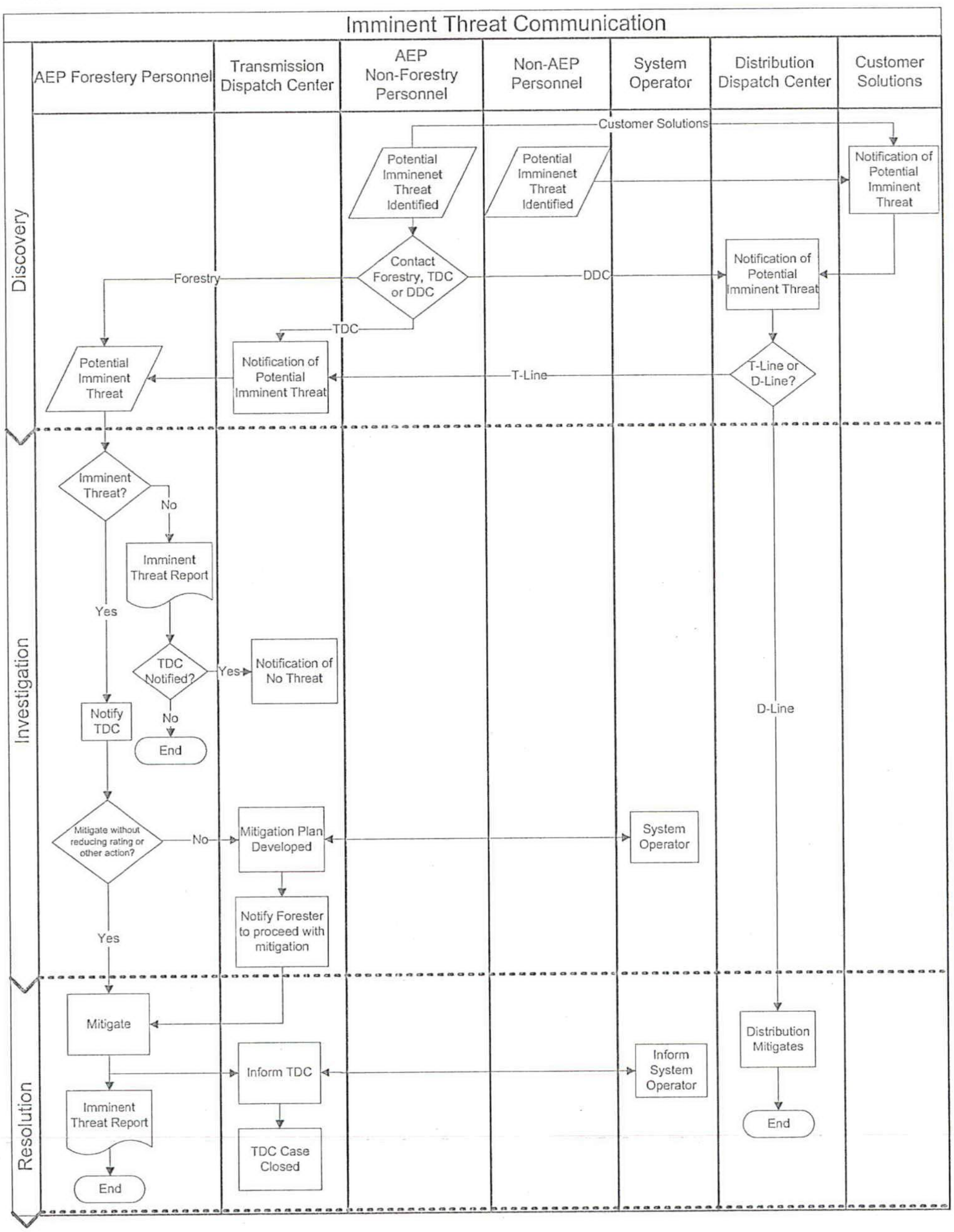
Comments:

[ ]

Describe the circumstances of the event.

____________________ Forestry Supervisor Approval   __________ date

Appendix C: Imminent Threat Communication



Appendix D: Subject Matter Experts

FAC-003-3 Requirement	Description	Preparer	SME	Reviewer
R1.–M1.	Manage vegetation to prevent encroachment into MVCD for IROL lines	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	J.E. Momme Director, Trans. Line Engineering 614-552-1180 jemomme@aep.com
R2.–M2.	Manage vegetation to prevent encroachment into MVCD for non- IROL lines	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	
R3.-M3.	Documented maintenance strategies	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	E. K. Engdahl, Staff Engineer 614-552-1676 ekengdahl@aep.com Jacqueline M. Rich Engineer II 614-552-1391 jmrich@aep.com Barrett Thomas Engineer I 918-599-2386 bathomas@aep.com R. J. Whitaker Engineer I 540-562-7054 rjwhitaker@aep.com	
R4.-M4.	Notify the control center holding switching authority of a confirmed vegetation condition	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	

FAC-003-3 Requirement	Description	Preparer	SME	Reviewer
R5.-M5.	Constrainted from performing vegetation work	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	
R6.-M6.	Complete inspections on 100% of applicable transmition lines	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	
R7.-M7.	Complete 100% of annual plan	Kevin Patton System Forestry Coordinator 614-716-1231 kbpatton@aep.com	Lynn Hayward Lead Engineer 614-883-7244 lehayward@aep.com	

Appendix E: TVMP Internal Mailing List[14]

Name/E-mail Group	Department	Title	Role
Smith, Scott N	Transmission Strat &Bus Dev	SVP Trans Grid Dev & Portfolio Svcs	A
Moore, Scott P	Trans Eng & Proj Svcs	VP Trans Eng & Proj Svcs	A
Kirkpatrick, Thomas L	Customer and Distr Services	VP Cust Svcs, Mktg & Dist Svcs	A
Crowder, J Calvin	Electric Transmission Texas	Exec. Dir. Elec. Trans TX	A
Sastry, Ram	Distribution Services	VP Infrastructure & Bus Cont	A
Recker, Daniel J	Transmission Engineering	Mng Dir Trans Projects Engrg	A
Momme, Jeffrey E	Transmission Line Engineering	Dir. Trans. Line Projects Engineering	A
Johnson, Paul B	Transmission Operations	Mng. Dir. Transmission Ops	A
Fecho, Thomas R	New Gen./Major Proj Oversight	Mgr-Gen & Elec Intrcnnctn Plnng	C
Parrish, T. David	Trans Line Standards	Mgr. Trans. Line Design Standards	C
Wagner, Robert C	Transmission Field Services	VP Trans Field Services	I
TRELCOMP	Transmission Reliability Compliance	Group Mailing List	I
Schaffer, Thomas O	Trans Line Engrg Right-of-Way	Mgr Trans Right of Way	I
Curiel III, Nicolas	Trans Line Engrg Right-of-Way	Supv Trans Right of Way	I
Jones, Paul R	Trans Line Engrg Right-of-Way	Supv Trans Right of Way	I
Merrifield, Ned O	Trans Line Engrg Right-of-Way	Supv Trans Right of Way	I
Nguyen, Thuy P	Trans Tech Svcs Wrk Plan	Mgr. Trans Work Planning	I
Rappach, James A	Generation NERC Compliance	Mgr-Regional Eng Svcs II	I
Fuller, Terry A	New Gen./Major Proj Oversight	Principal Engineer	I
Daniels, David	Generation NERC Compliance	Senior Engineer	I
Carlson, John P	ESH Management Systems	Mgr ESH Mngmnt System I	I
Liebrecht, John J	Trans Tech Svcs Wrk Plan Line	Supv Planning & Engineering II	I
Ordner, Lance	Trans Tech Svcs Wrk Plan Line	Engineer I	I
Cotant, Ronald D	Trans Tech Svcs Wrk Plan Line	Lead Engineer	I
York, Leo	Electric Transmission Texas	Mgr Transmission Bus Dev Sr	I
Macias, Michael M	Electric Transmission Texas	ETT Technical Project Lead Sr	I

[14] Role definitions: A—Accountable; C—Consult; I—Informed; R—Responsible; S—Support

Name/E-mail Group	Department	Title	Role
Schechter, John E	Trans Stat Prot Engrg Gahanna	Mgr Prot & Cntrl Asset Engrg	I
Garrett, James G	Trasm Reliability Compliance	Trans Relblty Complc Spec I	R
Sherry, Walter A	System Forestry	Mgr. Forestry Operations	R
T Forestry	Trans. Foresters and Forestry Management	Group Mailing List	R
Schnell, Edward G	Transmission Dispatch	Dir. Transmission Dispatching	R
Kunkel, Dennis K	Trans Dispatch Corpus Christi	Mgr. Transmission Dispatching	R
Milford, David L	Trans Dispatch Shreveport	Mgr. Transmission Dispatching	R
Moses, Clinton D	Trans Dispatch Columbus	Mgr. Transmission Dispatching	R
Guill, Darrell E	Trans Dispatch Roanoke	Mgr. Transmission Dispatching	R
Wagner, Billy W	Roanoke Dist Dispatch	Mgr. Distribution Dispatching	R
Ivinskas, Robert J	AEP Ohio Distr Dispatch	Mgr. Distribution Dispatching	R
Isaacson, David S	Ft Wayne Distrib Dispatch	Mgr. Distribution Dispatching	R
Apple, Dwayne L	PSO Distribution Dispatch	Mgr. Distribution Dispatching	R
Guin, Gary A	SWEPCO Distrib Dispatch	Mgr. Distribution Dispatching	R
Dunlap IV, Hauge	C Christi Distrib Dispatch	Mgr. Distribution Dispatching	R
Williams, Michael A	Kentucky Distribution Dispatch	Dispatch Supv. I	R
Patton, Kevin B	System Forestry	System Forestry Coord	R
Engdahl, Eric K	Trans Line Engrg Design Standards	Staff Engineer	R
Rich, Jacqueline M	Trans Line Eng Gahanna-Roanoke	Engineer II	R
Thomas, Barret A	Trans Line Engrg Tulsa Group	Engineer I	R
Whitaker, Robert	Trans Line Eng Gahanna-Roanoke	Engineer I	R
Hayward, Lynn E	Transmission Line Engrg	Lead Engineer	R
Krause, Stan A	Trans Line Engrg Tulsa Group	Mgr. Trans. Line Engineering	S
Grawe, Rob	Trans Line Eng Gahanna	Mgr. Trans. Line Engineering	S
Bledsoe, James K.	Trans Line Eng Roanoke	Mgr. Trans. Line Engineering	S
TLPE All	Transmission Line Project Engineering	Group Mailing List	S
TCI PM ALL	Transmission Project Mgt. &	Group Mailing List	S

Name/E-mail Group	Department	Title	Role
	Control		
Hostetler, Timothy A	Transmission Operations Engineering	Mgr. Operations Engineering	S
Sauriol, Dennis R	Transmission Real Time Operations	Mgr. Trans Ops. Reliability	S
Matthews, Charles D	Transmission Field Services	Mng. Dir. Transmission West	S
Rogier, Daniel J	Transmission Field Services	Mng. Dir. Transmission East	S
Boezio, Daniel R	Transmission Field Services	Dir Trans Region Tech Support	S
Cook, James K	Trans Field Construction East	Dir Trans Region Construction	S
McCord, Natalie J	Trans Field Construction West	Dir Trans Region Construction	S
Workman, Mark A	Trans Construction Mgmt	Mng Dir Trans Constr Mgmt	S
Colvin, Kenneth A	Trans Const Mgmt – Gahana	Mgr – Trans Construction II	S
Galyean, Rue F	Trans Construction Mgmt – Tulsa	Mgr – Trans Construction II	S
Emberger, Joseph H	Trans Const Mgmt – Gahana	Mgr – Trans Construction II	S

Kentucky Power Company

REQUEST

State the vegetation management plan and practices for the 166 miles of 46-kV electric facilities. Identify in the response any vegetation management practice for these facilities that differs from vegetation management practices for transmission facilities operating at or above 69 kV. Provide all documentation supporting the response.

RESPONSE

Please see the Company's response to KPSC 1-7.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Are there any points of service or other electric service arrangements that directly utilize electricity for the 34.5-kV or 46-kV electric facilities? If so, identify each point of service or other electric service arrangement.

RESPONSE

Please see KPSC 1-9 Attachment 1. Confidential treatment is being sought for portions of Attachment 1.

WITNESS: Everett G Phillips

REDACTED

KPSC'S FIRST DATA REQUEST NO. 9 CASE NO. 2014-00479	
COMPANY	**TRANSMISSION LINE**
[redacted]	Cedar Creek-Elwood 46 kV
	Cedar Creek-Elwood 46 kV
	Beaver Creek-McKinney 46 kV
	Armco-Bellefonte 34.5 kV

Kentucky Power Company

REQUEST

Refer to the record in Case No. 2006-00494.[1] At page 3 of the Direct Testimony and Exhibits of Everett G. Philips, filed with the Commission on April 13, 2007, Mr. Phillips states the following: "Our transmission system includes 1,235 miles of transmission lines in Kentucky with voltages ranging up to 765 kV. Our distribution system includes more than 9,636 miles of lower voltage lines on 205,915 company owned poles." Answer the following questions.

a. What portion of the 166 miles of 46-kV electric facilities were included as part of the 1,235 miles of transmission lines in Kentucky identified in Mr. Phillips' testimony in Case No. 2006-00494?

b. What portion of the 166 miles of 46-kV electric facilities were included as part of the more than 9,636 miles of lower-voltage lines?

c. What portion of the approximate ten miles of 34.5-kV electric facilities were included as part of the 1,235 miles of transmission lines in Kentucky identified in Mr. Phillips' testimony in Case No. 2006-00494?

d. What portion of the approximate ten miles of 34.5-kV electric facilities were included as part of the more than 9,636 miles of lower-voltage lines?

[1] Case No. 2006-00494, An Investigation of the Reliability Measures of Kentucky's Jurisdictional Electric Distribution Utilities and Certain Reliability Maintenance Practices (Ky. PSC Oct. 26, 2007).

RESPONSE

a. All of the 166 circuit miles of 46 kV were included in the 1,235 transmission circuit mile total.

b. None of the 46 kV circuit miles were included in the 9,636 distribution ("lower voltage") circuit mile total.

c. All of the circuit miles of 34.5 kV lines that function as transmission were included in the 1,235 transmission circuit mile total.

d. None of the circuit miles of 34.5 kV lines that function as transmission were included in the 9,636 distribution circuit mile total.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the record in PSC Case No. 2006-00494. At page 4 of the Direct Testimony and Exhibits of Everett G. Phillips, Mr. Phillips discusses ongoing "Distribution Asset Management Programs" and "Transmission Asset Management Programs." Answer the following questions.

a. What portion of the 166 miles of 46-kV electric facilities are included as part of a Distribution Asset Management Program? Provide all documentation supporting the response.

b. What portion of the 166 miles of 46-kV electric facilities are included as part of a Transmission Asset Management Program? Provide all documentation supporting the response.

c. What portion of the approximate ten miles of 34.5-kV electric facilities are included as part of a Distribution Asset Management Program? Provide all documentation supporting the response.

d. What portion of the approximate ten miles of 34.5-kV electric facilities are included as part of a Transmission Asset Management Program? Provide all documentation supporting the response.

RESPONSE

a. None of the 46 kV transmission electric facilities are included as part of a Distribution Asset Management Program.

b. All of the 46 kV transmission electric facilities are included as part of a Transmission Asset Management Program.

c. None of the 34.5 kV lines functioning as transmission electric facilities (corrected to approximately two miles) are included as part of a Distribution Asset Management Program.

d. All of the 34.5 kV lines functioning as transmission electric facilities are included as part of a Transmission Asset Management Program.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Identify the portion of the 166 miles of 46-kV pole miles that Kentucky Power includes in determining any allocation factors relating to maintenance of transmission right-of-way.

RESPONSE

All of the 46 kV transmission pole miles for Kentucky Power are included in determining the Pole Mile Allocation factor relating to maintenance of transmission rights-of-way.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Identify the portion of the approximate ten miles of 34.5-kV pole miles that Kentucky Power includes in determining any allocation factors relating to maintenance of transmission right of way.

RESPONSE

All of the 34.5 kV transmission pole miles for Kentucky Power are included in determining the Pole Mile Allocation factor relating to maintenance of transmission rights-of-way.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Indicate the functional class of property ("transmission" or "distribution") that Kentucky Power utilizes for recording the 166 miles of 46-kV electric facilities as property, plant, and equipment. Provide in the response the account number(s) in Kentucky Power's Chart of Accounts for these electric facilities

RESPONSE

The 166 miles of 46-kv electric facilities are classified as transmission property. The transmission line property less than 69-kv is classified as a group in Kentucky Power's property records labeled "Sub-Transmission Lines <=69KV-Kentucky". Depreciable overhead line type investment in that category (excluding land or land rights) includes the following property accounts:

354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductor & Devices

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Indicate the functional class of property ("transmission" or "distribution") that Kentucky Power uses for recording the approximate ten miles of 34.5-kV electric facilities as property, plant, and equipment. Provide in the response the account number(s) in Kentucky Power's Chart of Accounts for these electric facilities.

RESPONSE

The approximate 2 miles of 34.5-kv electric facilities functioning as transmission are classified as transmission property. The transmission line property less than 69-kv is classified as a group in Kentucky Power's property records labeled "Sub-Transmission Lines <=69KV-Kentucky". Depreciable overhead line type investment in that category (excluding land or land rights) includes the following property accounts:

354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductor & Devices

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Identify the depreciation practices for the 166 miles of 46-kV electric facilities. Provide in the response the deprecation rate(s) for the facilities

RESPONSE

Kentucky Power depreciation is calculated on a straight line basis using a group plan where depreciation expense is accrued upon the original cost of property included in each depreciable plant account. The depreciation practices used for the 166 miles of 46-kv electric facilities and for all investment are fully described in Attachment 1 to this response.

The Depreciation Study Report excerpt was filed as Exhibit DAD-2 in Case No. 2014-00396 by Company witness Davis. Both existing and proposed depreciation rates by plant account are included in column 4 and column 6 on page 22 of the attachment.

WITNESS: John A Rogness

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT

DECEMBER 31, 2013

DEPRECIATION STUDY REPORT

Table of Contents

I. INTRODUCTION

This report presents the results of a depreciation study of Kentucky Power Company's (KPCo) depreciable electric utility plant in service at December 31, 2013. The study was prepared by David A. Davis, Manager – Property Accounting Policy and Research at American Electric Power Service Corporation (AEPSC). The purpose of the depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts that comprise the functional groups for which KPCo computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in my Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> "Service value means the difference between original cost and the

net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Schedule I of this report shows the recommended depreciation accrual rates by primary plant accounts and composited to functional plant classifications. Schedule II compares depreciation expense using rates approved by the Commission and rates recommended by the depreciation study. Schedule III shows a comparison of the current mortality characteristics that were used to compute the recommended depreciation rates and the mortality characteristics used to determine the existing depreciation rates and accruals for Transmission, Distribution and General Plant Functions. A comparison of KPCo's current functional group composite depreciation rates and accruals to recommended functional group rates and accruals based on December 31, 2013 depreciable plant balances follows:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2013

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production (1)	3.80%	54,851,796	3.36%	48,418,617	(6,433,179)
Transmission	1.71%	8,478,288	2.66%	13,169,805	4,691,517
Distribution	3.52%	24,312,736	4.48%	30,971,933	6,659,197
General	2.54%	858,462	4.42%	1,492,241	633,779
Total Depreciable Plant	3.32%	88,501,282	3.50%	94,052,596	5,551,314

Note: (1) Includes Big Sandy and Mitchell plants. The Company is not recommending a change in depreciation rates for Big Sandy Plant due to the planned retirement of Unit 2 in 2015 and the coal related portions of Unit 1 in 2016.

Based on Total Company Depreciable Plant In-Service as of December 31, 2013, I am recommending an increase in depreciation rates that result in an increase in annual depreciation expense of $5,551,314. The depreciation rate changes are necessary because of changes in average service lives and net salvage estimates used to calculate KPCo's recommended depreciation rates that takes into account the December 31, 2013 transfer of a 50% undivided interest in the Mitchell generating station from AEP affiliate Ohio Power Company as approved by the Kentucky Public Service Commission (or Commission) in Case No. 2012-00578. KPCo's current approved depreciation rates with the exception of Mitchell Plant rates are based on a 1991 settlement agreement in Case No. 91-066 and were made effective on April 1, 1991. The Stipulation and Settlement Agreement in Case No. 2012-00578 ordered Kentucky Power to use the current Ohio Power Company depreciation rates for Mitchell Plant until such rates are changed in a base rate case.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Annual Depreciation Rates Using the Average Remaining Life Method

KPCo's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Life Span Analysis

The life span analysis was employed for Mitchell Plant. The life-span method of analysis is particularly suited to specific location property, such as generating plants, where all of the surviving investments are likely to be retired in total at a future date. The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those retirements that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. The age of Mitchell Plant's surviving investments at December 31, 2013 was obtained from the accounting records of affiliate Ohio Power Company (OPCo). American Electric Power Service Corporation (AEPSC) provided the retirement date used in the life-span analysis for Mitchell Plant.

The Company is not recommending any revision to Big Sandy Plant's depreciation rates in this filing since Unit 2 is planned for retirement at the end of May 2015 and the coal related portions of Unit 1 are planned for retirement in April 2016. KPCo expects to repower Big Sandy Unit 1 to use natural gas in 2016.

The order in the Mitchell transfer Case No. 2012-00578 allows Kentucky Power to recover the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site related retirement costs that will not continue in use. New depreciation rates will be required for Big Sandy Unit 1 after it is repowered to use natural gas in 2016.

Steam Production Plant

At December 31st, 2013, KPCo's depreciable investment in Steam

Production Plant includes the Big Sandy Generating plant and a 50% undivided interest in Mitchell Generation Plant. The Big Sandy plant is located highway 23 near Louisa, Kentucky and includes two generating units. The Mitchell Plant is located on the Ohio River near Moundsville, West Virginia and also consists of two generating units. All generating units at the Big Sandy and Mitchell plants are currently coal fired.

The generating units and their capacities are as follows (also shown on Schedule IV – Estimated Generation Plant Retirement Dates):

Plant	Unit	Rating	Commercial Operating Date
Big Sandy	1	260 MW	1963
Big Sandy	2	800 MW	1969
Mitchell	1	770 MW	1971
Mitchell	2	790 MW	1971

AEPSC evaluated each of the generating units and determined the following retirement dates for the units:

Plant	Unit	Retirement Date
Big Sandy	2	2015
Big Sandy	1	2016 coal related portion
Big Sandy	1	2031 repowered to use natural gas
Mitchell Plant	1,2	2040

Since KPCo's last depreciation study (property investment dated December 31, 2008), AEP has reevaluated the expected retirement dates for its generation plant including Big Sandy Units 1-2. The reevaluation for these two Big Sandy units indicated that their current estimated retirement dates should be 2015 for Big Sandy Unit 2, 2016 for the coal related portion of Big Sandy Unit 1 and 2031 for Big Sandy Unit 1 after it is repowered to use natural gas. AEP previously estimated individual unit retirement dates of 2023 for Unit 1 and 2029 for Unit 2. According to AEP, the earlier Big Sandy Unit 2 and the coal related portion of Unit 1 retirement dates are because it is not economically feasible to equip the units with necessary environmental controls, not because they have reached the end of their service lives.

Current plans are for the Mitchell Plant to operate for a total life of 69 years or until 2040.

Actuarial Analysis – Transmission, Distribution and General Plant

This method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates the retirements during each age interval to the exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending this stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

The Actuarial Method of Life Analysis was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment
390.0 General Structures & Improvements

The result of the actuarial analysis for the above accounts is detailed in the depreciation study work papers.

Simulated Plant Record Analysis – Transmission and Distribution Plant

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for a different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the "best fit" based on criteria selected by the user.

The results of my analysis using the Balance Method is shown in the depreciation study work papers. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the the Balances Method where a lower value for the Index of Variation indicates better agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures
355.0 Transmission Poles & Fixtures
356.0 Transmission Overhead Conductor & Devices
364.0 Distribution Poles, Towers & Fixtures
365.0 Distribution OH Conductor & Devices
366.0 Distribution Underground Conduit
367.0 Distribution Underground Conductor & Devices
368.0 Distribution Line Transformers
369.0 Distribution Services
370.0 Distribution Meters

371.0 Installation on Customers Premises

373.0 Street Lighting & Signal Systems

Vintage Year Accounting – General Equipment

In 1998, the Company began using a vintage year accounting method for general plant accounts 391 to 398 in accordance with Federal Energy Regulatory Commission Accounting Release Number 15 (AR-15). This accounting method requires the amortization of vintage groups of property over their useful lives. AR-15 also requires that property be retired when it meets its average service life.

As a result, my recommendation for these accounts is that the current useful life approved by the Commission be retained and used to continue amortization of the account balances.

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial and SPR Methods was primarily based on the results of the mortality analyses of past retirement history.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of the plant's experienced functional interim retirement, salvage and removal history for the period 2001-2013. No interim retirements were estimated for Big Sandy Plant in this depreciation study since Unit 2 is estimated to retire in 2015, the coal related portions of Unit 1 are estimated to retire in 2016 and the repowered Unit 1 (to use natural gas) is expected to retire in 2031.

While a standard type of analysis was used by the depreciation study to determine the net salvage characteristics applicable to interim retirements for the plants, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to Big Sandy and Mitchell plants, the Company contracted with Sargent & Lundy (S&L) to prepare conceptual demolition cost estimates. The S&L cost estimates to demolish the plants are based on current (2013) price levels which were inflated to retirement dates in the depreciation study. These estimates were incorporated into the calculation of a net salvage ratio for Steam Production Plant. S&L's demolition costs do not include Asset Retirement Obligation (ARO) amounts associated with the removal of asbestos or any cost associated with the final disposition of Big Sandy or Mitchell Plant landfills and ash ponds. The costs to remove asbestos and cover ash ponds are included separately in the cost of service through the accounting for asset retirement obligations.

2. <u>Net Salvage – Transmission, Distribution and General Plant</u>

The net salvage percentages used in this report for Transmission, Distribution and General Plant are expressed as percent of original cost and are based on the Company's experience combined with the judgment of the analyst. KPCo maintains salvage and removal costs in its depreciation ledger at the functional plant level, rather than by primary plant accounts. To determine gross salvage, gross removal and net salvage percentages for individual plant accounts, original cost retirements, salvage and removal were taken from the Company's account history in its PowerPlant software which detailed these amounts by account for the period 2000 to 2013. Gross salvage and cost of removal percentages were calculated using the data from this fourteen year time period for each account. The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios (1 minus the net salvage percentage) and appear in Column IV on Schedule I and were used to determine the total amount to be recovered through depreciation. The same net salvage was also reflected in the determination of the calculated depreciation requirement, which was used to allocate accumulated depreciation at the functional group to the accounts comprising each group.

5. Net Salvage – Ratios

The net salvage ratios shown on Schedule I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. CALCULATION OF DEPRECIATION REQUIREMENT AT DECEMBER 31, 2013

The accumulated depreciation by functional group was allocated to individual plant accounts based on the calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount recommended in this study.

V. STUDY RESULTS

Production, Transmission, Distribution and General plant results are discussed below. In addition, Transmission, Distribution and General Plant average service life, retirement dispersion pattern and net salvage percentages used to calculate each primary plant account depreciation rate are shown on Schedule III where the mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow trends shown by historical retirement experience. Gross salvage and gross cost of removal percentages were largely based on the history of each account for the period 2000-2013.

Steam Production Plant

Depreciation rates for Mitchell Plant were calculated by plant account with the expectation that the total cost including net salvage would be recovered by 2040 which is the estimated retirement date for Mitchell Plant. New depreciation rates for Big Sandy Plant were not recommended by the depreciation study. The comparison of steam production depreciation accruals on Schedule II using the currently approved depreciation rates and the study depreciation rates includes

Mitchell Plant. The original cost and accumulated depreciation amounts used for Mitchell Plant are 50% of the plant's original cost and accumulated depreciation on KPCo's books at December 31, 2013.

The decrease in steam production depreciation expense due to a change in depreciation rates was primarily due to the longer life estimate for Mitchell Plant in this proceeding (2040 retirement date) versus a previously estimated 2031 retirement date. The depreciation study doesn't recommend any changes to the Big Sandy Plant's depreciation rates.

Terminal demolition costs are included in the steam production depreciation rates. The estimates of demolition costs were developed by Sargent & Lundy. S&L estimated demolition cost in 2013 dollars for Big Sandy Plant and Mitchell Plant (KPCo's 50% share) was $28,831,786 and $21,185,697, respectively.

Transmission Plant

The depreciation rates for Transmission plant increased from 1.71% to 2.66% due to increases in the net salvage ratio for five accounts (accounts 352, 353, 354, 355 and 356) and decreases in the average service life for two accounts (accounts 354, and 355). The increase was partially offset by an increase in the average service life for account 352.

Distribution Plant

The depreciation rates for Distribution plant increased from 3.52% to 4.48% due to increases in the net salvage ratio for nine accounts (accounts 361, 362, 364, 365, 367, 368, 369, 371 and 373) and a decrease in the average service life for one account (account 370). The increase was partially offset by a decrease in the net salvage ratio for account 370 and by increases in the average service life for five accounts (accounts 361, 362, 366, 369 and 373).

General Plant

The depreciation rates for General plant increased from 2.54% to 4.42% due to increases in the net salvage ratio for three accounts (accounts 391, 394 and 398) and a reduction in the average service life for account 390. The increase was partially offset by a decrease in the net salvage ratio for account 397.

SCHEDULE I – EXPLANATION OF COLUMN HEADINGS

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2013
Column IV	-	Net Salvage Ratio.
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement.
Column VII	-	Allocated Accumulated Depreciation – accumulated depreciation (book reserve) spread to each account on the basis of the Calculated Depreciation Requirement shown in Column VI.
Column VIII	-	Remaining to be Recovered (Column V - Column VII).
Column IX	-	Average Remaining Life.
Column X	-	Recommended Annual Accrual Amount.
Column XI	-	Recommended Annual Accrual Percent or Depreciation Rate (Column X/Column III).

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
	STEAM PRODUCTION PLANT									
	Big Sandy Plant (1)									
311	Structures & Improvements	43,291,665	(1)	(1)	(1)	30,726,379	(1)	(1)	1,636,425	3.78%
312	Boiler Plant Equipment	362,456,070	(1)	(1)	(1)	177,325,748	(1)	(1)	13,700,839	3.78%
312	Boiler Plant Equip SCR Catalyst (2)	8,147,622	(1)	(1)	(1)	5,742,300	(1)	(1)	389,456	4.78%
314	Turbogenerator Units	109,522,949	(1)	(1)	(1)	61,149,688	(1)	(1)	4,139,967	3.78%
315	Accessory Electrical Equip.	16,513,202	(1)	(1)	(1)	12,896,303	(1)	(1)	624,199	3.78%
316	Misc. Power Plant Equip.	8,709,178	(1)	(1)	(1)	5,351,493	(1)	(1)	329,207	3.78%
	Total	548,640,686				293,191,911			20,820,093	3.79%
	Mitchell Plant (3)									
311	Structures & Improvements	42,000,197	1.07	44,940,211	18,282,178	16,183,402	28,756,809	25.01	1,149,812	2.74%
312	Boiler Plant Equipment	765,644,984	1.07	819,240,133	245,324,500	238,518,432	580,721,701	24.25	23,947,287	3.13%
312	Boiler Plant Equip SCR Catalyst (2)	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.07	57,026,396	29,106,660	33,613,523	23,412,873	23.84	982,084	1.84%
315	Accessory Electrical Equip.	17,080,672	1.07	18,276,319	9,466,086	11,043,285	7,233,034	25.81	280,242	1.64%
316	Misc. Power Plant Equip.	7,693,412	1.07	8,231,951	3,289,590	3,072,520	5,159,431	23.96	215,335	2.80%
	Total	893,905,077	1.07	955,905,125	309,492,408	304,809,655	651,095,470	23.59	27,598,524	3.09%
	Total Steam Prod. Plant	**1,442,545,763**	**0.66**	**955,905,125**	**309,492,408**	**598,001,566**	**651,095,470**	**13.45**	**48,418,617**	**3.36%**
	TRANSMISSION PLANT									
350.1	Land Rights	26,456,147	1.00	26,456,147	8,498,622	7,016,166	19,439,981	50.91	381,850	1.44%
352	Structures & Improvements	6,636,668	1.10	7,300,335	3,172,075	2,618,754	4,681,581	33.93	137,978	2.08%
353	Station Equipment	170,843,671	1.03	175,968,981	34,476,675	28,462,741	147,506,240	40.20	3,669,309	2.15%
354	Towers & Fixtures	94,517,543	1.10	103,969,297	56,679,229	46,792,396	57,176,901	23.20	2,464,522	2.61%
355	Poles & Fixtures	74,696,720	1.61	120,261,719	28,658,583	23,659,527	96,602,192	32.75	2,949,685	3.95%
356	OH Conductor & Devices	122,537,908	1.27	155,623,143	70,585,347	58,272,803	97,350,340	27.32	3,563,336	2.91%
357	Undergrnd Conduit	11,590	1.00	11,590	4,345	3,587	8,003	23.13	346	2.99%
358	Undergrnd Conductor	106,066	1.00	106,066	49,568	40,922	65,144	23.44	2,779	2.62%
	Total Transmission Plant	495,806,313	1.19	589,697,279	202,124,444	166,866,896	422,830,383	32.11	13,169,805	2.66%
	DISTRIBUTION PLANT									
360.1	Land Rights	5,343,520	1.00	5,343,520	1,411,791	1,371,633	3,971,887	55.18	71,981	1.35%
361	Structures & Improvements	4,372,006	1.12	4,896,647	1,354,850	1,316,312	3,580,335	50.63	70,716	1.62%
362	Station Equipment	83,664,562	1.07	89,521,081	18,549,279	18,021,648	71,499,433	26.16	2,733,159	3.27%
364	Poles, Towers, & Fixtures	180,551,331	1.30	234,716,730	68,606,654	66,655,150	168,061,580	19.82	8,479,394	4.70%
365	OH Conductor & Devices	179,538,721	0.94	168,766,398	33,083,601	32,142,543	136,623,855	20.90	6,537,027	3.64%
366	Underground Conduit	6,377,091	1.00	6,377,091	1,464,955	1,423,285	4,953,806	34.66	142,926	2.24%
367	Underground Conductor	9,812,956	1.13	11,088,640	1,655,544	1,608,452	9,480,188	37.43	253,278	2.58%
368	Line Transformers	119,012,919	1.01	120,203,048	28,150,578	27,349,840	92,853,208	19.15	4,848,731	4.07%
369	Services	53,900,363	1.38	74,382,501	17,054,558	16,569,444	57,813,057	15.41	3,751,658	6.96%
370	Meters	24,723,287	0.97	23,981,588	10,273,269	9,981,048	14,000,540	9.72	1,440,385	5.83%
371	Installations on Custs. Prem.	20,056,550	1.32	26,474,646	7,344,863	7,135,939	19,338,707	7.95	2,432,542	12.13%
373	Street Lighting & Signal Sys.	3,349,341	1.24	4,153,183	1,231,600	1,196,567	2,956,616	14.07	210,136	6.27%
	Total Distribution Plant	690,702,647	1.11	769,905,074	190,181,542	184,771,861	585,133,213	18.89	30,971,931	4.48%

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
GENERAL PLANT										
389.1	Land Rights	37,384	1.00	37,384	11,898	6,909	30,475	51.13	596	1.59%
390	Structures & Improvements	19,811,669	1.00	19,811,669	9,535,669	5,537,254	14,274,415	18.15	786,469	3.97%
391	Office Furniture & Equipment	1,683,333	1.00	1,683,333	377,310	219,100	1,464,233	27.15	53,931	3.20%
392	Transportation Equipment	14,768	1.00	14,768	1,742	1,012	13,756	26.46	520	3.52%
393	Stores Equipment	164,548	1.00	164,548	60,496	35,129	129,419	18.97	6,822	4.15%
394	Tools Shop & Garage Equip.	3,553,696	1.09	3,873,529	1,042,908	605,604	3,267,925	21.92	149,084	4.20%
395	Laboratory Equipment	141,765	1.00	141,765	89,929	52,221	89,544	10.97	8,163	5.76%
396	Power Operated Equipment	5,931	1.00	5,931	2,728	1,584	4,347	13.50	322	5.43%
397	Communication Equipment	7,318,955	0.97	7,099,386	2,872,871	1,668,243	5,431,143	13.10	414,591	5.66%
398	Miscellaneous Equipment	1,065,616	1.03	1,097,584	464,407	269,676	827,908	11.54	71,743	6.73%
	Total General Plant	33,797,665	1.00	33,929,897	14,459,958	8,396,732	25,533,165	17.11	1,492,241	4.42%
	Total Depreciable Plant	2,662,852,388		2,349,437,375	716,258,352	958,037,055	1,684,592,231		94,052,594	3.53%

N/A = Not Applicable

Notes:

(1) The Company plans to retire Big Sandy Unit 2 at the end of May 2015 and the coal related portions of Unit 1 in 2016. Since the Commission authorized (Case No. 2012-00578) the Company to recover the coal-related portion of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and any other site related retirement costs, this depreciation recommends that the existing approved depreciation rates for Big Sandy Plant be retained until a future proceeding that includes the remaining portion of Big Sandy Unit 1 and the cost to re-power this unit to use natural gas.

(2) An annualized depreciation rate for Big Sandy Plant's SCR Catalyst was calculated using currently approved rates and included in the above analysis. A separate depreciation rate was calculated for Mitchell Plant's SCR Catalyst using AEP Air Emmissions Control estimated average life for the catalyst.

(3) Mitchell Plant cost at December 31, 2013. At December 31, 2013 the Mitchell Plant was jointly owned 50% by Kentucky Power Company and 50% by AEP Generating Resources and therefore the cost shown above is 50% of the total Mitchell Plant depreciable plant in service. The Mitchell Plant cost includes 50% of the investment in the gypsum plant underloader located at the Mountaineer Generating Station.

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
STEAM PRODUCTION PLANT							
BIG SANDY PLANT (a)							
311	Structures & Improvements	43,291,665	3.78%	1,636,425	3.78%	1,636,425	0
312	Boiler Plant Equipment	362,456,070	3.78%	13,700,839	3.78%	13,700,839	0
312	Boiler Plant Equip SCR Catalyst	8,147,622	4.78%	389,456	4.78%	389,456	0
314	Turbogenerator Units	109,522,949	3.78%	4,139,967	3.78%	4,139,967	0
315	Accessory Electrical Equipment	16,513,202	3.78%	624,199	3.78%	624,199	0
316	Misc. Power Plant Equip.	8,709,178	3.78%	329,207	3.78%	329,207	0
	Total	548,640,686	3.79%	20,820,093	3.79%	20,820,093	0
MITCHELL PLANT - (b)							
311	Structures & Improvements	42,000,197	2.87%	1,205,406	2.74%	1,149,812	(55,594)
312	Boiler Plant Equipment	765,644,984	3.90%	29,860,154	3.13%	23,947,287	(5,912,867)
312	Boiler Plant Equip SCR Catalyst (c)	8,190,115	10.00%	819,012	12.50%	1,023,764	204,752
314	Turbogenerator Units	53,295,697	2.86%	1,524,257	1.84%	982,084	(542,173)
315	Accessory Electrical Equipment	17,080,672	2.39%	408,228	1.64%	280,242	(127,986)
316	Misc. Power Plant Equip.	7,693,412	2.79%	214,646	2.80%	215,335	689
	Total	893,905,077	3.81%	34,031,703	3.09%	27,598,524	(6,433,179)
	Total Steam Production Plant	**1,442,545,763**	**3.80%**	**54,851,796**	**3.36%**	**48,418,617**	**(6,433,179)**
TRANSMISSION PLANT							
350.1	Land Rights	26,456,147	1.71%	452,400	1.44%	381,850	(70,550)
352	Structures & Improvements	6,636,668	1.71%	113,487	2.08%	137,978	24,491
353	Station Equipment	170,843,671	1.71%	2,921,427	2.15%	3,669,309	747,882
354	Towers & Fixtures	94,517,543	1.71%	1,616,250	2.61%	2,464,522	848,272
355	Poles & Fixtures	74,696,720	1.71%	1,277,314	3.95%	2,949,685	1,672,371
356	OH Conductor & Devices	122,537,908	1.71%	2,095,398	2.91%	3,563,336	1,467,938
357	Underground Conduit	11,590	1.71%	198	2.99%	346	148
358	Underground Conductor & Devices	106,066	1.71%	1,814	2.62%	2,779	965
	Total Transmission Plant	**495,806,313**	**1.71%**	**8,478,288**	**2.66%**	**13,169,805**	**4,691,517**
DISTRIBUTION PLANT							
360.1	Land Rights	5,343,520	3.52%	188,092	1.35%	71,981	(116,111)
361	Structures & Improvements	4,372,006	3.52%	153,895	1.62%	70,716	(83,179)
362	Station Equipment	83,664,562	3.52%	2,944,993	3.27%	2,733,159	(211,834)
364	Poles, Towers, & Fixtures	180,551,331	3.52%	6,355,407	4.70%	8,479,394	2,123,987
365	Overhead Conductor & Devices	179,538,721	3.52%	6,319,763	3.64%	6,537,027	217,264
366	Underground Conduit	6,377,091	3.52%	224,474	2.24%	142,926	(81,548)
367	Underground Conductor	9,812,956	3.52%	345,416	2.58%	253,278	(92,138)
368	Line Transformers	119,012,919	3.52%	4,189,255	4.07%	4,848,731	659,476
369	Services	53,900,363	3.52%	1,897,293	6.96%	3,751,658	1,854,365
370	Meters	24,723,287	3.52%	870,260	5.83%	1,440,385	570,125
371	Installations on Custs. Prem.	20,056,550	3.52%	705,991	12.13%	2,432,542	1,726,551
373	Street Lighting & Signal Sys.	3,349,341	3.52%	117,897	6.27%	210,136	92,239
	Total Distribution Plant	**690,702,647**	**3.52%**	**24,312,736**	**4.48%**	**30,971,933**	**6,659,197**

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
GENERAL PLANT							
389.1	Land Rights	37,384	2.54%	950	1.59%	596	(354)
390	Structures & Improvements	19,811,669	2.54%	503,216	3.97%	786,469	283,253
391	Office Furniture & Equipment	1,683,333	2.54%	42,757	3.20%	53,931	11,174
392	Transportation Equipment	14,768	2.54%	375	3.52%	520	145
393	Stores Equipment	164,548	2.54%	4,180	4.15%	6,822	2,642
394	Tools Shop & Garage Equipment	3,553,696	2.54%	90,264	4.20%	149,084	58,820
395	Laboratory Equipment	141,765	2.54%	3,601	5.76%	8,163	4,562
396	Power Operated Equipment	5,931	2.54%	151	5.43%	322	171
397	Communication Equipment	7,318,955	2.54%	185,901	5.66%	414,591	228,690
398	Miscellaneous Equipment	1,065,616	2.54%	27,067	6.73%	71,743	44,676
	Total General Plant	33,797,665	2.54%	858,462	4.42%	1,492,241	633,779
	Total Depreciable Plant	2,662,852,388	3.32%	88,501,282	3.53%	94,052,596	5,551,314

Notes:

(a) The depreciation study recommends that the current approved depreciation rates for Big Sandy Plant remain in effect until the next base case which will reflect the retirement of Big Sandy Unit 2 in 2015, the coal related portions of Unit 1 in 2016 and the cost to re-power Unit 1 to burn natural gas. Therefore there is no change in depreciation expense due to a change in depreciation rates for Big Sandy Plant.

(b) The current approved rates for Mitchell Generating Plant are from AEP affiliated company, Ohio Power Company as per the Order in Case No. 2012-00578.

(c) The depreciation rate was revised for the SCR catalyst at Mitchell Generating Station using AEP Generation's estimated average life for the catalyst of 8 years.

KENTUCKY POWER COMPANY
SCHEDULE III - COMPARISON OF MORTALITY CHARACTERISTICS
DEPRECIATION STUDY AS OF DECEMBER 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Existing Rates (See note, below)					Current Study Rates				
	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor
TRANSMISSION PLANT										
350.1 Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
352.0 Structures & Improvements	55	S1.5	N/A	N/A	0%	60	S3.0	0%	10%	-10%
353.0 Station Equipment	50	R0.5	N/A	N/A	25%	50	L0.5	8%	11%	-3%
354.0 Towers & Fixtures	55	R4.0	N/A	N/A	0%	51	S6.0	3%	13%	-10%
355.0 Poles & Fixtures	45	R3.0	N/A	N/A	0%	43	L3.0	2%	63%	-61%
356.0 Overhead Conductor & Devices	50	R3.0	N/A	N/A	10%	50	S6.0	6%	33%	-27%
357.0 Underground Conduit	37	R2.0	N/A	N/A	0%	37	R2.0	0%	0%	0%
358.0 Underground Conductor and Devices	44	R1.0	N/A	N/A	0%	44	R1.0	0%	0%	0%
DISTRIBUTION PLANT										
360.1 Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
361.0 Structures & Improvements	65	L0.5	N/A	N/A	0%	70	R2.0	4%	16%	-12%
362.0 Station Equipment	25	L0.0	N/A	N/A	25%	33	R0.5	10%	17%	-7%
364.0 Poles, Towers, & Fixtures	28	L0.0	N/A	N/A	25%	28	R0.5	18%	48%	-30%
365.0 Overhead Conductor & Devices	26	R1.5	N/A	N/A	25%	26	L0.0	30%	24%	6%
366.0 Underground Conduit	37	R2.0	N/A	N/A	0%	45	R3.0	0%	0%	0%
367.0 Underground Conductor	44	R1.0	N/A	N/A	0%	44	R0.5	1%	14%	-13%
368.0 Line Transformers	25	R1.5	N/A	N/A	15%	25	L0.0	29%	30%	-1%
369.0 Services	18	R2.0	N/A	N/A	0%	20	L0.0	1%	39%	-38%
370.0 Meters	27	R0.5	N/A	N/A	0%	17	R4.0	22%	19%	3%
371.0 Installations on Custs. Prem.	11	L0.0	N/A	N/A	30%	11	L0.0	1%	33%	-32%
373.0 Street Lighting & Signal Sys.	15	L0.0	N/A	N/A	15%	20	L0.0	1%	25%	-24%
GENERAL PLANT										
389.1 Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
390.0 Structures & Improvements	45	L3.0	N/A	N/A	0%	35	L2.0	1%	1%	0%
391.0 Office Furniture & Equipment	35	R0.5	N/A	N/A	10%	35	SQ	0%	0%	0%
392.0 Transportation Equipment	30	R3.0	N/A	N/A	0%	30	SQ	0%	0%	0%
393.0 Stores Equipment	30	R1.0	N/A	N/A	0%	30	SQ	0%	0%	0%
394.0 Tools Shop & Garage Equipment	30	R0.5	N/A	N/A	0%	30	SQ	0%	9%	-9%
395.0 Laboratory Equipment	30	L5.0	N/A	N/A	0%	30	SQ	0%	0%	0%
396.0 Power Operated Equipment	N/A	N/A	N/A	N/A	N/A	25	SQ	0%	0%	0%
397.0 Communication Equipment	22	L3.0	N/A	N/A	0%	22	SQ	6%	3%	3%
398.0 Miscellaneous Equipment	20	S5.0	N/A	N/A	0%	20	SQ	0%	3%	-3%

Note: Kentucky Power Company's existing depreciation rates are from Case No. 91-066. No detail of Cost of Removal % and Salvage Factor % is available from the order from that Case.

Kentucky Power Company

REQUEST

Identify the depreciation practices for the approximate ten miles of 34.5-kV electric facilities. Provide in the response the depreciation rate(s) for the facilities.

RESPONSE

Please see the Company's response to KPSC 1-16 regarding KPCo's depreciation practices and depreciation rates. In an identical manner to the 166 miles of 46-kv electric facilities, the group plan and the straight line type depreciation method is used for the approximate two miles of 34.5-kv electric facilities.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Refer to the record in PSC Case No. 2006-00494. At page 14 of the Direct Testimony and Exhibits of Everett G. Phillips, filed with the Commission on April 13, 2007, Mr. Phillips describes Kentucky Power's "Transmission Vegetation Management Program" and makes the following statement: "KPCo performs aerial vegetation patrols of its entire transmission system once a year to assist in developing a vegetation management work plan. In addition, vegetation maintenance on transmission lines is performed on an ongoing basis, depending upon the rate of growth of the vegetation and the voltage of specific transmission lines rather than on a rigid cycle basis, which would schedule circuits for maintenance, based upon the time elapse since the last maintenance work was performed." Answer the following questions.

a. Identify the vegetation maintenance schedule Kentucky Power would utilize for the 166 miles of 46-kV electric facilities if the Commission were to grant Kentucky Power's request for a deviation. Provide in the response an explanation of whether Kentucky Power plans to synchronize its inspection of these facilities with its vegetation maintenance patrols.

b. Identify the vegetation maintenance schedule Kentucky Power would utilize for the approximate ten miles of 34.5-kV electric facilities If the Commission were to grant Kentucky Power's request for a deviation. Provide In the response an explanation of whether Kentucky Power plans to synchronize Its Inspection of these facilities with Its vegetation maintenance patrols.

c. Does Kentucky Power plan to utilize a "rigid cycle basis" for Inspecting Its 46-kV or 34.5-kV electric facilities If the Commission were to grant Kentucky Power's request for a deviation? If so, explain why. If not, Identify and explain the Inspection plan.

RESPONSE

a. Please see the response to KPSC 1-7. Kentucky Power does not use a fixed cycle based maintenance schedule. Using a performance-based annual plan approach for transmission rights-of-ways below 200 kV allows the Company to address the circuits with the greatest need of vegetation management. At the end of each year the following year's plan is developed based on year-end circuit performance. The annual vegetation management work plans are flexible and dynamic. Inputs to these work plans come from our visual inspections which are part of our annual assessment, historical reliability data, line inspections, customer density, circuit performance, weather, customer complaints and time elapsed since vegetation management was last performed.

b. The Company would adhere to the same maintenance process described in its response to KPSC 1-18a.

c. No. See the response to KPSC 1-18a.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the record In Case No. 2006-00494· At pages 14 and 15 of the Direct Testimony and Exhibits of Everett G. Phillips, filed with the Commission on April 13, 2007, Mr. Phillips discusses reliability. Has a Regional Reliability Council determined that all or any portions of the 46-kV or 34.5-kV electric facilities are "critical transmission lines of lower voltage," as that phrase Is used Mr. Phillips' testimony? Provide all documentation In support ofthe response.

RESPONSE

The Regional Reliability Council for Kentucky Power, Reliability First Corporation, has not designated any portion of the 46 kV or 34.5 kV electric facilities in KPCo as "critical transmission lines of lower voltage".

WITNESS: Everett G Phillips