COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power	)	
Company For A Certificate Of Public Convenience	)	
And Necessity To Perform Upgrade, Replacement,	)	Case No. 2019-00154
And Installation Work At Its Existing Substation	)	
Facilities In Perry And Leslie Counties, Kentucky	)	

DIRECT TESTIMONY OF

KAMRAN ALI

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Kamran Ali. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director of Transmission Planning. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (AEP) system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 8500 Smiths Mill Road, New Albany, Ohio 43054.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science – Electrical Engineering degree from the University of Alabama in Tuscaloosa, Alabama and a Master of Science –Electrical Engineering degree from Kansas State University in Manhattan, Kansas. I also received a Master of Business Administration degree from Ohio University in Athens, Ohio.

I started my career as an electrical engineer at SMC Electrical and joined AEP as a substation engineer in 2006. In 2007, I transferred to Transmission Planning, where I advanced through increasing levels of responsibility. In December 2018, I assumed the position of Managing Director of Transmission Planning.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF TRANSMISSION PLANNING?

A. My responsibilities include organizing and managing all activities related to assessing the adequacy of AEP's and its operating companies' transmission networks, including within the PJM Interconnection, LLC (PJM) Regional Transmission Organization (RTO) region, to meet customers' and system needs in a reliable, cost effective, and environmentally compatible manner.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have testified before the Public Utilities Commission of Ohio, the Maryland Public Service Commission, and the Pennsylvania Public Utility Commission, and I have submitted testimony before the Public Service Commission of Kentucky ("Commission"), the Indiana Utility Regulatory Commission, and the Michigan Public Service Commission on behalf of various other electric operating companies of the AEP system.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying in support of Kentucky Power's application for a certificate of public convenience and necessity to perform upgrade, replacement, and installation work in connection with facilities and equipment at Kentucky Power's existing Hazard 161/138/69 kV Substation ("Hazard Substation") and Wooton 161 kV Substation ("Wooton Substation") (the proposed work at the Hazard and Wooton substations collectively is designated as the "Project"). More specifically, my testimony supports the portions of the Application and related exhibits that pertain to the PJM process through which the

Company receives stakeholder input in the Regional and Sub-regional Transmission Expansion Plan (RTEP) and Transmission Expansion Advisory Committee (TEAC) meetings. I also describe the proposed work at the two substations, the need for the work, as well as provide an overview of **EXHIBIT 2** to the Application.

Q. BEFORE DESCRIBING THE PJM PROCESS, PLEASE DESCRIBE, AT A HIGH LEVEL, THE WORK FOR WHICH KENTUCKY POWER IS SEEKING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.

A. The Project consists of necessary upgrades and element replacement work at the Hazard and Wooton Substations. This work will bring the elements into conformity with current design and safety specifications. It will also replace failing and aging equipment and facilitate the installation and operation of the work that the Commission previously approved in Case No. 2017-00328.

The Hazard Substation elements include the following:

1. Replacement and relocation of the 161kV Circuit Breaker (M) and associated line relaying pointing towards Wooton.
2. Installation of a low side 138 kV circuit breaker and upgrade relaying on the new 161/138 kV transformer #3.
3. Installation of a new three phase 161/138 kV spare transformer.
4. Addition of circuit breakers and circuit switchers along with their associated ancillary equipment to separate dissimilar zones of protection existing within the station's current arrangement.
5. Installation of a 69 kV circuit breaker connecting 69 kV Bus #1 and Bus #2.
6. Mitigation of known safety concerns such as station platforms that do not

conform to current safety, clearance, or structural standards.

7. Replacement of several components that are approaching or have exceeded their projected operating lives, are no longer supported by their manufacturers or are suffering from corrosion, damage, leaks and other malfunctions.
8. Replacement of electromechanical and static relays, which are no longer supported by manufacturers, with the current standard microprocessor based relays and controls.

The Wooton Station elements include:

1. Installation of surge arrestors on the 161 kV box bay structure on the Hazard Line position.
2. Installation of telecommunication fiber equipment for remote monitoring and operation (via SCADA) of equipment.
3. Installation of two coupling capacitor voltage transformers (CCVTs) on Phase 2 and Phase 3 of the existing 161 kV bus to meet industry-accepted protection and control standards.

IV. <u>TRANSMISSION PLANNING AND EXPANSION</u>

Q. WHAT IS PJM?

A. FERC Order 2000 introduced the concept of an RTO or an Independent System Operator (ISO) whose purpose is to promote the regional administration of high-voltage transmission and ensure non-discriminatory access to transmission systems. PJM Interconnection is a FERC-approved RTO that coordinates and administers the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. The Commission approved Kentucky Power's transfer of functional operation of its transmission facilities to PJM by its Order dated May 19, 2004, in Case No. 2002-00475.[1] The AEP System–East Zone (AEP Zone), which includes Kentucky Power, integrated its operations with PJM and began participating in the PJM energy market on October 1, 2004.

Q. HOW DO PJM, AEP, AND KENTUCKY POWER COORDINATE PLANNING AND OPERATION OF KENTUCKY POWER'S TRANSMISSION SYSTEM?

A. Kentucky Power's transmission system is part of the AEP eastern transmission system, which consists of the transmission facilities of ten AEP operating or transmission companies including Kentucky Power, Appalachian Power Company, Ohio Power Company, Indiana Michigan Power Company, Wheeling Power Company, Kingsport Power Company, AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company. This expansive system allows the economical and reliable delivery of electric power for all AEP customers, including customers of Kentucky Power.

Planning and operation of the system is integrated through the coordinated efforts of the AEP Transmission Department ("AEP Transmission"), a business unit of AEPSC, and PJM. AEP Transmission works closely with neighboring utilities, other interconnected entities, and PJM to plan and operate the transmission grid. RTOs align the transmission planning and operating requirements set out in each RTO's protocols and operating criteria, as further defined through North American Electric Reliability Corporation (NERC) requirements. Kentucky Power has input into the RTO planning process through AEP Transmission.

[1] *In the Matter of: The Application Of Kentucky Power Company D/B/A American Electric Power For Approval, To The Extent Necessary, To Transfer Functional Control Of Transmission Facilities Located In Kentucky To PJM Interconnection , L.L.C. Pursuant To KRS 278.218.*

Q. PLEASE DESCRIBE THE PJM RTEP PROCESS.

A. The PJM RTEP process is a 24-month planning process that identifies reliability issues over a 15-year horizon. The 24-month planning process consists of overlapping 18-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria.

Q. WHAT TYPES OF PROJECTS RESULT FROM THE RTEP PROCESS?

A. Kentucky Power, through AEP Transmission, participates in the PJM planning process, which is guided by PJM, NERC, RFC, and AEP planning criteria. The process generally results in two categories of projects: Baseline and Supplemental. Each category is described in detail below.

The first project category is Baseline Upgrades. Using the aforementioned criteria, PJM and Kentucky Power, in conjunction with AEP, identify needs that must be addressed. Baseline projects include transmission expansions or enhancements that are required to achieve compliance with respect to PJM's system reliability, operational performance, or market efficiency criteria as determined by PJM's Office of the Interconnection, as well as projects that are needed to meet Transmission Owners' local transmission planning criteria.

The second project category is Supplemental Projects. Supplemental Projects include all projects that are not addressing minimum bright-line Transmission Planning criteria. These projects are needed to maintain the existing grid as designed, connect new customers to the grid, satisfy contractual and regulatory requirements, and to meet RTO and industry standards, as set forth in the PJM Operating Agreement. Examples of Supplemental upgrades include interconnection of new retail demand, modification to existing delivery points, replacing failed equipment, proactive replacement of deteriorating assets in poor condition prior to failure, modernization and hardening of the grid, improved operational efficiency and performance, and installation and expansion of supervisory control and data acquisition.

Q. WAS THE PJM TRANSMISSION PLANNING PROCESS FOR SUPPLEMENTAL PROJECTS REVISED RECENTLY?

A. Yes, PJM recently revised the transmission planning process for Supplemental Projects. In August 2016, FERC established Docket EL16-71 to evaluate the justness and reasonableness of the PJM OATT with respect to Supplemental Projects planning and procedures. On February 15, 2018, FERC found that the PJM OATT was inconsistent with FERC Order No. 890's principles of coordination and transparency. In response, the PJM Transmission Owners submitted a compliance filing on March 19, 2018 that proposed to:

- provide for separate stakeholder meetings to discuss:
    - models, criteria, and assumptions used to plan Supplemental Projects (Assumptions Meeting);
    - needs underlying Supplemental Projects (Needs Meeting); and
    - proposed solutions to meet those needs (Solutions Meeting).
- post criteria, assumptions, and models at least 20 calendar days prior to the Assumptions Meeting;
- post criteria violations and drivers at least 10 days in advance of the Needs Meeting;
- post potential solutions and alternatives identified by the PJM Transmission Owners or stakeholders at least 10 days in advance of the Solutions Meeting;

and

- submit comments at least 10 days before the Local Plan is integrated into the RTEP for PJM Transmission Owner review and consideration.

FERC has been very specific that the changes it required in Docket EL16-71 are prospective only.[2] Thus, Supplemental Projects reviewed prior to the effective date of the new process were and will continue to be subject to the rules applicable when they were reviewed. It is also important to understand that Supplemental Projects that the Company presents through the PJM stakeholder process are no different from the types of projects for which the Company previously sought, and the Commission previously granted, certificates of public convenience and necessity before Kentucky Power joined PJM.

Q. DOES KENTUCKY POWER FOLLOW SPECIFIC GUIDELINES TO DETERMINE THE NECESSITY OF SUPPLEMENTAL PROJECTS?

A. Yes. Kentucky Power follows an established and detailed protocol to evaluate and select Supplemental Projects that assures only projects that are needed are pursued. See **EXHIBIT KA-1**, AEP Guidelines for Transmission Owner Identified Needs.

The guidelines discuss the drivers or inputs that should be considered when evaluating transmission system needs. The guidelines ensure that all AEP-affiliated Transmission Owners are applying consistent criteria in their evaluations; Kentucky Power ultimately determines the mix of Supplemental Projects needed to maintain the reliability of its transmission grid within the AEP Zone.

Consistent with the AEP Guidelines for Transmission Owner Identified Needs, Kentucky Power considers safety risks or concerns, asset condition, abnormal operating

[2] *See, e.g., Monongahela Power Co.*, 162 FERC ¶ 61,129 at 58 (¶¶ 120 and 121).

conditions, reliability performance, RTO or ISO notices, stakeholder and customer input, state and federal standards or policies, including NERC transmission planning standards, and environmental impacts in identifying Supplemental Projects.

Q. WHAT DRIVERS OR INPUTS DOES KENTUCKY POWER CONSIDER IN IDENTIFYING SUPPLEMENTAL PROJECTS?

A. Consistent with the AEP Guidelines for Transmission Owner Identified Needs, the considerations include:

- Equipment Condition, Performance and Risk: These are investments made to ensure the safe and reliable operation of the transmission system. The decision to pursue such projects can be based on equipment performance, obsolescence and expected life concerns, equipment condition, reliability impact, maintenance costs, environmental impact and engineering recommendations.
- Operational Flexibility and Efficiency: These projects can optimize system configuration, lower equipment duty cycles, reduce the impact on and limit the exposure to customers for planned or forced outages and can facilitate improved restoration times. They also provide opportunities to bring the system up to current standards and design principles.
- Infrastructure Resilience: These projects can improve system ability to anticipate, absorb, adapt to and/or rapidly recover from disruptive natural or man-made events including severe weather, geo-magnetic disturbances and physical and cyber security challenges.
- Customer Service: These projects accommodate new, increasing or future load so that the system can reliably address customer needs.

- Other Drivers: Examples include industry recommendations, changes to standards and regulations, and state policy objectives.

Q. WHAT IS PJM'S ROLE IN REVIEWING SUPPLEMENTAL PROJECTS?

A. All projects affecting the topology of the grid (*i.e.*, projects that impact the modeled structure of the grid), whether baseline or supplemental, are subject to the stakeholder process within PJM. While PJM does not "approve" Supplemental Projects, these projects are submitted to PJM and reviewed with the TEAC or Sub-regional RTEP Committee – Western on a regular basis (typically monthly). All TEAC and Sub-regional RTEP Committee – Western meetings are open and any transmission stakeholder can attend and participate. Any stakeholder input regarding specific projects is vetted through this PJM committee meeting process. Supplemental Projects are subject to two rounds of review and detailed system needs and project information, including alternative solutions, are provided to stakeholders.

Q. IS THE DESIGNATION OF A PROJECT AS A BASELINE OR SUPPLEMENTAL PROJECT INDICATIVE OF WHETHER THE PROJECT IS NECESSARY, OR HOW NECESSARY IT IS?

A. No, it is not. The designation of a project as a Baseline or Supplemental Project is not indicative of the level of, or absence of, need for the project. Instead, the designations simply reflect that the project satisfies different planning requirements and parameters. The criteria for designation as a Supplemental or Baseline project are not mutually exclusive, and a single project sometimes can be justified under either.

Supplemental Projects are required for the reasons discussed on pages 6-7 of this testimony. Supplemental Projects improve or preserve a PJM Transmission Owner's ability to provide reliable service to its customers, consistent with its obligation to serve, and are grounded in good utility practice.

Q. DOES PJM FACTOR THE AGE OR CONDITION OF EQUIPMENT INTO ITS FORWARD LOOKING MODELS FOR SYSTEM RELIABILITY?

A. No, it does not. The forward-looking models that PJM and transmission owners employ to identify Baseline Projects assume the modeled system will perform as designed without regard to the age or actual condition of all the elements of the transmission system, including those elements constructed, upgraded, or maintained as non-baseline elements. This means that for modeling purposes, a substation with 75-year old components that are deteriorating is assumed to function with the same reliability as a five-year old substation with newer components.

Although PJM transmission planning treats load dropping as an acceptable means of mitigating potential system reliability criteria violations under certain scenarios, such a planning approach is contrary to Kentucky Power's obligation under KRS 278.030(3) to provide "adequate, efficient and reasonable service," including the safe and reliable delivery of electricity to its customers. In that regard, Baseline projects alone would be insufficient to satisfy Kentucky Power's obligation to provide safe and reliable service to its customers.

Q. IS ALL OF THE WORK ASSOCIATED WITH A TRANSMISSION PROJECT SUBMITTED TO PJM?

A. No. There are project elements that either do not change the transmission grid's topology, or that are implicit in the description of larger projects, that are not required to be submitted to PJM for explicit review. These project elements do not affect the transmission grid analysis within the framework of PJM's FERC-approved planning process. These project elements nevertheless are essential to the larger projects submitted to PJM.

For example, when a new breaker installation project is submitted to PJM, the breaker would likely be the only major piece of equipment listed in the submission. The PJM submission would not include a listing of elements such as Coupling Capacitor Voltage Transformers (CCVTs) and relaying required for the breaker to function properly. CCVTs are utilized for real time voltage sensing on the grid. Relays receive information from CCVTs and other instrument transformers and determine the proper course of action for the equipment to which they are tied. Without the relays and CCVTs, the breaker would not know when or how to operate.

Q. IS THERE ALSO A PROCESS FOR REVIEWING TRANSMISSION PROJECTS AT FERC?

A. Yes. In addition to the PJM stakeholder review, there is another opportunity to evaluate the prudence of transmission projects at FERC. Specifically, AEP's annual transmission formula rate filings include protocols for the review of both the annual projection and true up of the AEP formula rates.

V. THE PROJECT

A. Project Description and Elements

Q. PLEASE DESCRIBE THE WORK THAT IS NEEDED IN THE HAZARD SUBSTATION.

A. Circuit breakers and circuit switchers, along with their associated ancillary equipment, will be added at Hazard station to separate dissimilar zones of protection existing within the station's current arrangement. When a single protective zone includes different element types, for example a bus, a transformer, or a line, additional sectionalizing devices are required to protect each element. Multiple dissimilar zones not only result in an arrangement that is more prone to mis-operation, but it also exposes additional substation elements to dangerous and potentially damaging fault currents. Standard industry practice dictates that circuit breakers and circuit switchers be added to segregate dissimilar zones of protection and protect the new equipment from damage from fault operations when installed.

The installation of a 69 kV circuit breaker connecting 69 kV Bus #1 and Bus #2 will allow for greater operational flexibility during maintenance activities along with potential abnormal system conditions. The 69 kV bus-tie circuit breaker will allow for either 138/69 kV transformer at Hazard station to source the four 69 kV transmission circuits in the event that the other 138/69 kV transformer is out of service due to maintenance or an abnormal system event.

The installation of a three phase 161/138kV spare transformer is necessary to facilitate timely service restoration in the event of a failure on the #3 161/138kV transformer. The 161/138 kV transformer at Hazard station is the only transformer of this voltage class in the AEP Zone. Therefore, a spare transformer is important to have on site, should there be an outage on the existing transformer. Without a spare, lead times on this type of transformer could be up to a year.

Q. PLEASE DESCRIBE THE WORK THAT IS NEEDED IN THE WOOTON SUBSTATION.

A. The installation of surge arrestors on the 161 kV box bay structure on the Hazard Line position will provide overvoltage protection from lightning or switching surges for the

161kV bus insulation. This type of installation is an industry-accepted practice for protecting equipment from potential overvoltage events. The installation of telecommunication fiber equipment for remote monitoring and operation (via SCADA) of equipment and is required to utilize the new fiber path provided by previously approved OPGW telecommunications cable on proposed Hazard – Wooton 161 kV line. Two coupling capacitor voltage transformers (CCVTs) will also be installed on Phase 2 and Phase 3 of the existing 161 kV bus to meet industry-accepted protection and control standards.

B. <u>The Need for the Project</u>

Q. HOW IS THE HAZARD-WOOTON PROJECT CLASSIFIED FOR PURPOSES OF THE PJM RTEP?

A. The Project is classified as both Baseline and Supplemental. The Company initially presented the Project to PJM Stakeholders as a Supplemental Project on November 2, 2017, and December 18, 2017. Nine previously identified Supplemental project components that are required to terminate the previously approved Hazard -Wooton 161 kV transmission line into both the Wooton and Hazard Substations were resubmitted to PJM and reviewed with PJM stakeholders on April 23, 2018, to reclassify them as Baseline components.

Specifically, the Company emphasized that the line relaying and termination equipment associated with the Hazard – Wooton 161 kV line rebuild is required for completion of the baseline work. Clarification was provided that at Hazard station, the 161/138 kV transformer and 138 kV circuit breaker “M” will need to be relocated to accommodate the scope of previously presented baseline work. The relocation of circuit breaker “M” is the reason why the replacement of circuit breaker “M” is now baseline.

Supplemental project information was updated to explain that capacitor bank "BB" no longer needs to be relocated. Information like equipment relocation is not always known when a project is first developed; this information can surface during the detailed engineering phase of the project. Although many of the needs for this Project have both Supplemental and Baseline drivers, the PJM baseline scope of work was adjusted to reflect that the items described above must be completed in order to execute the rest of the previously approved Baseline scope work.

Q. PLEASE DESCRIBE THE GENERAL CONDITION OF THE HAZARD AND WOOTON STATIONS.

A. Hazard Station was originally constructed in the early 1940s. The majority of the major equipment that makes up the station is in a condition that warrants replacement. This includes all three of the transmission transformers at the station and all of the 69 kV circuit breakers. The structures and platforms that make up the station carry concerns associated with their condition and clearances. The communication equipment within the station is outdated and obsolete, with the majority of the relaying being electromechanical relays installed in the 1960s and 1970s. In addition to the identified concerns associated with the station's equipment and structures, the station's existing configuration creates a risk of an outage of the entire station as the result of the failure of a single piece of equipment. It is necessary to sectionalize equipment in the substation to mitigate that risk.

Wooton Station was constructed in 2006 and is in relatively good physical condition. However, the communication equipment at the station is outdated and needs to be upgraded in order to provide monitoring, protection, and remote operation of station equipment. Also, additional surge arresters need to be installed to protect equipment from potential overvoltage events that could damage station facilities.

Q. HOW DOES SECTIONALIZING EQUIPMENT IN A SUBSTATION BENEFIT THE SUBSTATION'S OPERATION?

A. Sectionalizing is a standard practice that allows faults to be isolated. If there is a problem on the electric grid, it needs to be isolated quickly and efficiently. For example, if a transformer has circuit breakers on both the high-side and low-side of the transformer, the circuit breakers can de-energize the transformer and isolate a transformer fault. This action leaves the buses in-service, keeping customers in-service. Without those breakers, the sectionalizing will not happen until it reaches the next circuit breaker, which may be on the line exits of the station, or in some cases, at the next station. Then, the bus and line would need to be de-energized for a transformer fault, impacting more customers, as well as affecting the reliability of the grid. Moreover, in situations where overlapping zones of protection exist, restoration takes a longer time as high speed reclosing (automatic closing of the circuit breakers assuming many faults are temporary in nature) is disabled to avoid damage to expensive equipment such as transformers.

Q. HOW DOES UPGRADING THE EXISTING COMMUNICATIONS EQUIPMENT BENEFIT THE OVERALL OPERATION OF THE SUBSTATIONS?

A. The protective relays are essential to ensure reliable operation of the grid. In addition, transmission operators rely on these relays for information to make real-time operational decisions. The new relays can detect faults and operate more quickly and accurately than the existing relays, restoring customers and minimizing equipment damage. They have the ability to remotely operate the system if needed restoring customers quickly. Most importantly, they are easy to maintain and repair compared to electromechanical and static wire relays that are no longer supported by manufacturers. Additional benefits of the replacing the existing electromechanical relays with microprocessors relays include:

- A single microprocessor relay has to ability to perform multiple functions in comparison to electromechanical relay which is utilized for a singular function, this leads to a decrease in the amount of microprocessor relays required to perform the same task.
- Ability to perform self-diagnostics to identify failures and malfunctions resulting in immediate notification;
- Microprocessors are less sensitive to temperature;
- Microprocessors provide faster and more repeatable operations and flexible system coordination due to their higher level of accuracy and range of setting variables; and
- Microprocessor relays eliminate the mechanical failures that electromechanical relays are susceptible to and have lower maintenance costs.

The new relays will allow for proactive maintenance, can potentially prevent outages, and will enhance the reliability of the system.

VI. SUMMARY OF PROJECT ELEMENTS

Q. HAS THE COMPANY PREPARED A DOCUMENT TO SUMMARIZE THE VARIOUS ELEMENTS OF THE HAZARD-WOOTON PROJECT?

A. Yes. Kentucky Power developed **EXHIBIT 2** to the Application to explain clearly the need for individual project elements, and to provide a better understanding of the relationship between groups of project elements.

Q. PLEASE DESCRIBE THE LAYOUT OF EXHIBIT 2.

A. The Company's Application in Case No. 2017-00328 listed the individual components of the proposed Hazard Substation and Wooton Substation work. The Hazard Substation elements were listed on Exhibit 10 to the earlier application. The Wooton Substation elements were provided in Paragraph 19 of the earlier Application.

<u>EXHIBIT 2</u> to this Application builds on these earlier listings. The left-hand (first) column of **<u>EXHIBIT 2</u>** provides the Previous Identifier from Exhibit 10 for each element from either Exhibit 10 (Hazard Substation) to or Paragraph 19 (Wooton Substation) of the previous Application. This is to facilitate the Commission's review of this Application and to relate it to the earlier application, to the extent the Commission desires to do so.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THIS INFORMATION CAN BE VIEWED?

A. Certainly. Identifier "T" in the first column of **<u>EXHIBIT 2</u>** is the replacement of the existing 138kV/69kV Transformer #2. Grouped under the replacement of the transformer are three additional components (Identifiers S; U; and V) that are necessary components related to the transformer replacement.

The 138kV/69kV Transformer #2 (Identified "T") steps down the 138 kV transmission voltage to the 69 kV subtransmission-level voltage. The Company proposes to replace Transformer #2 because of the dielectric breakdown, accessory damage to the bushings and windings, and the degradation resulting from the number of through faults experienced by the transformer.

Grouped under Identifier "T" are Identifiers "S", "U", and "V". "S" is the replacement of the motor operated air break switch and installation of a circuit switcher on the high side of Transformer # 2. "U" is the installation of a 60 kV breaker with relay control on thelow side of transformer #2. "V" is the replacement of devices for protection associated with Transformer #2.

The fourth column (labeled "Purpose") explains that the work will permit the isolation of Transformer #2 in the event of a fault. The fifth column explains why isolating the transformer in the event of a fault is required.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

VERIFICATION

The undersigned, Kamran Ali, being duly sworn, deposes and says he is the Managing Director of Transmission Planning, American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Kamran Ali

KAMRAN ALI

**STATE OF OHIO)
) SS
 COUNTY OF FRANKLIN)**

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kamran Ali this the 26 day of June, 2019.

Andrea R. Kirsh

Notary Public

My Commission Expires:

ANDREA M. KIRSH, Attorney At La
NOTARY PUBLIC - STATE OF OHIO
MY COMMISSION HAS NO EXPIRATION DATE
SECTION 147.03 R.C.

(SEAL)

1

AEP Guidelines for Transmission Owner Identified Needs

November 2018

Document Control

Document Review and Approval

Action	Name(s)	Title
Prepared by:	Kevin Killingsworth	Principal Engineer, Asset Performance and Renewal
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Approved by:	Kamran Ali	Director, East Transmission Planning
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Review Cycle

Quarterly	Semi-annual	Annual	As Needed
		X	X

Revision History

Version	Revision Date	Changes	Comments
1.0	01/04/2017	N/A	1st Release
2.0	1/18/2018	Format Update	2nd Release
3.0	11/09/2018	Content Additions	3rd Release

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1.0 Introduction

The American Electric Power (AEP) transmission system consists today of approximately 40,000 miles of transmission lines, 3,600 stations, 5,000 power transformers, 8,000 circuit breakers, and operating voltages between 23 kV and 765 kV in three different RTOs – the Electric Reliability Council of Texas (ERCOT), the PJM Interconnection (PJM), and the Southwest Power Pool (SPP), connecting over 30 different electric utilities while providing service to over 5.4 million customers in 11 different states.

AEP's interconnected transmission system was established in 1911 and is comprised of a very large and diverse combination of line, station, and telecommunication assets, each with its own unique installation date, design specifications, and operating history. As the transmission owner, it is AEP's obligation and responsibility to manage and maintain this diverse set of assets to provide for a safe, adequate, reliable, flexible, efficient, cost-effective and resilient transmission system that meets the needs of all customers while complying with Federal, State, RTO and industry standards. This requires, among other considerations, that AEP determine when the useful life of these transmission assets is coming to an end and when the capability of those assets no longer meets current needs, so that appropriate improvements can be deployed. AEP refers to this list of issues as transmission owner identified needs.

AEP's transmission owner identified needs must be addressed to achieve AEP's obligations and responsibilities. Meeting this obligation requires that AEP ensures the transmission system can deliver electricity to all points of consumption in the quantity and quality expected by customers, while reducing the magnitude and duration of disruptive events. Given these considerations, guidelines are necessary to identify and quantify needs associated with transmission facilities comprising AEP's system. AEP identifies the needs and the solutions necessary to address those needs on a continuous basis using an in-depth understanding of the condition of its assets, and their associated operational performance and risk, while exercising engineering judgment coupled with Good Utility Practices [1].

This document outlines AEP's guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. It outlines how AEP identifies assets with needs, and it outlines how solutions are developed and scheduled. Customer service driven projects and transmission owner planning criteria driven projects are addressed in AEP's Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System document [2] and AEP's FERC Form 715 (Part 4) Transmission Planning Reliability Criteria document [2], respectively.

Addressing these owner identified transmission system needs will result in the following benefits:

- Safe operation of the electric grid.
- Reduction in frequency of outage interruptions.
- Reduction in duration of outage interruptions.
- Improvement in service reliability and adequacy to customers.
- Reduction of risk of service disruptions (improved resiliency) associated with man-made and environmental threats.
- Proactive correction of reliability constraints that stem from asset failures.
- Increased system flexibility associated with day-to-day operations.
- Effective utilization of resources to provide efficient and cost-effective service to customers.

2.0 Process Overview

AEP's transmission owner needs identification guidelines are used for projects that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. AEP uses the three-step process shown in Figure 1 and discussed in detail in this document to determine the best solutions to address the transmission owner identified needs and meet AEP's obligations and responsibilities. This process is completed on an annual basis. In developing the most efficient and cost-effective solutions, AEP's long-term strategy is to pursue holistic transmission solutions in order to reduce the overall AEP transmission system needs.

Figure 1 – AEP Process for Addressing Transmission Owner Identified Needs

3.0 Step 1: Needs Identification

Needs Identification is the first step in the process of determining system and asset improvements that help meet AEP's obligations and responsibilities. AEP gathers information from many internal and external sources to identify assets with needs. A sampling of the inputs and data sources is listed below in Table 1.

Table 1 – Inputs Considered by AEP to Identify Transmission System Needs

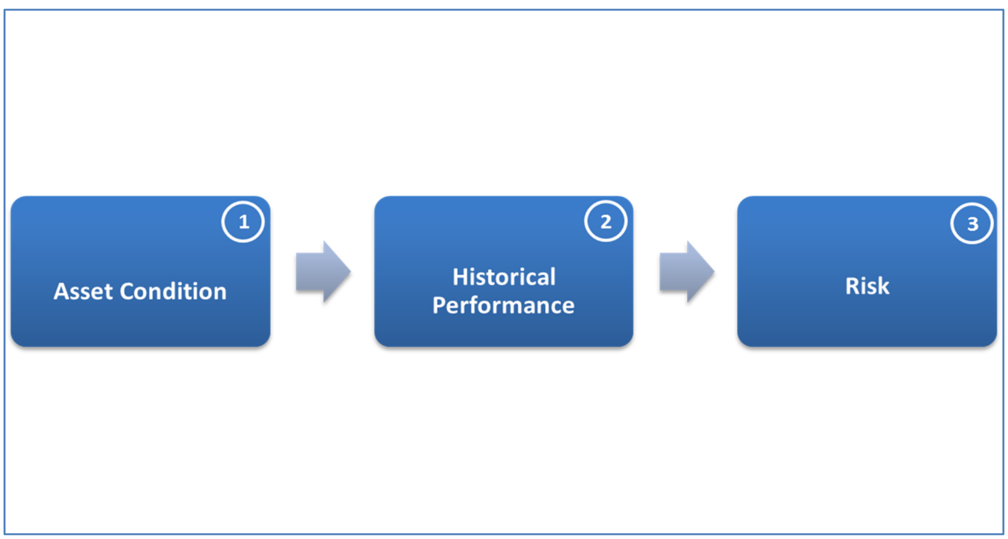
Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperations; Voltage unbalance
	Legacy system configurations	Ground switch protection schemes for transformers;; Transmission Line Taps without switches (hard taps); Equipment without vendor support
	Outage duration and frequency	Outages resulting from equipment failures, misoperations, or inadequate lightning protection
	Operations and maintenance costs	Costs to operate and maintain equipment
External	Regional Transmission Operator (RTO) or Independent System Operator (ISO) issued notices	Post Contingency Local Load Relief Warnings (PCLLRWs) issued by the RTO that can lead to customer load impacts
	Stakeholder input	Input received through stakeholder meetings, such as PJM's Sub Regional RTEP Committee (SRRTEP) meetings or through the AEP hosted Annual Stakeholder Summits
	Customer feedback	Voltage sag issues to customer delivery points due to poor sectionalizing; frequent outages to facilities directly affecting customers
	State and Federal policies, standards, or guidelines	NERC standards for dynamic disturbance recording
Both	Environmental and community impacts	Equipment oil/gas leaks; facilities currently installed at or near national parks, national forests, or metropolitan areas
	Standards and Guidelines	Minimum Design Standards, Radial Lines, Three Terminal Lines, Overlapping Zones of Protection
	Safety risks and concerns	Station and Line equipment that does not meet ground clearances; Facilities identified as being in flood zones; New Occupational Safety and Hazards Administration (OSHA) regulations

This information is reviewed and analyzed to identify the transmission assets that are not performing properly or are preventing the proper operation of the transmission system.

3.1 Methodology and Process Overview

The AEP transmission system is composed of a very large number of assets that provide specific functionality and must work in conjunction with each other in the operation of the grid. These assets have been deployed over a long period of time using engineering principles, design standards, safety codes, and Good Utility Practices that were applicable at the time of installation and have been exposed to varying operating conditions over their life. The Needs Identification methodology is shown below in Figure 2. AEP addresses the identified needs considering factors including severity of the asset condition and overall system impacts. These are subsequently evaluated versus constraints such as outage availability, siting requirements, availability of labor and material, constructability, and available capital funding in determining the timing and scope of mitigation.

Figure 2 – Needs Identification Methodology



It is AEP's strategy to develop and provide the most efficient, cost-effective, and holistic long-term solutions for the identified needs.

3.2 Asset Condition (Factor 1)

The Asset Condition assessment gathers a standard set of physical characteristics associated with an asset or a group of assets. The set of data points recorded is determined based on the asset type and class. Information assembled during the Asset Condition assessment is used to show the historical deterioration, current condition, and future expectation of the asset or group of assets on the AEP system.

AEP annually assembles a list of reported condition issues for all of its assets in its system. A detailed follow-up review is conducted to determine if a transmission asset is in need of upgrade and/or replacement. Additionally, this Asset Condition review is used to determine an adequate scope of work required to mitigate the risk associated with a facility's performance and its identified issues. This level of risk is determined through the Future Risk assessment (Factor 3).

Beyond physical condition, AEP's ability to restore the asset in case of a failure is also considered. This is referred to as the future probability of failure adder. Typically, assets that are no longer supported by manufacturers or lack available spare parts are assigned a higher probability of failure adder.

To perform condition assessments, AEP classifies its Transmission assets in two main categories: Transmission Lines and Substations.

3.2.1 Transmission Line Considerations

Design Portion

A. Age (Original Installation Date)
B. Structure Type (Wood, Steel, Lattice)
C. Conductor Type (Size, Material & Stranding)
D. Static Wire Type (Size & Material)
E. Foundation Type (Grillage, Direct Embed, Caison, Guyed V, Drilled Pier etc.)
F. Insulator Type (Material)
G. Shielding and Grounding Design Criteria (Ground Rod, Counterpoise, "Butt Wrap" etc.)
H. Electrical Configuration

a. Three Terminal Lines

b. Radial Facilities

I. NESC Standards Compliance

a. Structural Strength (NESC 250B, 250C & 250D Compliance)

b. Clearances (TLES-047 Compliance)

J. Easement Adequacy (Width, Encroachments, Type; etc.)

Physical Condition

A. Open Conditions (existing and unaddressed physical conditions associated with a Transmission Line component)

B. Closed Conditions (previously addressed physical conditions associated with a Transmission Line component)

C. Emergency Fixes (History of emergency fixes)

D. Accessibility (Identified areas of difficult access)

3.2.2 Substation Considerations

A. Transformers

a. Manufacturer

b. Manufacturing Date

c. In Service Date

d. Load Tap Changer Type & Operation History (if applicable)

e. Dissolved Gas Analysis

f. Bushing Power Factor

g. Through Fault Events (Duval Triangles)

h. Moisture Content (Oil)

i. Oil Interfacial Tension

j. Dielectric Strength

k. Maintenance History

l. Malfunction Records

B. Circuit Breakers

a. Manufacturer & Type

b. Manufacturing Date
c. In Service Date
d. Interrupting Medium
e. Fault Operations
f. Switched Operations
g. Spare Part Availability
h. Maintenance History
i. Malfunction Records
j. Breaker Type Population

C. Secondary/Auxiliary Substation Equipment*

a. Station Batteries
b. Control House
c. Station Security
d. Station Structures
e. Capacitor Banks
f. Bus, Cable and Insulators
g. Disconnect Switches
h. Station Configuration
i. Station Service
j. Relay Types
k. RTU Types
l. Voltage Sensing Devices

**AEP substation inspections include assessments of secondary/ancillary equipment. If needed, upgrades to these components are typically included in the scope of projects addressing major equipment and may not necessarily drive stand-alone projects.*

3.3 Historical Performance (Factor 2)

AEP's Historical Performance assessment quantifies how an asset or a group of assets has historically impacted the Transmission system's reliability and Transmission connected customers, helps identify the primary contributing factors to a facility's performance, and baselines the outage probability used in our Future Risk analysis. The metrics used as part of this historical performance assessment include:

A. Forced Outage Rates
B. Manual Outage Rates
C. Outage Durations (Forced Outage Duration in Hours)
D. System Average Interruption Indices (T-SAIDI, T-SAIFI, T-SAIFI-S, T-MAIFI)
E. Customer Minutes of Interruption (CMI)
F. Customer Average Interruption Indices (IEEE SAIDI, CAIDI & SAIFI)
G. Number of Customers Interrupted (CI)

AEP utilizes this standard set of metrics as a means to quantify the historical performance of an asset. These historical performance metrics allow AEP to further investigate assets that have historically impacted customers the most.

Due to the vast size of the AEP operating territory covering 11 states, AEP segments its needs into seven distinct operating company regions and six voltage classes. This segmentation ensures that variations in geography with respect to vegetation, weather patterns, and terrain can be accounted for within the process of identifying needs for each operating company area. In addition to customers of AEP operating companies, consideration for retail customers that are served at non-AEP wholesale customer service points is also included. In order to account for customers served behind wholesale meter points, AEP gathers information from the parent wholesale provider or in its absence, applies a surrogate customers per MW ratio to estimate the number of customers served by a wholesale power provider's delivery point. This customer count is used to calculate the individual metrics above.

AEP's standard approach is to annually review the historical performance of its assets based on a rolling three-year average, but in some cases AEP may extend the review period beyond three years. AEP classifies all transmission asset outage causes into the following five categories to conduct this review: Transmission Line Component Failure, Substation Component Failure, Vegetation (AEP), Vegetation (Non-AEP), and External Factors. Each transmission asset and its associated performance is quantified and compared against corresponding system totals to determine its percentage contribution to aggregated system performance. An evaluation of outage rates is also performed for Transmission line assets. The observed performance of the assets in any of these categories can point to a need that may need to be addressed.

3.4 Future Risk (Factor 3)

AEP reviews the associated risk exposure (future risk) inherent with each identified asset to determine an asset's level of risk. This risk exposure is quantified assuming the probability of an outage scenario and is based on the reported condition of the asset and the severity of that condition and what the impact could be to customers or to the operation of AEP's Transmission system. Some of the key items to assess these impacts included in the risk criteria are:

A. Number of Customers Served
B. Load Served
C. Operational Risks
    a. Post Contingency Load Loss Relief Warnings (PCLLRW's)
    b. History of Load Shed Events
    c. Stations in Black Start Paths

In addition to the future risk calculation performed through this process, AEP is systematically reviewing its system to identify and remediate equipment and practices that have resulted in operational, restoration, environmental, or safety issues in the past that cannot be directly quantified, but that remain as acknowledged risks in the AEP Transmission system. These include:

A. Wood pole construction
B. Pilot wire protection schemes
C. Oil circuit breakers
D. Air Blast circuit breakers
E. Pipe type oil filled cables
F. Electromechanical relays
G. Legacy system configurations
    a. Missing or inadequate line switches (e.g., hard-taps)
    b. Missing or inadequate transformer/bus protection

c. Three-terminal lines

d. Overlapping zones of protection

H. Non-Standard Voltage Classes

I. Poor Lightning & Grounding Performance

J. Radial Facilities

K. Public vulnerability

These items as described above are reviewed on a case by case basis and considered when holistic system solutions are being developed.

4.0 Step 2: Solution Development

The development of solutions for the identified needs considers a holistic view of all of the needs in which several solution options are developed and scoped. AEP applies the appropriate industry standards, engineering judgment, and Good Utility Practices to develop these solution options. AEP solicits customer and external stakeholder input on potential solutions through the Annual Stakeholder Summits hosted by AEP and also through the PJM Project Submission process. This ensures that input from external stakeholders on identified needs can be received and considered as part of the solution development process.

Solution options consider many factors including, but not limited to, environmental conditions, community impacts, land availability, permitting requirements, customer needs, system needs, and asset conditions in ultimately identifying the best solution to address the identified need. Once the selected solution for a need or group of needs is defined, it is reviewed using the current RTO provided power-flow, short circuit, and stability system models (as needed) to ensure that the proposed solution does not adversely impact or create planning criteria violations on the transmission grid. Finally, AEP reviews its existing portfolio of planning criteria driven reliability projects and evaluates opportunities to combine or complement existing planning criteria driven reliability projects with the transmission owner needs driven solutions developed through this process. This step ultimately results in the implementation of the most efficient, cost-effective, and holistic long-term solutions. Stand-alone projects are created to implement the proposed solution where transmission owner needs driven solutions cannot be integrated into existing projects.

5.0 Step 3: Solution Scheduling

Once solutions are developed to address the identified needs, the scheduling of the solutions will take place. As mentioned in the previous section, if opportunities exist to combine or complement existing planning criteria driven reliability projects with the needs driven solutions developed through this process, the scheduling will be aligned to the extent possible. In all other situations, AEP will schedule the implementation of the identified solutions in consideration of various factors including severity of the asset condition, overall system impacts, outage availability, siting requirements, availability of labor and material, constructability, and available capital funding. AEP uses its discretion and engineering judgment to determine suitable timelines for project execution.

6.0 Conclusion

This document outlines AEP's guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. It outlines the sources and methods considered by AEP to identify assets with needs on a continuous basis and it outlines how solutions are developed and scheduled. AEP will review and modify these guidelines as appropriate based upon our continuing experience with the methodology, acquisition of data sources, deployment of improved performance statistics and the receipt of stakeholder input in order to provide a safe, adequate, reliable, flexible, efficient, cost-effective and resilient transmission system that meets the evolving needs of all of the customers it serves.

7.0 References

[1] FERC Pro Forma Open Access Transmission Tariff, Section 1.14, Definition of "Good Utility Practice". Link: https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt

[2] AEP Transmission Planning Documents and Transmission Guidelines.
Link: http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/