I&M Exhibit: _____

Cause No. 45235

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

KAMRAN ALI

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PRE-FILED VERIFIED DIRECT TESTIMONY OF KAMRAN ALI
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Kamran Ali. My business address is 8500 Smiths Mill Road, New Albany, Ohio 43054.

Q. By whom are you employed and in what capacity?

A. 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 Indiana Michigan Power Company (I&M or the Company).

Q. Please briefly describe 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 was employed by SMC Electrical in 2004 as an electrical engineer. In 2006, I joined AEP as a Substation Engineer. 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, Transmission Planning, which includes organizing and managing all activities related to assessing the adequacy of AEP's transmission network to meet the needs of its customers 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 and submitted testimony before the Indiana Utility Regulatory Commission (Commission), the Michigan Public Service Commission, the Kentucky Public Service Commission, Maryland Public Service Commission, and the Pennsylvania Public Utility Commission on behalf of various other electric operating companies of the AEP system.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes the transmission system that is necessary for the provision of retail service and supports the recovery of the transmission costs charged to I&M as a result of its membership in the PJM RTO. In particular, I&M incurs charges under the PJM tariffs approved by the Federal Energy Regulatory Commission (FERC), including the PJM Open Access Transmission Tariff (PJM OATT). My testimony supports the nature and reasonableness of those costs and demonstrates that the Off System Sales Margin Sharing/PJM Cost Rider (OSS/PJM Rider) remains an appropriate recovery mechanism. Company witness Williamson details the Company's proposals in this proceeding regarding the OSS/PJM Rider. Company witness Nollenberger describes how I&M's traditional embedded transmission costs and I&M's revenues as a PJM transmission owner are removed from I&M's cost of service for the purposes of this proceeding.

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I support the following attachments:

- Attachment KA-1 – AEP Guidelines for Transmission Owner Identified Needs
- Attachment KA-2 - Presentation Slides from the April 23, 2019 Meeting of the Subregional RTEP Committee – Western
- Attachment KA-3 – AEP Transmission Agreement

Q. Were these attachments prepared or assembled by you or under your direct supervision?

A. Yes.

II. I&M'S TRANSMISSION SYSTEM

Q. Please describe I&M's transmission system.

A. I&M's transmission system is a highly networked grid that delivers electricity from generation sources to the retail and wholesale consumers served by I&M. There are approximately 4,900 circuit miles of transmission lines in the I&M system, stretching from the eastern Indiana border with Ohio to the shore of Lake Michigan in southeastern Michigan, as well as extending to western and southeastern Indiana, connecting current and former I&M generation sources with the Company's service territory. Approximately 4,100 of these circuit miles are within Indiana. The voltage levels of I&M's transmission system range from 34.5 kV to 765 kV and can be divided into three categories based on voltage level: extra high voltage (EHV) (above 200 kV), transmission (100 kV to 200 kV), and sub-transmission (34.5 kV to 100 kV). Finally, I&M's transmission system includes approximately 187 transmission substations, 140 of which are located in Indiana.

Q. Please explain how I&M's transmission system is interconnected with the transmission system of other electric utilities.

A. The I&M transmission system is part of the PJM RTO and is interconnected with Ohio Power Company, American Transmission Systems, Inc., Dayton Power and Light Co., ComEd, and transmission providers in the Midcontinent Independent System Operator (MISO) RTO. I&M is also interconnected with various rural electric cooperatives and municipal electric utilities.

Q. Please describe the overall condition of I&M's transmission plant.

A. The Company's transmission facilities are revitalized and maintained in accordance with AEP standards that are based on industry regulations and good utility practices. Like other members of our industry, the Company is addressing the challenges of aging infrastructure along with the need to modernize transmission facilities, comply with regulations, and adapt to a changing generation portfolio.

Q. Please explain.

A. The AEP transmission system has evolved over the last century. In the recent past, the majority of transmission investment has been directed towards constructing facilities to address RTO-identified constraints due to a shift in generation portfolio. In addition, some investment has focused on connecting new demand while maintaining compliance with changing federal and regional reliability standards. More recently, investment has been refocused to address aging grid infrastructure and resilience, to maintain and improve reliability, and to protect the grid from physical and cyber threats.

Finally, I&M expects that the transmission system will continue to evolve and change through technological advancements such as the adoption of electric vehicles, integration of renewable resources, retirement of fossil fuel based generation, and the implementation of new customer programs.

Q. Is I&M's transmission system currently adequate to serve its customers' load reliably?

A. Yes. I&M's transmission system is compliant with all federal and regional reliability standards. I&M will continue to invest appropriately in its transmission assets to provide reliable electric service to its customers.

Q. How are AEP and I&M addressing the issue of aging transmission infrastructure?

A. Transmission assets on the I&M system are aging. For example, I&M generally considers 70 years to be the life expectancy for conductors. As of January 2019, I&M's average conductor age was roughly 49 years of service. Additionally, over 1,200 line miles are 60 years of age or older.

Although asset age is an important consideration, AEP and I&M develop transmission projects based on a number of factors, including the performance and condition of each asset and the risk that the failure of each poses to the system and connected customers. As the I&M infrastructure continues to age, the associated risk for any given asset increases. AEP and I&M are implementing solutions to address these needs on the system.

III. PJM INTERCONNECTION

Q. What is PJM?

A. FERC Order 2000 introduced the concept of an RTO or 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 I&M's transfer of functional operation of its transmission facilities to PJM by its Order dated September 20, 2003, in consolidated Cause Nos. 42350 and 42352. The AEP System–East Zone (AEP Zone), which includes I&M, integrated its operations with PJM and began participating in the PJM energy market on October 1, 2004.

Q. How do PJM and AEP coordinate planning and operation of I&M's transmission system?

A. I&M'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 I&M and AEP Indiana Michigan Transmission Company. This expansive system allows the economical and reliable delivery of electric power for all AEP customers.

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. I&M has input into the RTO planning process through AEP Transmission, but the costs allocated to I&M for the grid infrastructure investment in PJM outside I&M's service territory are not within I&M's direct control.

Q. How does I&M participate in PJM?

A. I&M currently has three distinct roles within PJM: (1) Generator, (2) Load Serving Entity (LSE), and (3) Transmission Owner (TO). There are various charges and credits that the Company experiences resulting from each role. I will primarily discuss the roles of an LSE and TO.

Q. How is I&M charged for using the PJM transmission system?

A. As an LSE, I&M is charged for costs associated with the functional operation of the transmission system, management of the PJM markets, and general administration of the RTO, irrespective of whether it owns the facilities that are being used. As such, I&M pays to use the PJM transmission system, including its own assets, through charges that are based upon I&M's demand on the system. The costs include charges for I&M's purchase of Network Integration Transmission Service (NITS) under the PJM OATT to serve its retail customers. I&M can incur NITS costs due to projects constructed by other transmission owners within the AEP Zone. I&M can also incur Transmission Enhancement Charges for projects constructed by other transmission owners outside of the AEP Zone.

Q. Does I&M receive compensation from PJM as a TO?

A. Yes. I&M is compensated by PJM for owning and operating transmission assets as a TO.

Q. Please identify the types of PJM transmission costs incurred by I&M.

A. I&M incurs costs and offsetting revenues in accordance with the FERC-approved PJM OATT and Operating Agreement, which currently include the following:

- NITS pursuant to PJM OATT Attachments H-14 and H-20.
- Firm and Non-Firm Point-to-Point (PTP) Revenues pursuant to PJM OATT Schedules 7 and 8.
- TO Scheduling, System Control, and Dispatch Service pursuant to PJM OATT Schedule 1A.
- AEP RTO Start-up Cost Recovery Charges (SCRC) pursuant to PJM OATT Attachment H-14.
- PJM RTO Administration fees and other charges pursuant to PJM OATT Schedules 9 and 10.
- PJM Transmission Enhancement Charges pursuant to PJM OATT Schedule 12.
- Default Allocation Assessments, and any refunds of such assessments, pursuant to Section 15.2 of the PJM Operating Agreement.

From time to time, PJM modifies the charges and revenues related to membership within PJM and for transmission service; as a result, the list above may not be fully representative of I&M's PJM-related charges and revenues in the future.

Q. What are PJM NITS charges?

A. NITS charges represent the cost for I&M and other PJM network customers to integrate, economically dispatch, and regulate their current and planned network resources to service their network load. NITS charges in the AEP Zone are derived from the transmission investments of all TOs in the AEP Zone.

Q. Please identify other PJM costs incurred by I&M.

A. I&M incurs expenses and receives credits from PJM for other activities associated with I&M's role as a Generator and LSE. These charges and credits include net transmission congestion charges and other ancillary services such as:

- Scheduling, System Control & Dispatch Service;
- Reactive Supply and Voltage Control Service;
- Regulation and Frequency Response Service;
- Synchronized Reserve Service;
- Supplemental Reserve Service; and
- Black Start Service.

These expenses are included in the "Non-NITS" costs in Figure KA-2 below.

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

Q. Please describe the PJM Regional Transmission Expansion Plan (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. AEP Transmission participates on I&M's behalf in the PJM planning process, which is guided by PJM, NERC, ReliabilityFirst Corporation (RFC) and AEP planning criteria. The process results in three different categories of projects: Baseline Upgrades, Network Upgrades and Supplemental Upgrades (also called "Owner Projects"). Each category is described below.

The first project category is Baseline Upgrades. Using the aforementioned criteria and guidelines, PJM and I&M, in conjunction with AEP, identify needs that are a result of a criteria violation. 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 requirements 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 cost of Baseline Upgrades are allocated to the benefiting zones based on the following mechanisms[1]:

- 345 kV single-circuit or lower voltage facilities are cost allocated based on solution-based distribution factors (DFAX).
- The costs of a 345 kV double-circuit or higher voltage facilities are allocated as follows:

[1] The latest published material describing PJM cost allocation procedures for the RTEP process can be found in PJM Manual 14B located at: https://www.pjm.com/-/media/documents/manuals/m14b.ashx

    - 50% of project costs are allocated to all PJM zones based on load ratio share (the AEP Zone load share percentage for January to December 2019 is 14.1%).
    - 50% of project costs are allocated on DFAX basis.
- For market efficiency projects, Net Load Payment savings is used instead of DFAX to determine cost allocation. Net Load Payment savings is the net present value sum of energy and capacity market benefits for all benefiting transmission zones.

The second project category is Network Upgrades. These transmission projects result from transmission customer requests for generator interconnection, merchant transmission additions, and long-term transmission service. Customers that cause the need for Network Upgrades are responsible for the costs that are incurred. As an example, if a generator requested to connect to a transmission line and an upgrade was required to connect the generator, the generator would pay for the network upgrade.

The third project category is Owner Projects. These projects are needed for many reasons, including regulatory requirements, modernization and hardening of the grid, replacement of failed equipment, proactive replacement of deteriorating assets prior to failure and improved operational efficiency and performance. A further discussion on the drivers that I&M considers in identifying Owner Projects can be found later in my testimony. The costs of Owner Projects are allocated to the transmission zone in which they are built.

Q. Do I&M and other Transmission Owners in the AEP Zone follow specific guidelines to determine the necessity of Owner Projects?

A. Yes. All AEP affiliated transmission owners follow an established and detailed protocol to evaluate and select Owner Projects that assures only projects that are needed in each transmission owner's service territory are pursued. See Attachment 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 evaluations, while each Transmission Owner ultimately determines the mix of Owner Projects needed to maintain the reliability of their transmission grid within the AEP Zone.

Q. What drivers or inputs does I&M consider in identifying Owner Projects?

A. Consistent with the AEP Guidelines for Transmission Owner Identified Needs, the drivers considered in identifying Owner Projects 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 in established standards, state policy objectives, etc.

Q. Are these drivers under I&M's exclusive control?

A. No. Although I&M commits significant resources to reduce safety risks, maintain transmission assets consistent with industry practices, and plan capital investment to increase reliability performance, many of the drivers of Owner Projects are outside of I&M's control and include regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems. Although I&M has some control over its own specific asset replacement if the replacement is made before the asset's failure, many of the underlying drivers of asset performance such as equipment age, equipment abnormalities, and environmental conditions are also outside of the Company's control.

Q. Can you provide an example of an I&M Owner Project that supports these considerations?

A. I&M began construction on the Hartford City-Montpelier Transmission Line Rebuild Project in fall 2018, with project completion expected in spring 2019. The 69-kilovolt (kV) transmission line that connects the Hartford City Substation to the Montpelier Substation in east central Indiana had reached a state where it was in need of replacement. Condition and performance issues that were considered in the decision to rebuild included but were not limited to:

- 1960s wood pole construction
- 24 open conditions (degrading structures, damaged conductor, etc.)
- 13 momentary and 3 permanent outages in the last 5 years
- Over 500,000 customer minutes of interruption (CMI)

As part of the upgrade, approximately 8.5 miles of aging wood poles that do not meet current National Electrical Safety Code (NESC) standards will be replaced with steel monopole structures that are able to support higher capacity conductors and more readily withstand adverse weather conditions. The improvements in Blackford County will be essential to ensure continued reliable electricity is available for local customers. Proactive improvements like this example serve to reduce power outages and speed recovery of service when outages do occur.

Q. What is PJM's role in reviewing Owner Projects?

A. All projects affecting the topology of the grid, whether PJM identified or Transmission Owner identified, are subject to the stakeholder process within PJM.

While PJM does not formally "approve" Owner Projects, these projects are submitted to PJM and reviewed with the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee – Western on a periodic basis in accordance with Attachment M-3. All TEAC and Subregional RTEP Committee – Western meetings are open and any transmission stakeholder can attend and participate. Stakeholder input regarding specific projects is vetted through this PJM committee meeting process. Attachment KA-2 contains presentation slides on I&M Owner Projects that were reviewed at the Subregional RTEP Committee – Western on April 23, 2019[2]. As shown on Attachment KA–2, Owner Projects are subject to multiple rounds of review and detailed project information, including alternative solutions, is provided to stakeholders. Figure KA-1 provides a table of scheduled meeting dates for the Subregional RTEP Committee - Western:

Figure KA-1
Upcoming Subregional RTEP Committee – Western Dates

Date	Time
5/20/2019	12:00 p.m. - 4:00 p.m. EPT
6/17/2019	12:00 p.m. - 4:00 p.m. EPT
7/22/2019	12:00 p.m. - 4:00 p.m. EPT
8/27/2019	12:00 p.m. - 4:00 p.m. EPT
9/24/2019	12:00 p.m. - 4:00 p.m. EPT
10/21/2019	12:00 p.m. - 4:00 p.m. EPT
11/18/2019	12:00 p.m. - 4:00 p.m. EPT
12/16/2019	12:00 p.m. - 4:00 p.m. EPT

[2] Additional meeting materials are available from PJM's website at: https://www.pjm.com/committees-and-groups/committees/srrtep-w.aspx

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. FORECAST OF PJM REVENUES AND CHARGES

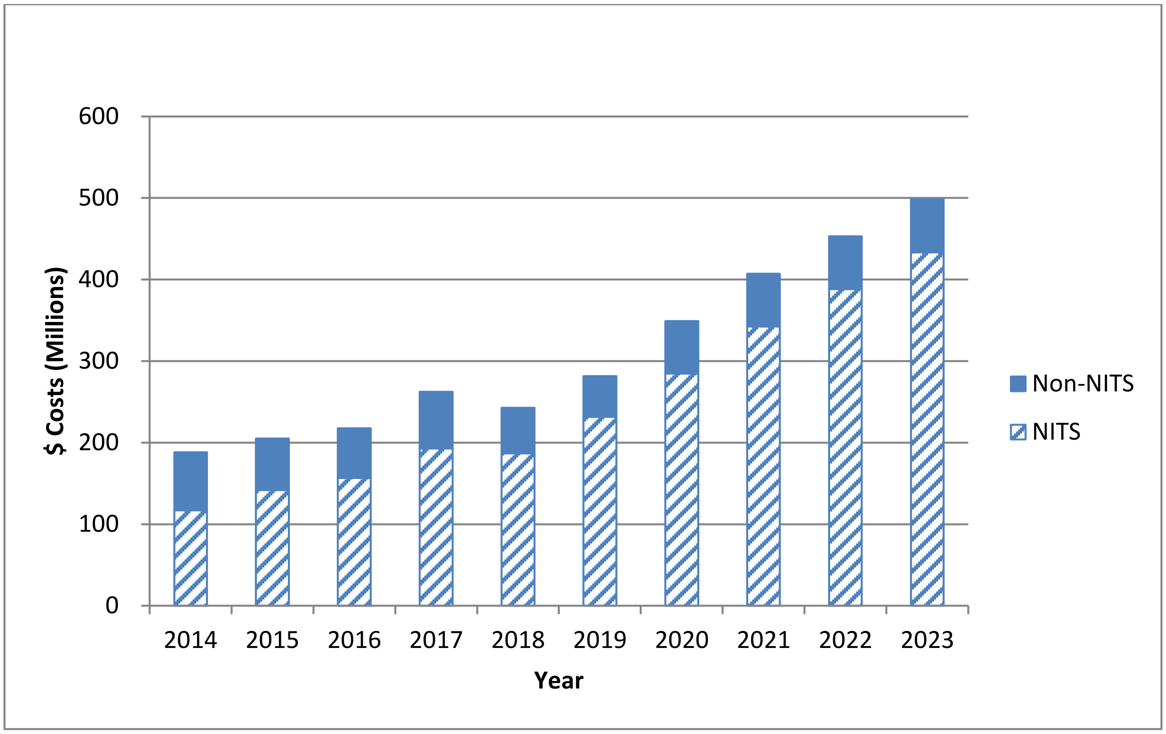
Q. Please explain the development of the forecasted PJM revenues and costs.

A. The forecasted PJM charges are developed internally by AEP and its affiliated companies that have projected transmission investments over the forecasted period. The forecast methodology is described in detail by witness Heimberger; however, at a high level, the projected necessary capital investment, combined with the required operations and maintenance expense, is modeled to develop an estimated revenue requirement for I&M's projected transmission in service. Through an analysis of historical and forecasted transmission system usage, the forecasted amount to be allocated to I&M through its role as an LSE is determined. The results of that process are included in Figure KA-2 shown below.

Q. What is the Company's forecast of PJM costs for beyond the Test Year?

A. I&M's total PJM costs for 2014-2018 are shown in Figure KA-2 below. The forecast period from 2019 through 2023, including the 2020 Test Year, is also provided. Figure KA-2 also breaks out the amount of PJM NITS costs to demonstrate the significance of the PJM NITS costs compared to the total PJM transmission costs.

Figure KA-2
I&M Historical and Forecasted PJM Costs (Total Company)



As stated above and discussed below, increases in the Company's PJM costs are being driven primarily by the PJM NITS costs. In particular, PJM NITS costs are growing primarily due to charges in Accounts 4561035 and 5650016, which are billed by PJM to I&M in its role as the LSE for I&M's native load customers. Charges to these, and other NITS accounts, will continue to be incurred and are forecasted to be approximately $284.7 million (Total Company) for the Test Year. In addition, I&M is forecasted to incur approximately $64.4 million (Total Company) in non-NITS costs in the Test Year. As explained later in my direct testimony, I&M is responsible for the costs associated with infrastructure investment in the greater region of PJM's transmission system, and thus the charges for which I&M is responsible are not fully controllable by the Company.

Q. What is driving the increase in NITS charges for I&M?

A. The increase in NITS charges is being driven by investment in transmission infrastructure. In recent history, transmission investment was focused on system needs arising from retirement of generation due to environmental regulations. As previously described, the transmission system requires substantial investment to address aging infrastructure, cyber and physical security threats, and modernization of protection and control equipment. This requires infrastructure improvements occurring both within I&M's service territory and the remainder of the AEP Zone. The costs associated with these investments are billed to the AEP Zone and charged to I&M through the monthly PJM bill and the AEP Transmission Agreement.

Q. Are projects within the AEP Zone the only project type contributing to transmission charges from PJM?

A. No. Transmission projects that solely benefit the AEP Zone are fully allocated to all LSEs in the AEP Zone, including I&M, and these costs are included in NITS charges. The cost of transmission projects that benefit more than one PJM zone are shared over the larger PJM footprint as determined by PJM. As a result, I&M may incur costs from multi-zonal projects, which are included in non-NITS charges.

Q. Is the need for transmission infrastructure investment unique to I&M or PJM?

A. No. Industry wide, utilities are investing in the transmission system to meet the above-described needs. Nationally, transmission investment has increased steadily over the past 10 years. I&M expects robust levels of investment will continue beyond the test year.

VI. COSTS RECOVERED THROUGH THE OSS/PJM RIDER

Q. How are NITS costs billed to I&M?

A. NITS costs are billed to I&M in accordance with FERC approved tariffs, the PJM OATT and AEP's Transmission Agreement. I&M recovers these costs through the OSS/PJM Rider.

Q. What are the established criteria for cost recovery through the OSS/PJM Rider?

A. As Company witness Williamson explains, in determining whether to approve the tracking of costs, the Commission considers whether the costs are (1) collectively and potentially significant; (2) potentially variable or volatile; and (3) largely outside the utility's control. My testimony identifies these PJM costs and explains how they satisfy these three criteria. The incremental growth is evidenced by the change in expenses over the period 2014 through 2018 as well as I&M's forward-looking test year January 1, 2020 through December 31, 2020 (Test Year) and beyond.

Q. Are these costs consistent with the costs currently recovered through I&M'S OSS/PJM Rider?

A. Yes. This is further discussed by Company witness Williamson.

Q. Are the PJM costs charged to I&M collectively significant?

A. Yes. As shown on Figure KA-2, which provided historical PJM costs incurred by I&M from 2014 through 2018 and forecasted PJM costs from 2019 through 2023, both the Non-NITS and NITS costs are significant and the NITS costs in particular are expected to increase.

Q. Are these costs charged to I&M potentially variable or volatile?

A. Yes. There are costs related to ensuring an adequate transmission system is available to provide service. These costs flow to I&M through the PJM tariffs and, as shown in Figure KA-2, vary from year to year. The transmission capital additions for I&M include both PJM and Owner identified projects that are needed to maintain a reliable transmission grid. In some years, greater or fewer transmission projects may be completed by I&M. The same is true for other transmission owners in the AEP Zone and this contributes to the volatility of the NITS costs.

Q. Can NITS costs include PJM baseline projects?

A. Yes. As I mentioned earlier, PJM baseline projects are included in the NITS rate if they are 100 percent allocated to the AEP Zone. This further contributes to the volatility of NITS costs.

Q. Are NITS costs largely outside of I&M's control?

A. Yes, they are. The drivers of the cost increases are due to the transmission system requiring substantial investment to address the considerations I previously discussed. As I explained earlier, each of the drivers of cost increases is largely or entirely outside the control of I&M and other transmission owners. However, each transmission owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain the reliability of the transmission grid. The FERC-approved AEP Transmission Agreement, to which I&M is a member, requires "[e]ach member [to] maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner." The Transmission Agreement is attached as Attachment KA-3. Consistent with that obligation, I&M will evaluate, prioritize, and select the Owner Projects that are necessary to provide a reliable transmission grid within its service territory.

Q. Are NITS charges reasonable and necessary?

A. Yes. NITS costs are a necessary cost to maintain the reliability of the transmission grid and ensure equal access by all users of the transmission system. To ensure that Owner Project needs are clearly understood by stakeholders, they are vetted with stakeholders through PJM hosted stakeholder meetings. This transparent planning and vetting process ensures that Owner Projects that are incorporated into the RTEP are appropriate, efficient, and cost-effective solutions to planning criteria and system needs that benefit customers.

VII. SUMMARY

Q. Please summarize your testimony.

A. The transmission system is necessary for the provision of retail service and investment in transmission infrastructure is needed to: address aging infrastructure; ensure better telecommunication connectivity to support supervisory control; install and improve data acquisition & protection systems; ensure physical and cyber security of critical assets; and reduce CMI related to transmission outages.

Increases in the Company’s PJM costs are being driven primarily by the PJM NITS costs, which reflect increased transmission spending across the AEP Zone. In addition, NITS costs are significant, volatile and largely outside the control of I&M. Further, extensive AEP and PJM processes for review and stakeholder input ensure that only projects that are reasonable and necessary are approved and implemented. As such, recovery of NITS costs through I&M’s OSS/PJM Rider remains a reasonable process for the recovery of I&M’s portion of the total NITS costs for the AEP Zone.

Q. Does this conclude your pre-filed verified direct testimony?

A. Yes it does.

VERIFICATION

I, Kamran Ali, Managing Director of Transmission Planning of American Electric Power Service Corporation (AEPSC), affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: MAY 8, 2019

Kamran Ali

Kamran Ali

AEP Guidelines for Transmission Owner Identified Needs

November 2018

Document Control

Document Review and Approval

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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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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

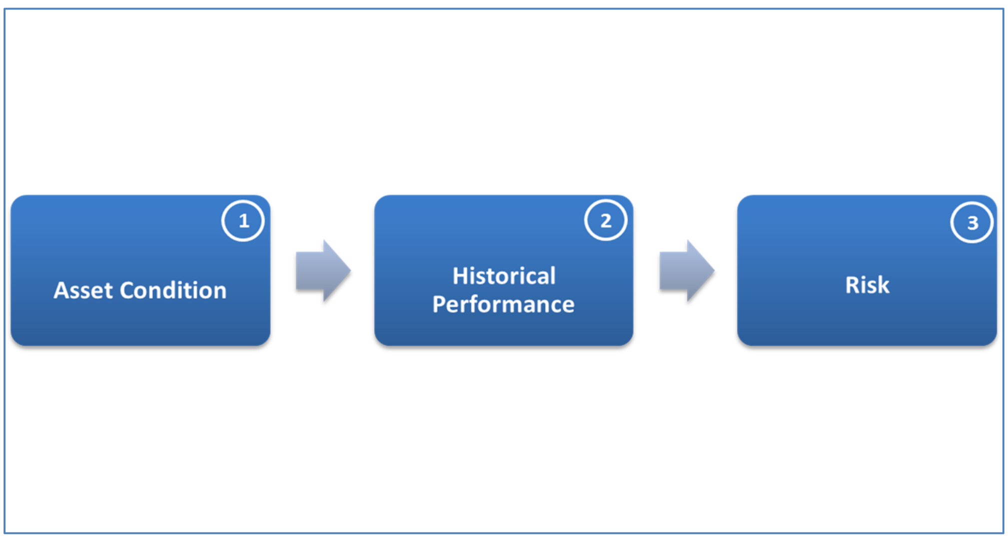
Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperations; Voltage unbalance
	Legacy system 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/

PJM Western SRRTEP Committee
AEP Supplemental Projects

April 23, 2019

Needs

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

AEP Transmission Zone M-3 Process
Indiana & Michigan

Need Number: AEP-2019-IM009

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

<u>Bridgman 69 kV Station</u>

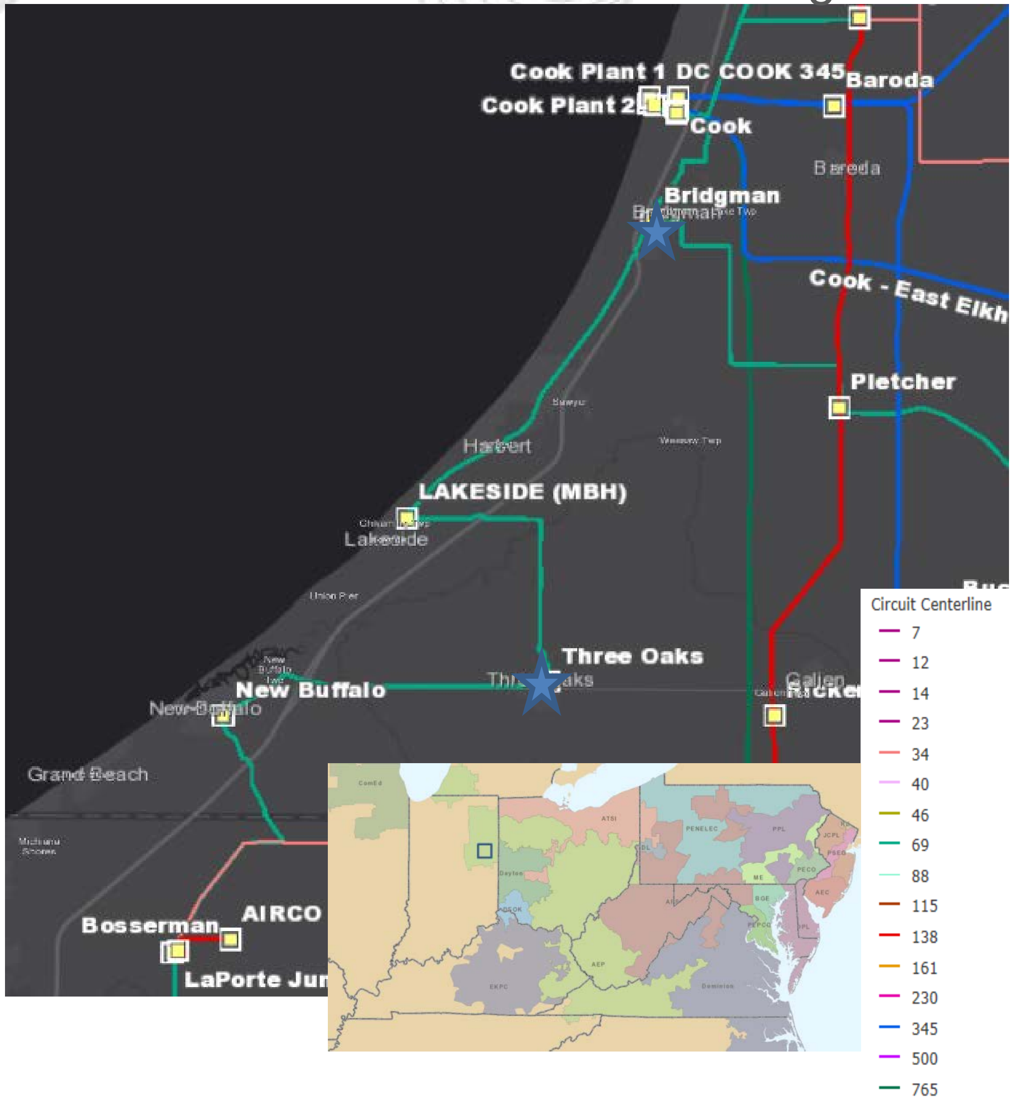
Breakers C, A, & B 69 kV

- 1968 vintage FK Oil breakers
- Fault Operations: C(204), A(48) & B(58) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported

<u>Three Oaks 69 kV Station</u>

Breakers C & B 69 kV

- 1968 vintage FK Oil breakers
- Fault Operations: C(73) & B(63) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported



AEP Transmission Zone M-3 Process Indiana & Michigan

Need Number: AEP-2019-IM009

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

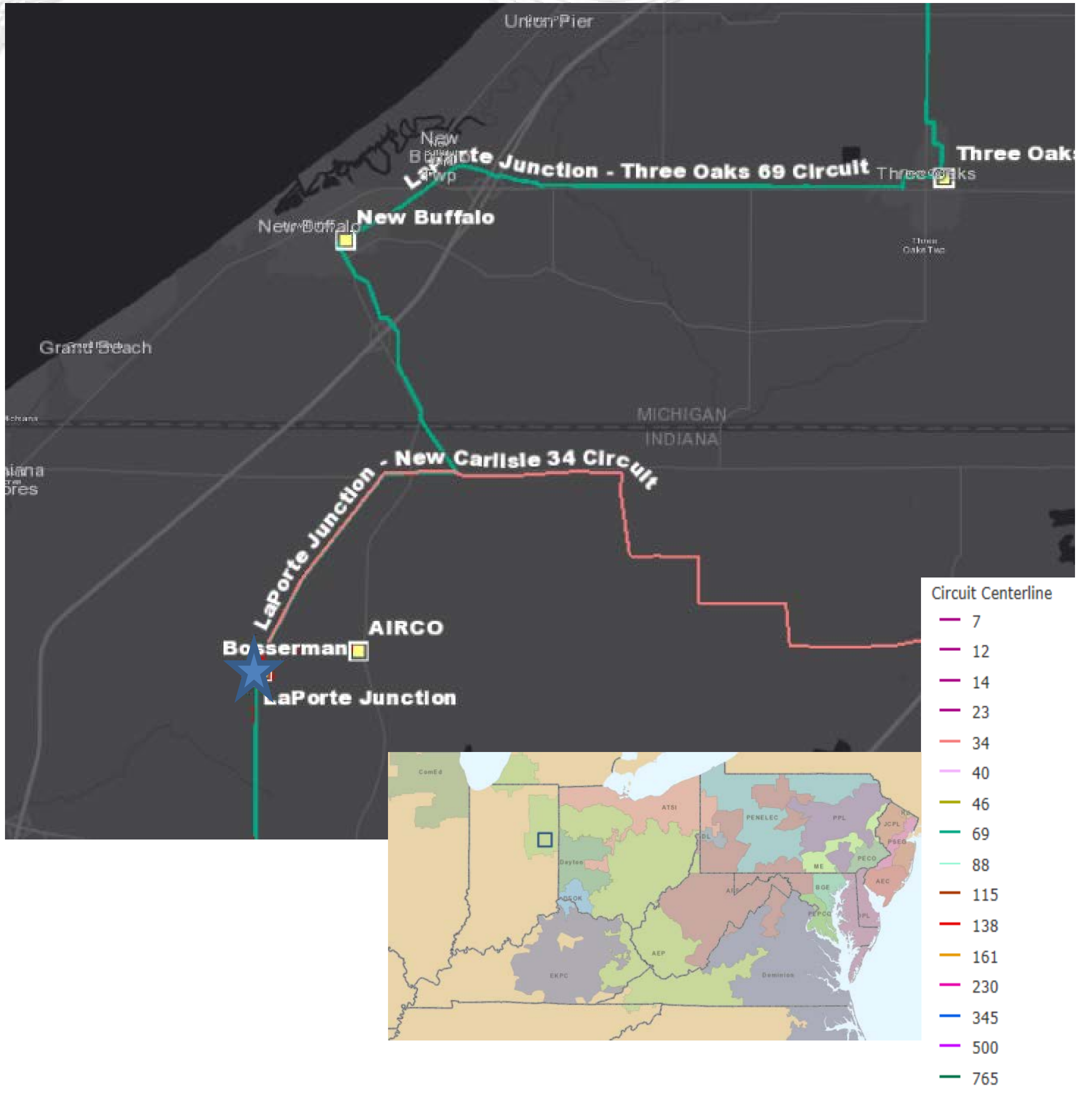
Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>LaPorte 69 kV Station</u>
Breakers B 69 kV

- 1968 vintage FK Oil breakers
- Fault Operations: B(62) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported.

Transformer #1 138/69/34 kV

- 1967 vintage
- Its showing significant signs of deterioration and has high levels of Carbon Dioxide dissolved in the oil.
- Equipment condition concerns include dielectric strength breakdown (winding insulation), short circuit strength breakdown (due to the amount of through fault events), and accessory damage (bushings).



AEP Transmission Zone M-3 Process
Indiana & Michigan

Need Number: AEP-2019-IM009

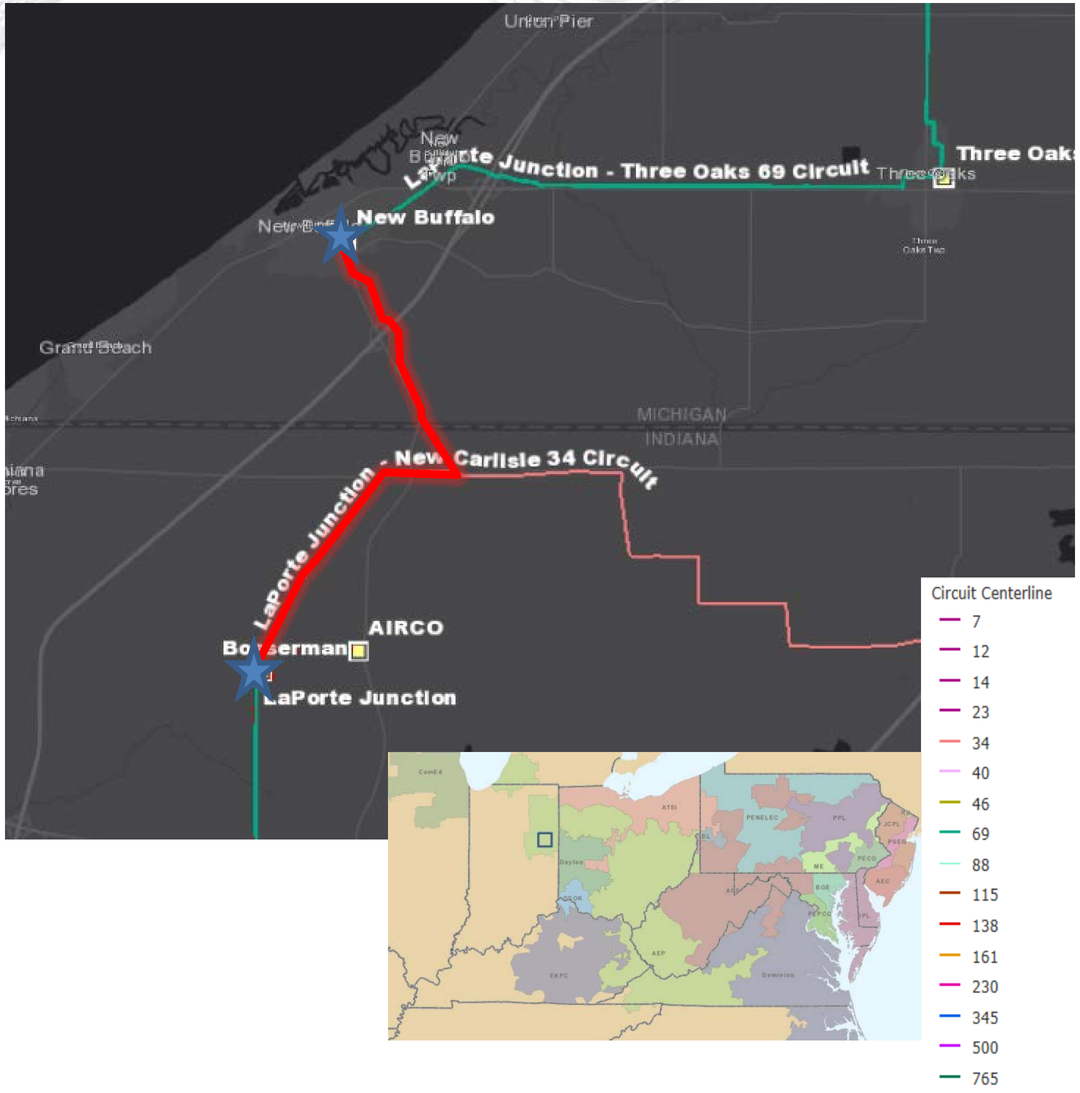
Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Laporte Junction – New Buffalo (IN) 69 kV Line (~4 Miles)</u>

- 1960's vintage wood crossarm construction
- Approximately 78% of the structures have Insect Damage
- There are currently 132 open conditions on this line with majority being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.



AEP Transmission Zone M-3 Process
Dowagiac, Michigan Area

Need Number: AEP-2019-IM010

Process Stage: Needs Meeting 04/23/19

Supplemental Project Driver:
Equipment Condition/Performance & Operational Flexibility

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Colby Station</u>
Breakers A, B, C, D, and E

- 1963-1968 vintage oil breakers
- CB Fault operations: CB A(38), C(67), D(86), E(12) – Recommended(10)
- Breaker B control cabinet has documented corrosion concerns
- Since 2017 breaker D's operation counter hasn't functioned

Currently contains a 3-terminal line within the station.

AEP Transmission Zone M-3 Process
Marion, Indiana

Need Number: AEP-2019-IM011

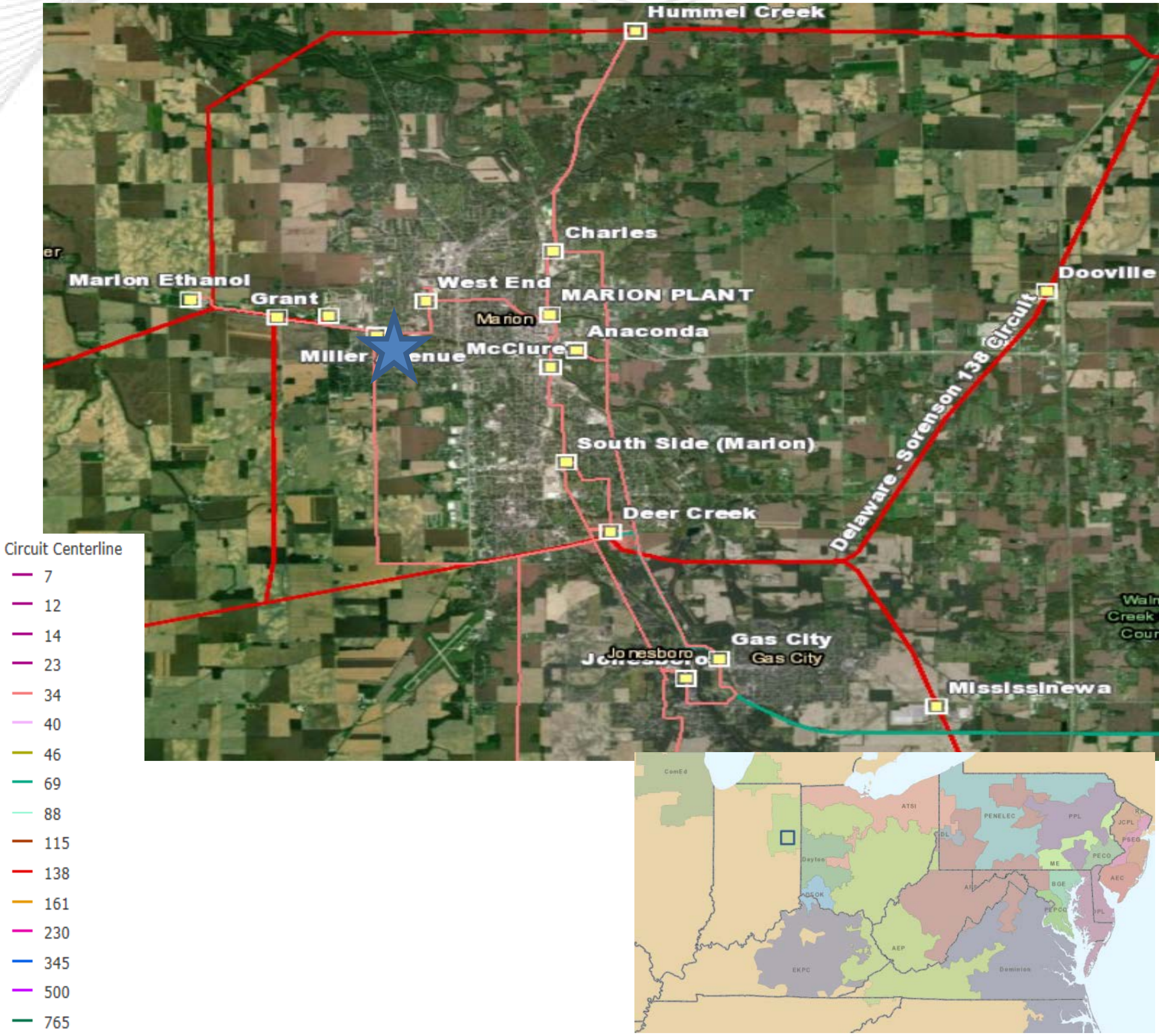
Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Customer Request

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>West End 34.5 kV station</u>

- AEP I&M Distribution is rebuilding and reconfiguring their West End Station to address aging equipment and capacity concerns.



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM012

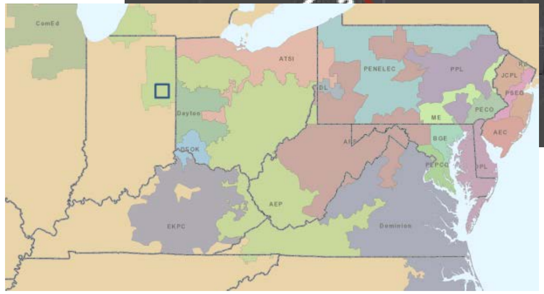
Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Illinois Road 138 kV station</u>
Breakers A & B 69 kV

- 1969 and 1970 vintage Oil breakers
- Fault Operations: A(23) & B(67) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM013

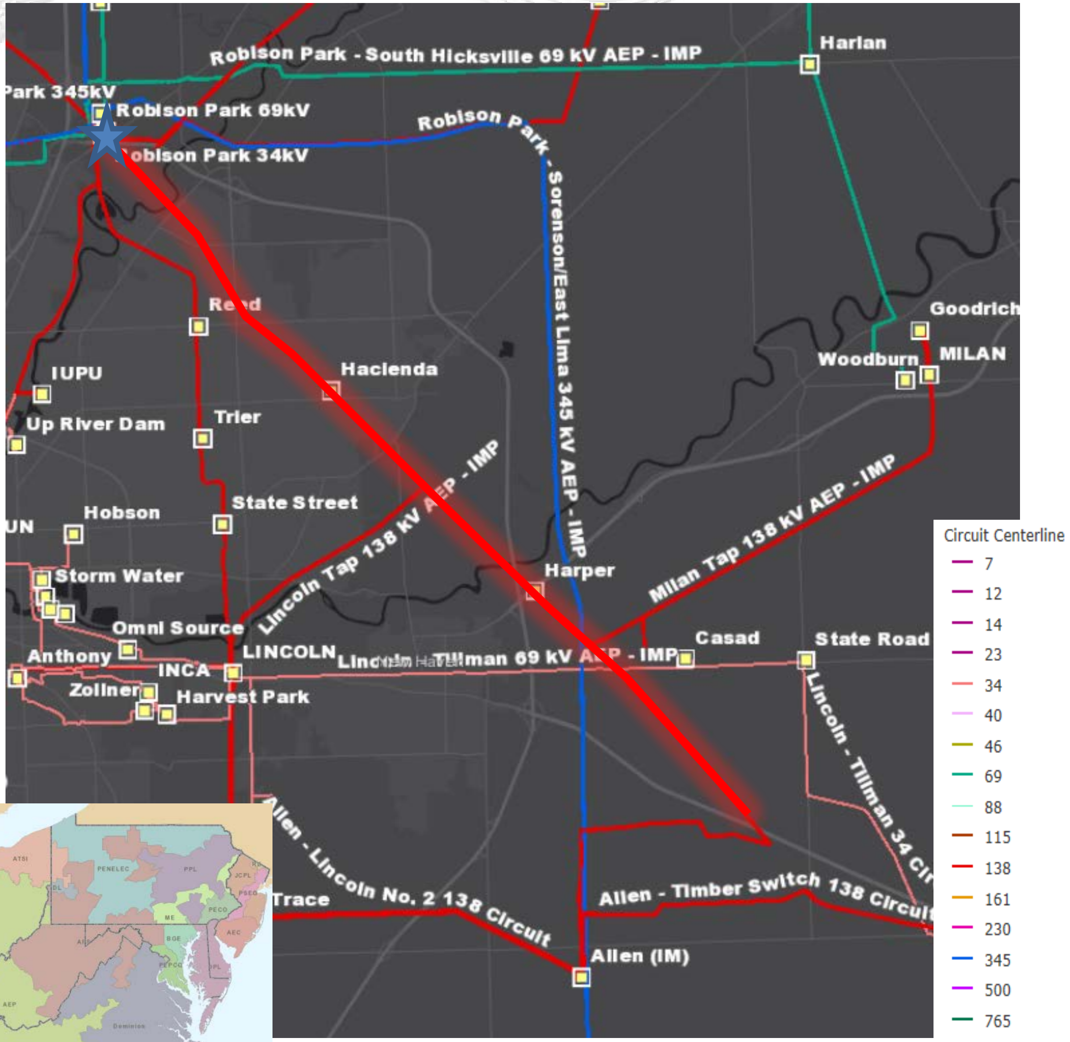
Process Stage: Needs Meeting 04/23/2019

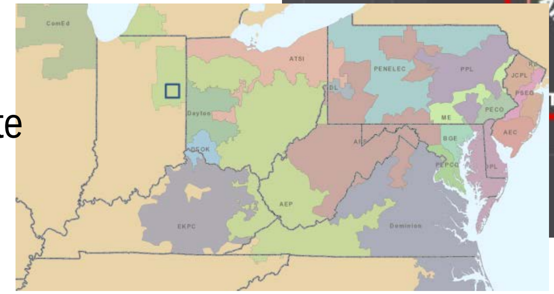
Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Robison Park – Haviland 138 kV Line (~12 Miles)</u>

- 1926 vintage steel lattice line construction
- There are currently 56 open conditions on this line with majority (84%) being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.
- Forced Momentary Outages: 2
- Forced Permanent Outages: 1
- The current line shielding angle on the steel towers is inadequate for current AEP shielding angle requirements.





AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM014

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Robison Park – South Hicksville 69 kV Line (~27 Miles)

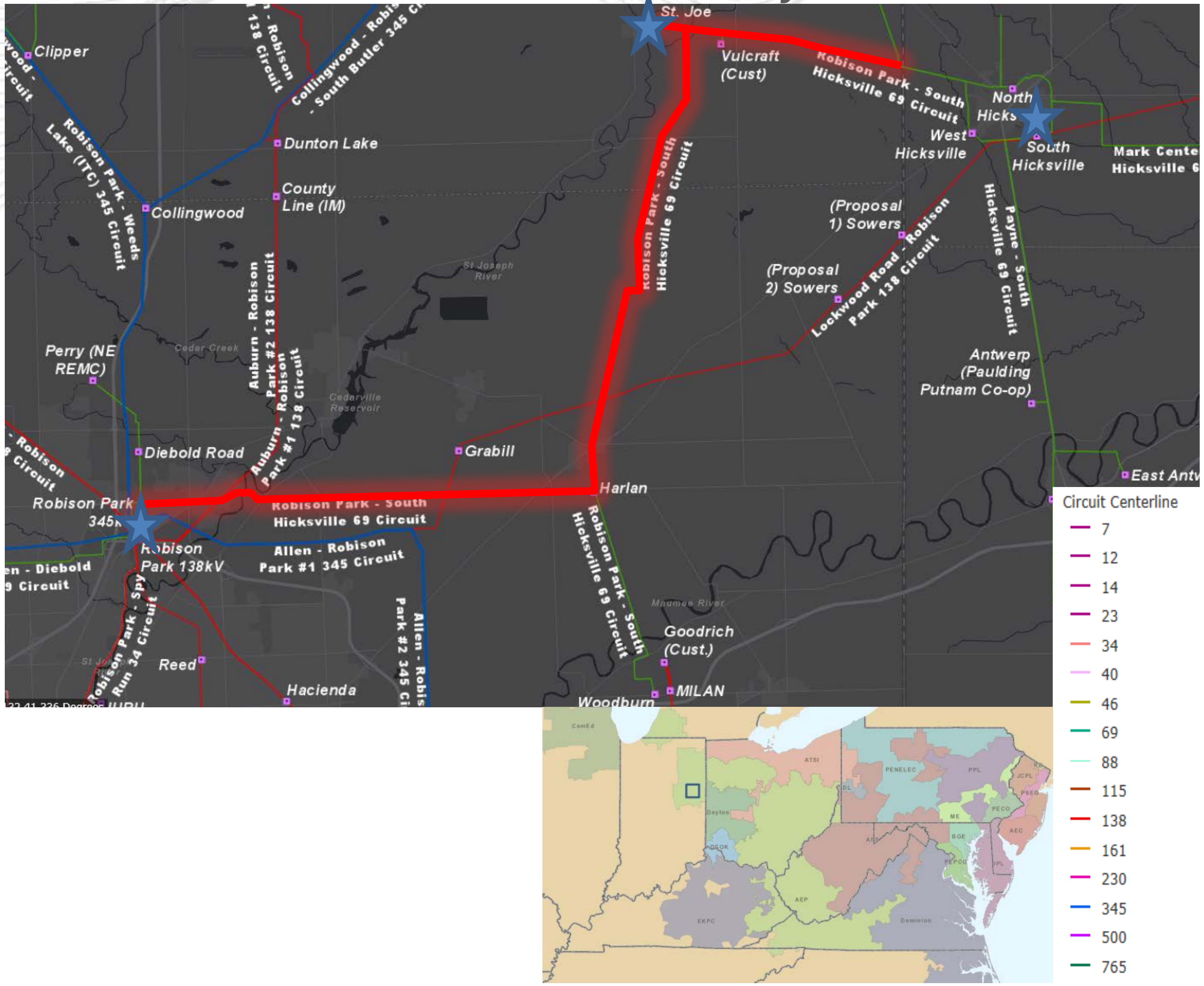
- 1967 vintage wood cross arm construction.
- There are currently 56 open conditions on this line with majority (94%) being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.
- 4/0 ASCR conductor with horizontal post type porcelain insulators.
- CMI: 526,269
- Forced Momentary Outages: 6
- Forced Permanent Outages: 5

St Joe Tap 69 kV Line (~0.6 Miles)

- 1967 vintage wood cross arm construction
- There are currently 3 open conditions on this line. The O&M cost of the line is expected to increase as the age of the line increases.
- St. Joe is radially served out of Robison Park – South Hicksville 69 kV Line and it is susceptible to single event outages.
- It occasional encounter floodwaters of Bear Creek that leave some of the existing poles inaccessible.

St. Joe Tap Switch

- The Switch has accessibility challenges due to St. Joseph River floodwaters.



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM015

Process Stage: Needs Meeting 04/23/2019

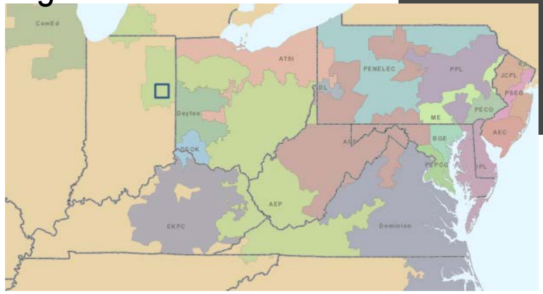
Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
The loads at Bixler and North Kendallville are 20.58 MW and 17.13 MW respectively. Bixler is radially served from a 2.89 mile long 138 kV line. North Kendallville is radially served from a 1.79 mile long 69 kV line.

Kendallville – North Kendallville 69 kV Line (~1.7 Miles)

- 1960's vintage wood pole construction
- There are currently 5 open conditions on this line with majority being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.
- CMI: 1,541,297
- Forced Momentary Outages: 1
- Forced Permanent Outages: 9



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM016

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:

Equipment Condition/Performance/Risk

Specific Assumptions Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

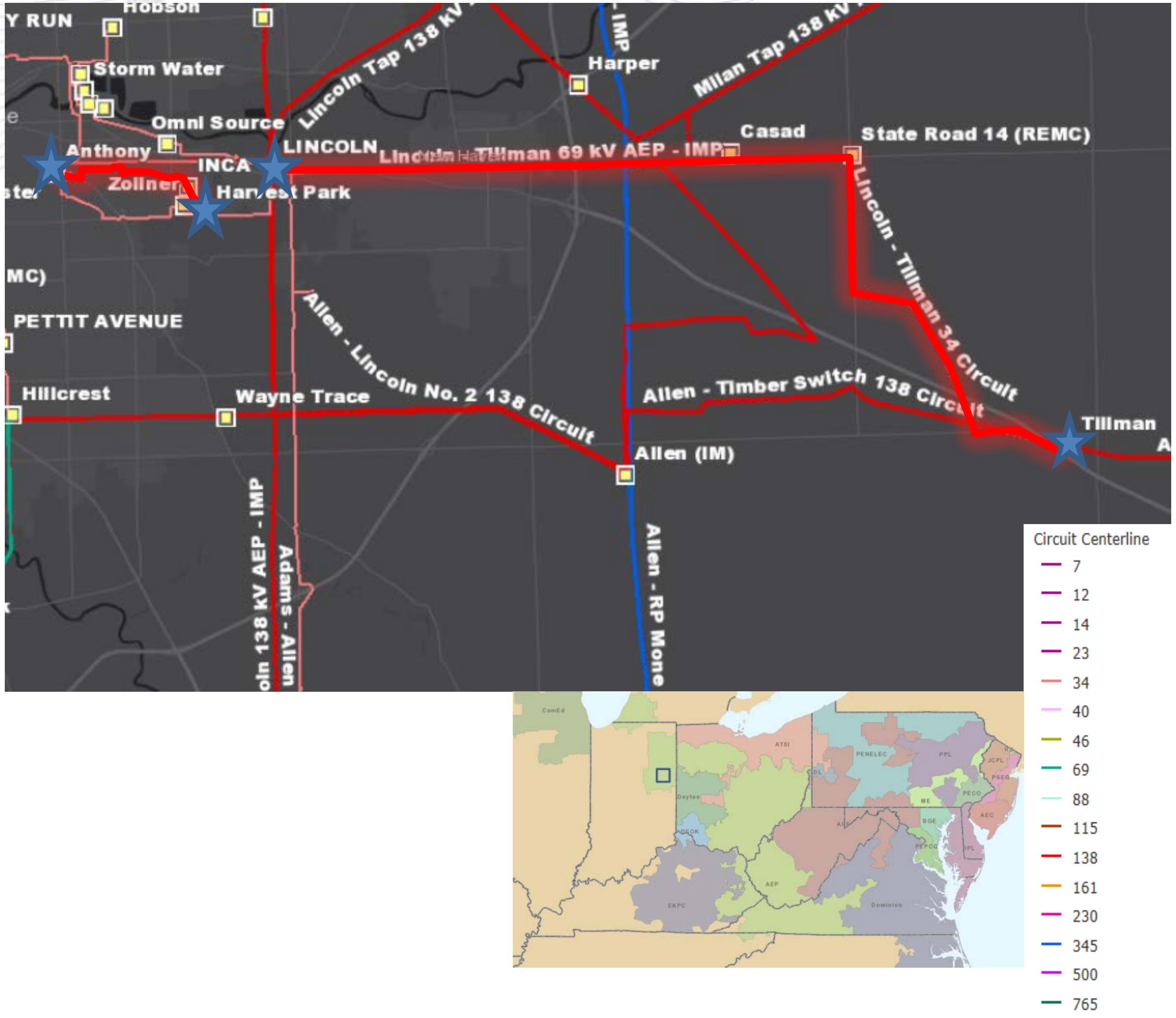
Problem Statement:

<u>Anthony – Harvest Park No.2 34 kV Line (~2.5 Miles)</u>

- 1930's vintage wood crossarm construction
- There are currently 14 open conditions on this line with majority being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.

<u>Lincoln – Tillman 69 kV Line (~13 Miles)</u>

- 1968 vintage wood crossarm construction
- There are currently 24 open conditions on this line with majority being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM016

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

<u>Anthony 34 kV station</u>

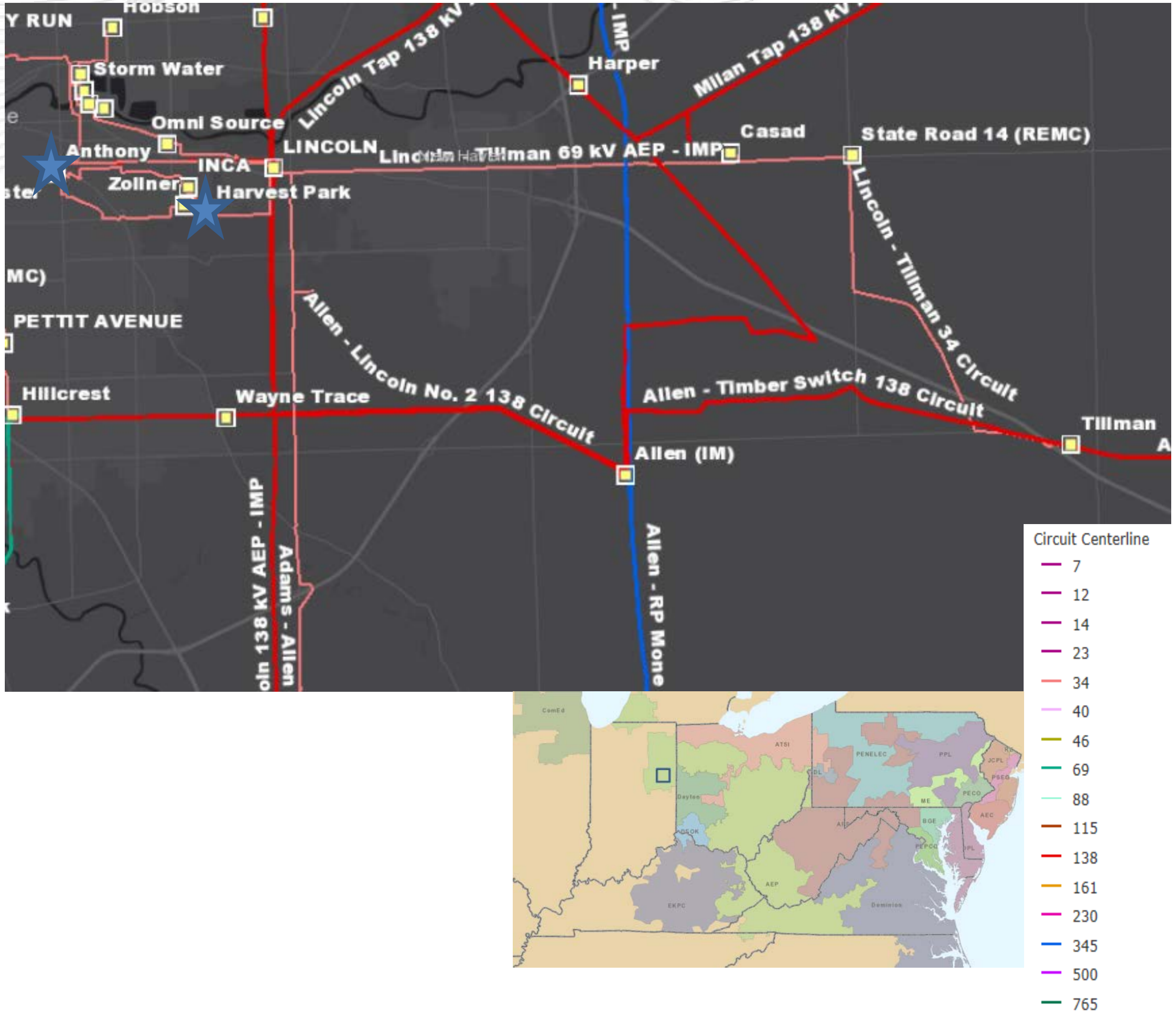
Breakers H, Q, D, C & A 34 kV

- 1970 vintage FK Oil breakers
- Fault Operations: H(21), A(12) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported

<u>Harvest Park 34 kV station</u>

Breakers S, N, A & B 34 kV

- 1962 vintage FK Oil breakers S, N & B
- 1956 vintage FK Oil breakers B
- Fault Operations: A(49) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported



AEP Transmission Zone M-3 Process
Ft. Wayne, Indiana

Need Number: AEP-2019-IM017

Process Stage: Needs Meeting 04/23/2019

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

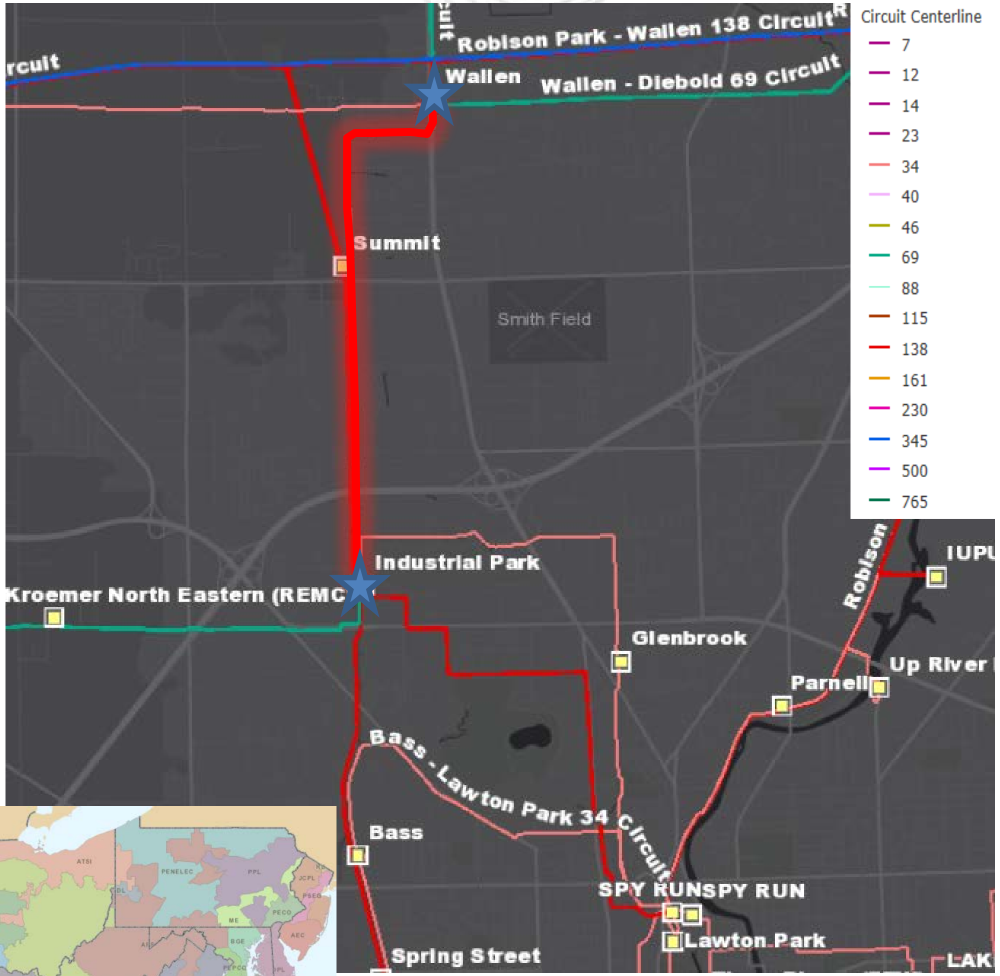
Problem Statement:

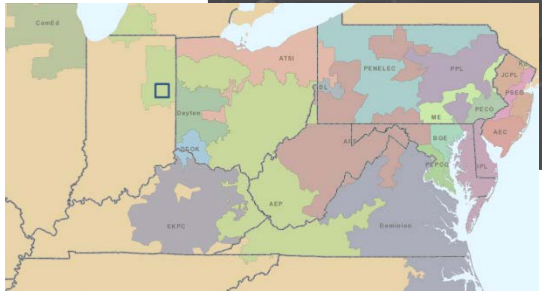
Industrial Park – Wallen 34 kV (~3.3 Miles)

- 1925 vintage steel lattice construction
- There are currently 5 open conditions on this line with majority being structure issues. The O&M cost of the line is expected to increase as the age of the line increases.
- Six wired Copper conductor with copper weld shield wire. Copper conductors become brittle with age and Copper weld conductor has long been obsolete

Industrial Park 138 kV

- Breakers F, D & E 34 kV
  - 1967 vintage Oil breakers
  - Fault Operations: F(18), D(0) & E(14) – Recommended(10)
- Breakers G 69 kV
  - 1967 vintage Oil breakers
  - Fault Operations: G(50) – Recommended(10)
- Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units is difficult or impossible, and these models are no longer vendor supported.
- Multiple wood pole 138 kV transformer lead support structures inside Industrial Park Station.





Solutions

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

AEP Transmission Zone M-3 Process
Hartford City, Indiana Area

Need Number: AEP-2018-IM004

Process Stage: Solution Meeting 4/23/2019

Previously Presented: Needs Meeting 10/26/18

Supplemental Project Driver:

Equipment Condition/Performance/Risk

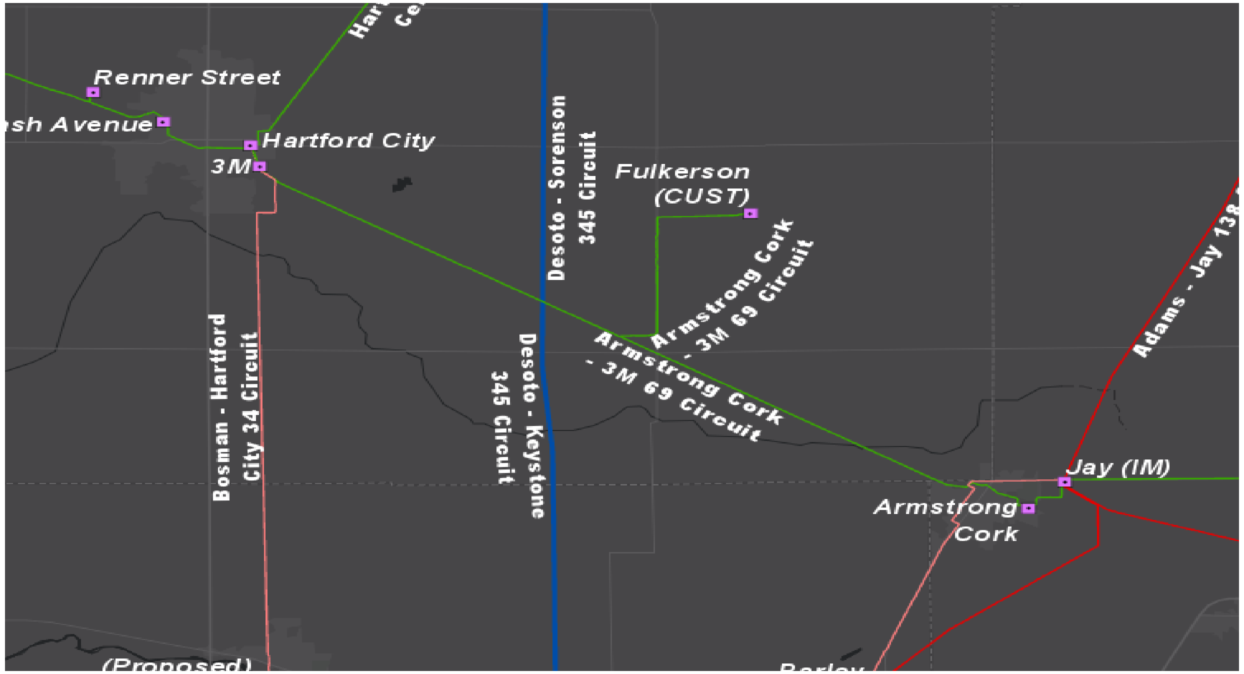
Specific Assumptions Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

<u>3M Station 69 kV Station</u>

- Breaker A
  - 1967 FK oil filled breakers without oil containment.
  - Fault Operations: CB A(23) – Recommended (10)



AEP Transmission Zone M-3 Process
Hartford City, Indiana Area

Need Number: AEP-2018-IM004

Process Stage: Solution Meeting 4/23/2019

Proposed Solution (Supplemental):

3M 69 kV

Transmission will rebuild the full through-path of 3M station in the plot of land directly south of the existing 3M station. This through path includes one 69 kV breaker toward Jay station and a MOAB toward Hartford City station.

Transmission was approached by I&M Distribution with their needs at 3M station after the initial read of the transmission needs. In working with I&M Distribution on the best solution to address both T and D needs at 3M, it was determined the best approach would be to build in the clear at an adjacent site to minimize the outages while addressing both sets of needs.

Alternatives:

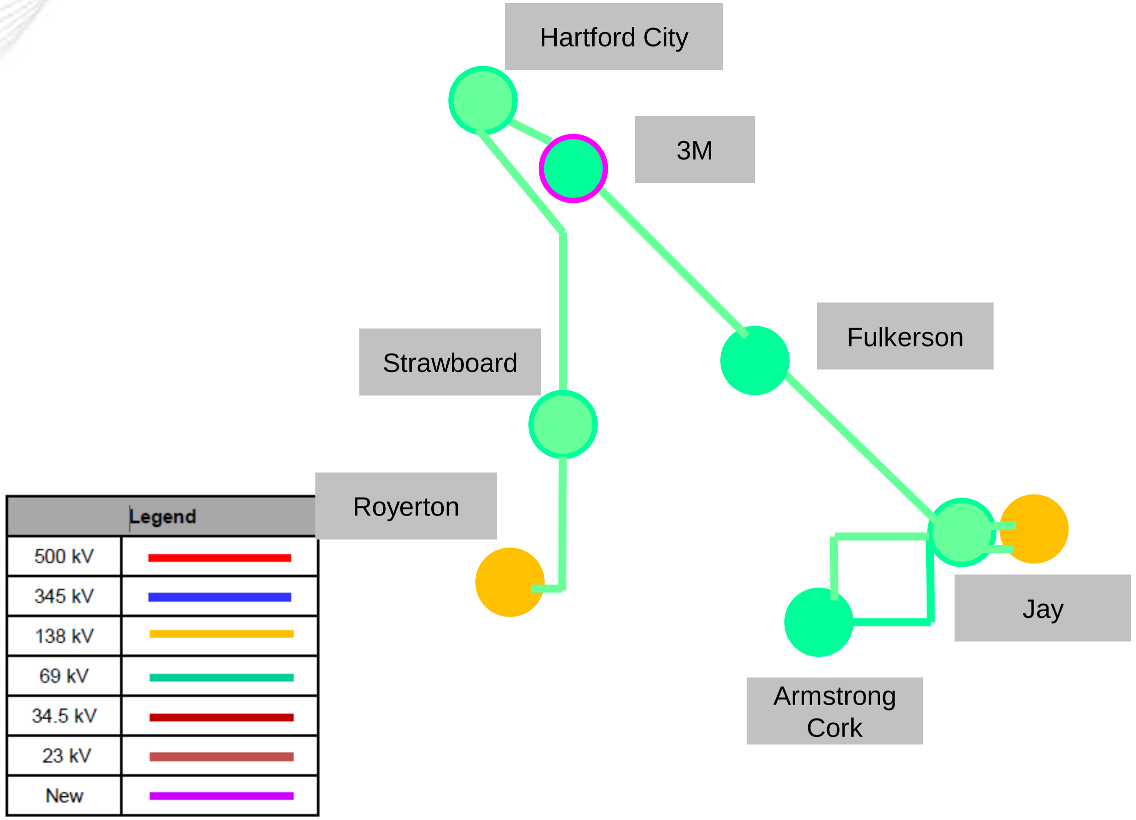
Alternate 1:

Rebuild the station on site. Due to the sensitivity of the customers served by 3M station and their inability to take sustained outages, this was deemed non-viable.

Total Estimated Transmission Cost: $1.35 M

Projected IS Date: 6/1/2022

Project Status: Scoping



AEP Transmission Zone M-3 Process
Tanners Creek, IN

Need Number: AEP-2019-IM003

Process Stage: Solutions Meeting 4/23/2019

Previously Presented: Needs Meeting 2/20/2019

Supplemental Project Driver:
Operational Efficiency & Flexibility

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Tanners Creek 345 kV</u>
- Currently a line fault on the Dearborn circuit causes 5 EHV breakers to open. This is above the AEP max of 4 and must be addressed.
- According to the DEDSTFMRS PJM document, 200 kV+ facilities with 7+ elements are required to be in a complete breaker and a half setup at a minimum. This facility has 9 elements and is currently in an incomplete breaker and a half setup.

AEP Transmission Zone M-3 Process
Tanners Creek, IN

Need Number: AEP-2019-IM003

Process Stage: Solutions Meeting 4/23/2019

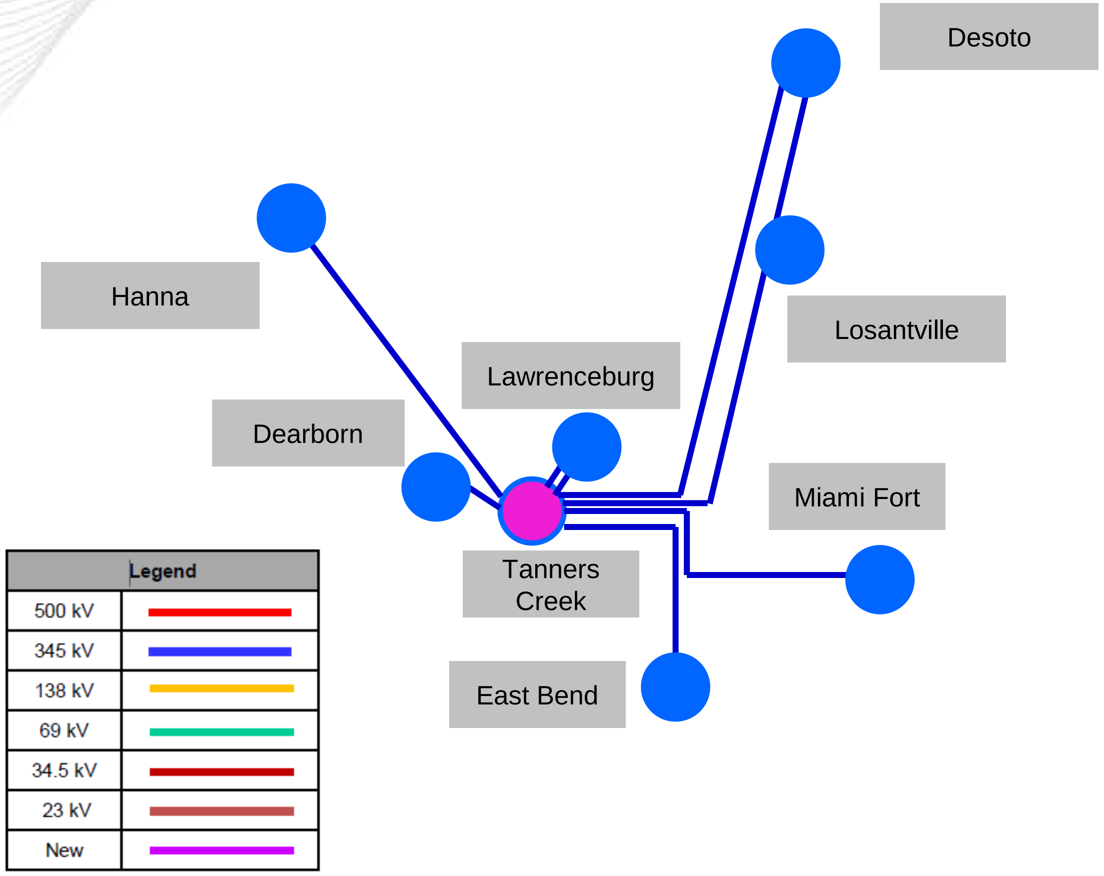
Proposed Solution:
Install 2 new 345 kV breakers and move the existing M2 breaker into the new N string. Terminate the Dearborn line and the transformer into the new N string. Install a new 345 kV breaker "T" to complete the T string.

Alternatives:
Reterminate the 345/138 kV transformer and 345 kV Dearborn line into existing breaker spots. Due to the way the station is laid out, this would require reconfiguring multiple 345 kV lines and would cost more.

Total Estimated Transmission Cost: $5.93 M

Projected IS Date: 6/1/2021

Project Status: Scoping



AEP Transmission Zone M-3 Process
Greentown, IN

Need Number: AEP-2019-IM004

Process Stage: Solutions Meeting 04/23/2019

Previously Presented: Needs Meeting 02/20/2019

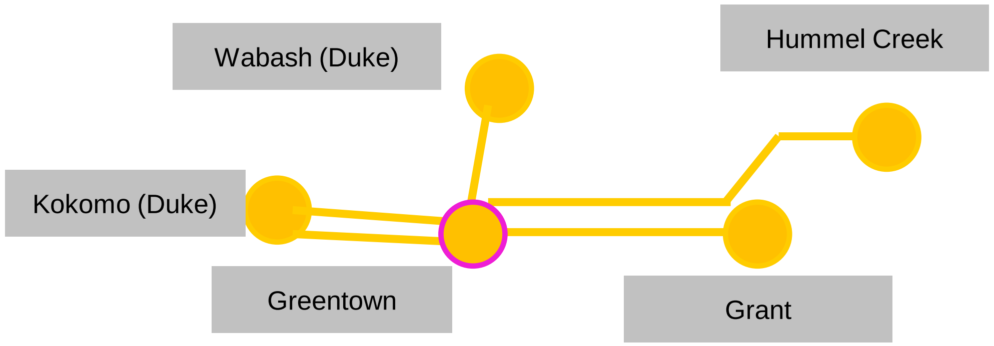
Supplemental Project Driver:
Operational Efficiency & Flexibility

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- Greentown
  - According to the DEDSTFMRS PJM document, BES facilities with 7+ elements are recommended to be in a complete breaker and a half setup at a minimum. This facility has 7 elements and is currently in an incomplete breaker and a half setup.

AEP Transmission Zone M-3 Process
Greentown, IN



Need Number: AEP-2019-IM004

Proposed Solution:

Greentown 765/230/138 kV station:

Install two 138 kV breakers to terminate the 765/138 kV Transformer into a breaker and a half string. This work will be done in conjunction with the significant MISO work being planned at this station,

Alternatives:

No cost effective viable alternates were identified.

Total Estimated Transmission Cost: $2.7 M

Projected IS Date: 02/15/2023

Project Status: Scoping

Legend	
500 kV	red
345 kV	blue
138 kV	yellow
69 kV	green
34.5 kV	dark red
23 kV	light red
New	magenta

AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010

Process Stage: Solution Meeting 4/23/2019

Previously Presented: Needs Meeting 10/26/18

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
<u>Jonesboro – South Summitville</u>

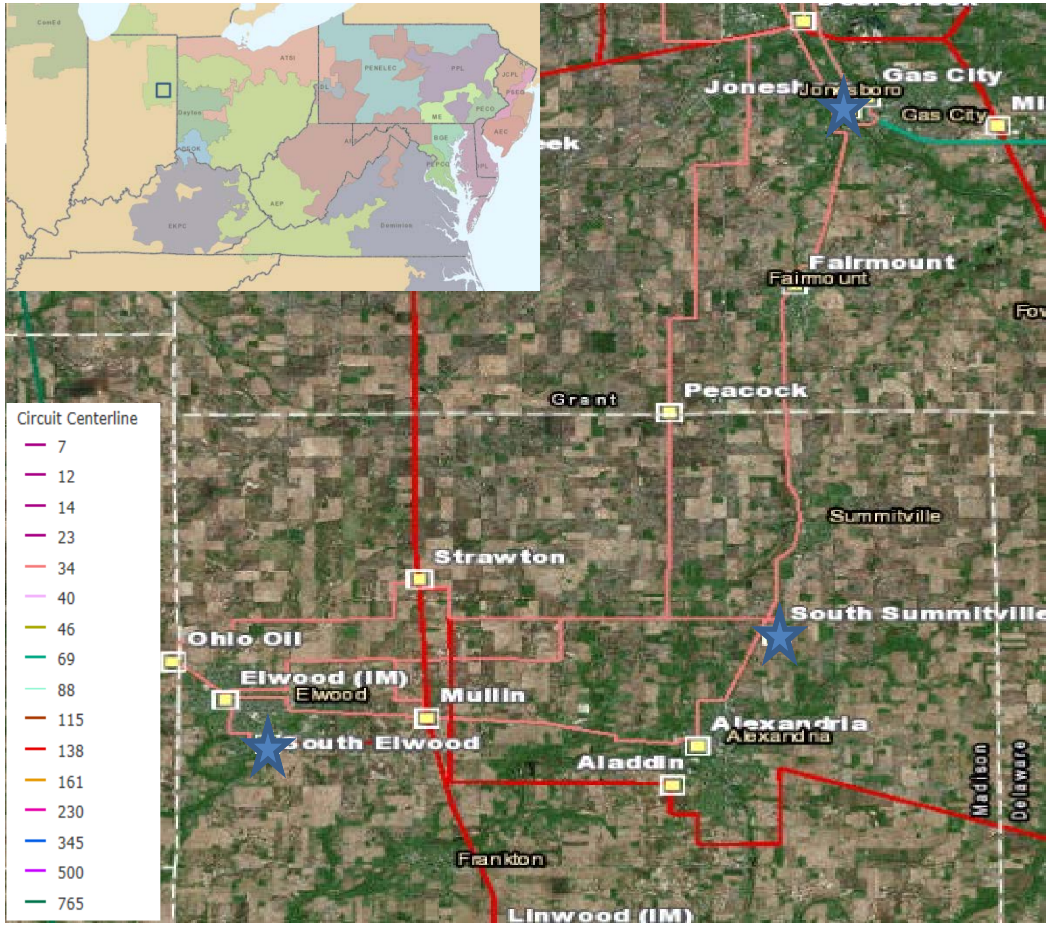
- 1930's wood crossarm construction
- #2 copper
- Over the past 10 years this line has had 128 structures require active maintenance with the majority being wood rot. This trend is expected to increase as the line ages.
- 68 structures currently have an open condition

<u>South Elwood</u>
Breaker "C"

- 1951 FK oil type with no oil containment
- Fault Operations: CB C(19) – Recommended (10)

Transformer 1 – 1955 vintage

- Type O Westinghouse bushings
- Increasing power factor
- Increasing Carbon Monoxide
- Failed internal heater circuit.
- Physically obstructs other station assets.



AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010

Process Stage: Solution Meeting 4/23/2019

Process Chronology: Needs Meeting 10/26/18

Supplemental Project Driver:
Equipment Condition/Performance/Risk

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement (continued):

<u>Fairmount</u>

Breakers “A” and “B”

- Fault Operations: A(75) B(99) – Recommended(10)

Transformer 1 – 1972 vintage

- High Carbon Dioxide level
- Dielectric issues

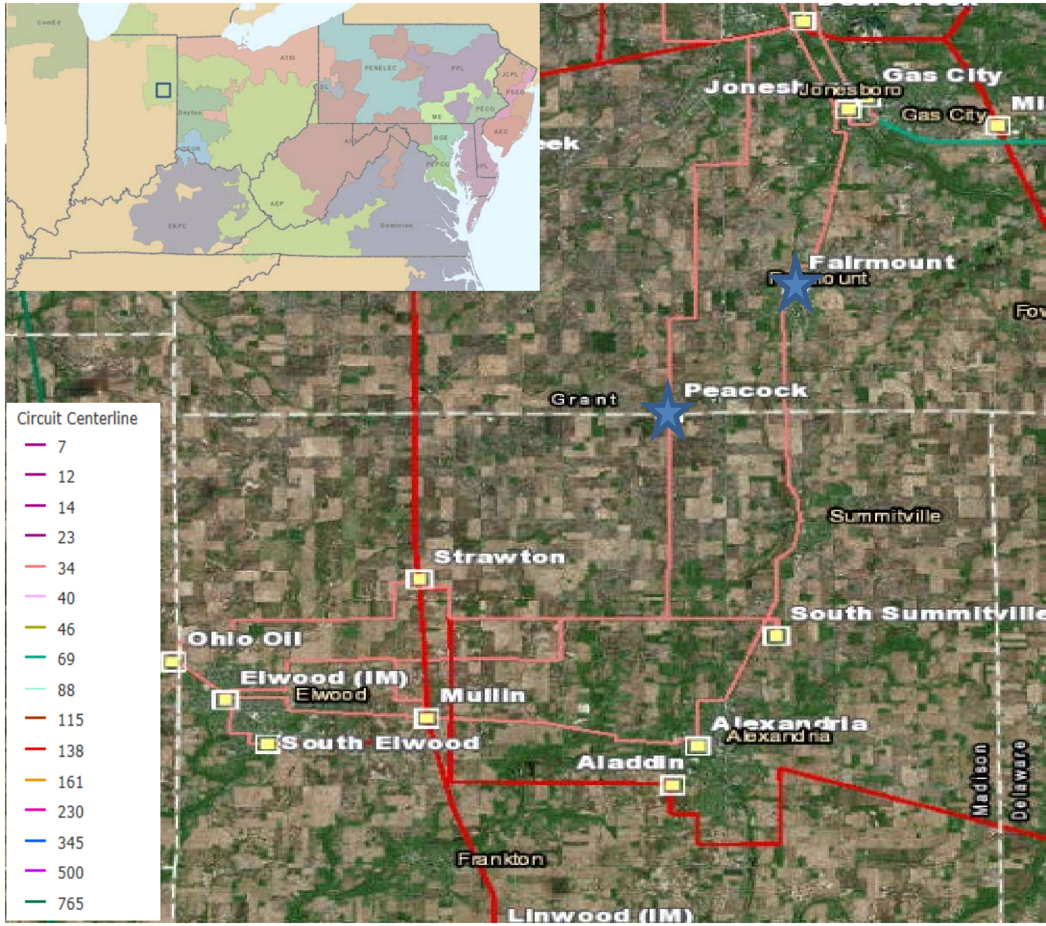
<u>Peacock</u>

Breaker “A”

- 1969 PR Oil breaker without containment
- Fault Operations: A(154) – Recommended(10)

Transformer 1 – 1951 Vintage

- High levels of Ethane, Methane, and CO2.
- Increasing Insulation power factor.



AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010

Process Stage: Solution Meeting 4/23/2019

Process Chronology: Needs Meeting 10/26/18

Supplemental Project Driver:

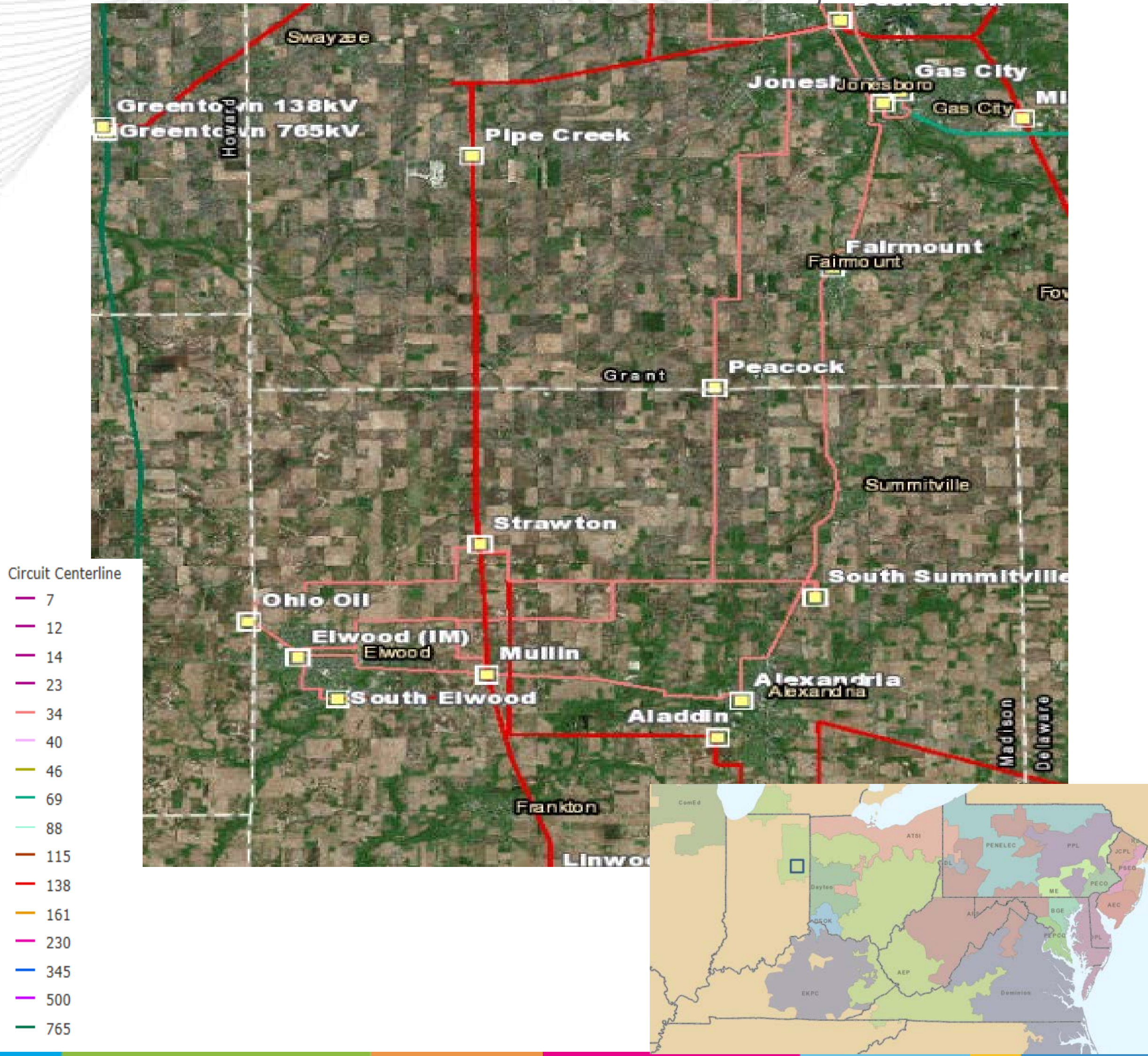
Customer Service/Operational Flexibility & Efficiency

Specific Assumptions Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

- Both AEP Transmission and AEP distribution have received multiple requests for economic development in this area.
- The current system would require significant rework in order to facilitate these requests, and the timeline for those fixes are not conducive to customer timelines.
- The 34.5 kV system is subject to “Drop and Pick” operating procedure. This operating procedure has been an issue for I&M Distribution operations as it results in less reliable service for the customer and causes outages that could otherwise be avoided.



AEP Transmission Zone M-3 Process
Marion, Indiana

Need Number: AEP-2018-IM017

Process Stage: Solution Meeting 4/23/2019

Process Chronology: Needs Meeting 1/11/2019

Supplemental Project Driver:

Equipment Condition/Performance/Risk

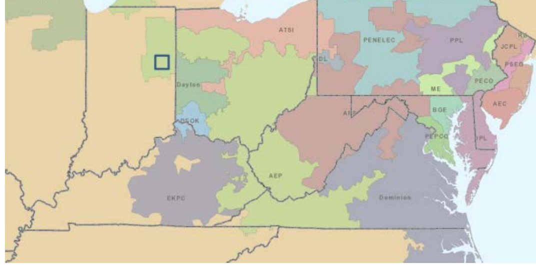
Specific Assumptions Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Deer Creek 34.5 kV

- Breakers “U”
  - 1950 vintage FK oil breakers without containment
  - Fault Operations: CB U(38)– Recommended(10)



AEP Transmission Zone M-3 Process
Alexandria, Indiana

Need Number: AEP-2019-IM005

Process Stage: Solution Meeting 4/23/2019

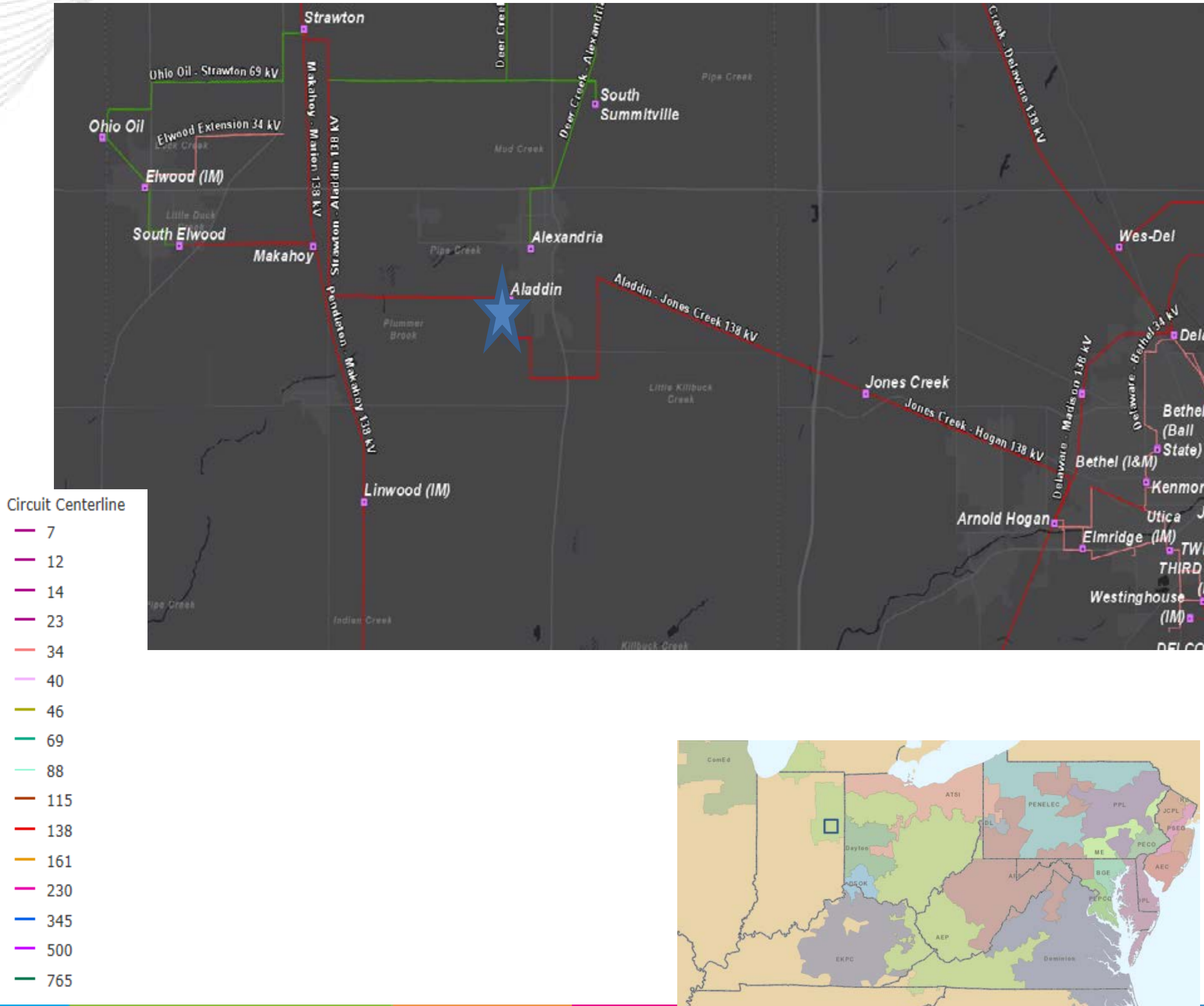
Process Chronology: Needs Meeting 02/20/2019

Supplemental Project Driver:
Operational Flexibility and Efficiency

Specific Assumptions Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
Associated Needs: AEP-2018-IM010
Strawton – Arnold Hogan 138 kV

- This line currently has 4 MOABS in series (2 at Aladdin and 2 at Jones Creek) which is above AEP's max of 3.



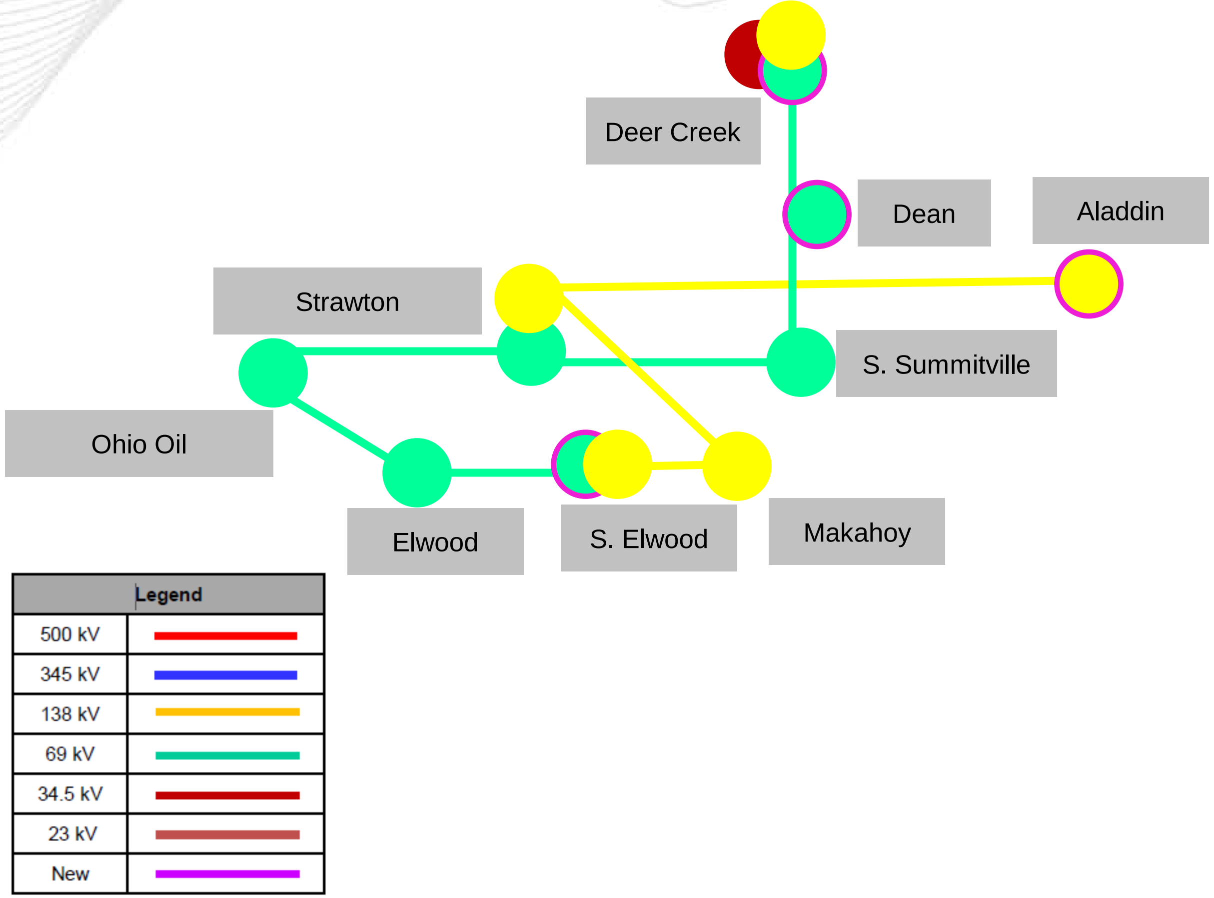
AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010, AEP-2018-IM017, AEP-2019-IM005

Process Stage: Solutions Meeting 4/23/2019

Proposed Solution:

<u>Jonesboro – South Summitville 34.5 kV line:</u>
Retire the ~10.5 mile South Summitville – Jonesboro 34.5 kV line.
<u>Jonesboro 34.5 kV station:</u>
Retire Jonesboro station
<u>Dean 69 kV station & Fairmount/Peacock 34.5 kV stations:</u>
Install the new 69 kV Dean station with a single bus tie breaker to take replace the 34.5 Fairmount and Peacock stations
<u>South Elwood 138/34.5 kV station:</u>
Replace the 138/34.5 kV XFR 1 and the existing 34.5 kV breaker with a 138/69 kV XFR and a 69 kV rated breaker
<u>Deer Creek 138/69/34.5 kV station:</u>
Install a 3 breaker 69 kV ring bus In the clear to enable the connection of the now 69 kV rated South Summitville line. Add a 138 kV breaker to the high side of XFR 1 to replace the moab.
<u>Aladdin 138 kV station:</u>
Install a 138 kV bus tie breaker at Aladdin station to breaker up the 4 MOABS in series



AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010, AEP-2018-IM017, AEP-2019-IM005

Process Stage: Solutions Meeting 4/23/2019

Proposed Solution:

Elwood 34.5 kV station

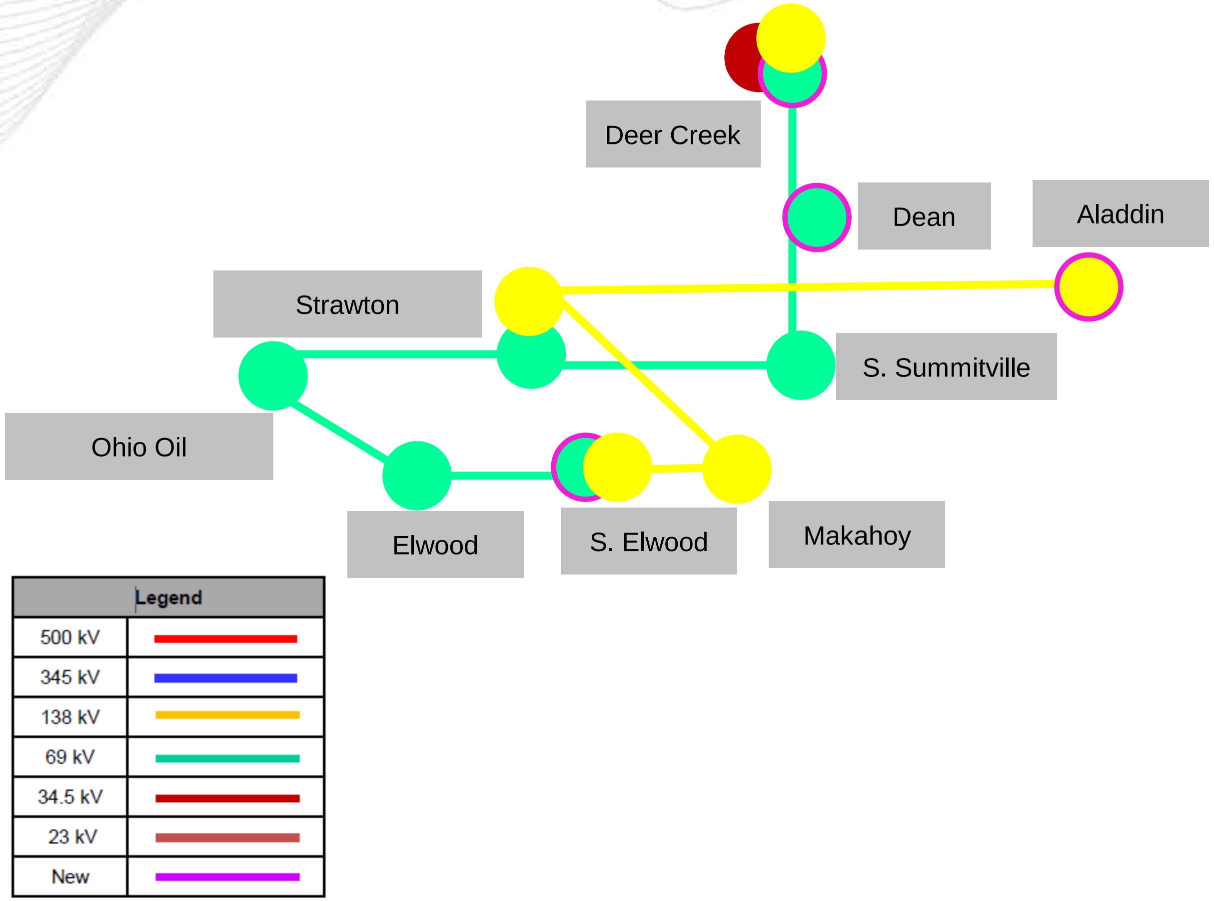
Rebuild Elwood in the clear as an in and out station with a bus tie breaker.

Strawton Area work

Energize Ohio Oil, South Summitville, Strawton and the lines connecting them to 69 kV. These stations and lines are already built to this standard.

Alternatives:

Re-use both breakers at Elwood and keep the original configuration. While this configuration protects Elwood's load from line faults, it doesn't allow for AEP to take bus outages for maintenance. With the removal of the Cap Bank, full line protection becomes no longer needed. Changing the configuration to a single breaker improves distribution's reliability, reduces the station footprint and saves money.



AEP Transmission Zone M-3 Process
Elwood, Indiana

Need Number: AEP-2018-IM010, AEP-2018-IM017, AEP-2019-IM005

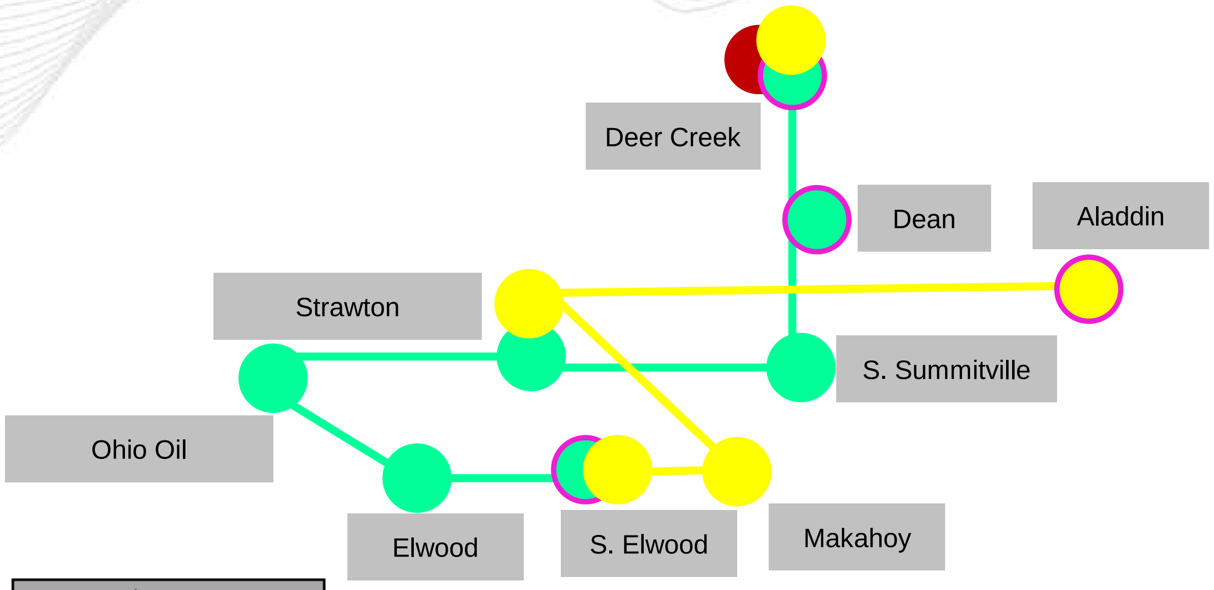
Alternatives:

Re-use 69 kV breaker "J" at Deer Creek station in the 69 kV ring bus. Breaker "J" is still in good shape. But in order to minimize outages, it was decided that AEP would use brand new breakers for the 69 kV voltage class and will plan to re-use J when addressing the remaining 34.5 kV needs at this station.

Total Estimated Transmission Cost: $17.4M

Projected IS Date: 10/1/2021

Project Status: Scoping



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Appendix

High level M-3 Meeting Schedule

Assumptions

Activity	Timing
Posting of TO Assumptions Meeting information	20 days before Assumptions Meeting
Stakeholder comments	10 days after Assumptions Meeting

Needs

Activity	Timing
TOs and Stakeholders Post Needs Meeting slides	10 days before Needs Meeting
Stakeholder comments	10 days after Needs Meeting

Solutions

Activity	Timing
TOs and Stakeholders Post Solutions Meeting slides	10 days before Solutions Meeting
Stakeholder comments	10 days after Solutions Meeting

Submission of Supplemental Projects & Local Plan

Activity	Timing
Do No Harm (DNH) analysis for selected solution	Prior to posting selected solution
Post selected solution(s)	Following completion of DNH analysis
Stakeholder comments	10 days prior to Local Plan Submission for integration into RTEP
Local Plan submitted to PJM for integration into RTEP	Following review and consideration of comments received after posting of selected solutions

Revision History

4/12/2019 – V1 – Original version posted to pjm.com

4/16/2019 – V2 – Slide #35: Corrected the solution meeting date
Slide #36: Add “Process Stage”

4/16/2019 – V3 – Slides #41 -45: Change Solution meeting date from 4/23/2018 to 4/23/2019
Slide #14, 20: Corrected Need meeting date

4/16/2019 – V4 – Slides #23: Add “open conditions along the 23 mile long line.”

4/26/2019 – V5 – Slides #21: Revise Problem Statement
– Slides #36: Add detailed explanations under in Proposed Solution

TRANSMISSION AGREEMENT

By and among

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

KINGSPORT POWER COMPANY

OHIO POWER COMPANY

WHEELING POWER COMPANY

and with

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

DATED APRIL 1984, AS AMENDED

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ARTICLE 4 - AGENT'S RESPONSIBILITIES. 6

ARTICLE 5 - SETTLEMENTS. 6

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ARTICLE 7 - Allocation Principles 8

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0.1 THIS AGREEMENT, made and entered into as of the 1st day of April, 1984, and as subsequently amended, by and among APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, COLUMBUS AND SOUTHERN POWER COMPANY (Columbus Company), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (Indiana Company), an Indiana corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, KINGSPORT POWER COMPANY (Tennessee Company), a Tennessee corporation, and WHEELING POWER COMPANY (Wheeling Company), a West Virginia corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power SYSTEM (AEP System), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated companies.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) Appalachian Company in Virginia, West Virginia, and Tennessee (ii) Columbus Company in Ohio, (iii) Indiana Company in Indiana and Michigan, (iv) Kentucky Company in Kentucky, (v) Tennessee Company in Tennessee, (vi) Ohio Company in Ohio and West Virginia, and (vii) Wheeling Company in West Virginia; and

0.3 WHEREAS, certain of the Members have entered into an interconnection agreement, dated July 6, 1951, with modification thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated operation of their electric power supply facilities; and

0.4 WHEREAS, The Members' electric facilities are now and for many years have been interconnected through their respective transmission facilities at a number of points, forming an integrated transmission network; and

0.5 WHEREAS, the Members have achieved benefits through the coordinated planning and development of a fully integrated Transmission System; and

0.6 WHEREAS, the members believe that an agreement which provides for the equitable sharing among the Members of the costs incurred by the Members in connection with the ownership, operation, and maintenance of their respective portions of the Transmission System would enhance equity among the Members for the continued development of a reliable and economic Transmission System; and

0.7 WHEREAS, effective October 1, 2004 the Members joined the PJM Interconnection, LLC ("PJM"), and placed their respective transmission facilities under the functional control of PJM, a regional transmission operator or "RTO"; and

0.8 WHEREAS, PJM provides transmission service, pursuant to the PJM Open Access Transmission Tariff ("OATT"), to the Members and others who require transmission service over the Transmission System; and

0.9 WHEREAS, the Members believe that benefits and advantages could be best realized if this Agreement were administered by a single clearing agent; and

0.10 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.11 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto hereby agree as follows:

ARTICLE 1

DESCRIPTION OF TRANSMISSION SYSTEM

1.1 The Transmission System covered by this Agreement shall include all the transmission facilities, from time to time, owned by the Members that are included in the costs of service used to determine rates for transmission service under the PJM OATT, or successor open access transmission tariff.

ARTICLE 2

OPERATION

2.1 Each member shall maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner.

ARTICLE 3

TRANSMISSION COMMITTEE

3.1 The Members shall appoint representatives to serve on a Transmission Committee. Such representatives shall have authority to act for the Members in the administration of all matters pertaining to this Agreement.

3.2 Each Member shall designate in writing, delivered to the other Members and Agent, the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said Committee and the person or persons who may serve as alternate whenever such representative is unavailable to act. Such person designated by Agent shall act as chairman of the Transmissions Committee and shall be known as the "Transmission Manager".

ARTICLE 4

AGENTS RESPONSIBILITIES

4.1 For the purpose of carrying out the provisions of this Agreement the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

4.11 To arrange for and conduct such meetings of the Transmission Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this Agreement.

4.12 To carry out settlements under this Agreement. Settlements by the Members shall be made for each calendar month through General Ledger accounts (hereby designated and hereinafter called the "TRANSMISSION ACCOUNTS") to be administered by Agent. For the purposes of This Agreement, Transmission Accounts shall be consistent with the accounts listed in the FERC Uniform System of Accounts, and shall include such accounts and sub-accounts as are necessary and proper, directed by the Transmission Committee, and consistent with applicable regulatory requirements.

ARTICLE 5

SETTLEMENTS

5.1 As provided in this Article, following the end of each month, the Members shall effect settlements through the TRANSMISSION ACCOUNTS. Generally, Settlements hereunder will involve the allocation among the Members of transmission-related costs and revenues as incurred and accrued under the PJM OATT, or successor open access transmission tariff, and the recording of same in the Transmission Accounts of the Members, as specified in Appendix I consistent with the Settlement Agreement approved in FERC Docket No. ER09-1279-000.

5.2 All amounts to be allocated among the Members hereunder shall, to the extent practicable, be included in Settlements for the month in which such cost or revenue is realized or accrued. If necessary in order to implement such timely Settlement, the Agent shall be authorized to effect Settlements on an estimated basis and make such adjustment as is needed in subsequent Settlements that will conform the Settlements to the terms of this Agreement.

5.3 For such time as Member Tennessee Company and/or Wheeling Company (Buyer) purchase power from Members Appalachian Company and Ohio Company (Seller), respectively, under agreements that provide for transmission service and related charges to Buyer from Seller (Purchased Power Agreements or "PPAs"), Seller will be allocated or assigned the costs as described on Appendix I, numbers seven (7) through fifteen (15), that would otherwise have been allocated or assigned to Buyer under this Agreement. The total amount of such allocated or assigned costs will be passed through to Buyer by Seller as the transmission service and related charges provided for in their PPAs. Such transmission and related costs will be the only transmission charges passed through to Buyer under any such PPA. When any such PPA expires or is otherwise modified or superseded, the provisions of the PPA that provide for transmission service and related charges to Buyer from Seller will be discontinued and Tennessee Company and/or Wheeling Company will receive directly, by allocation or direct assignment, the transmission and related costs pursuant to this agreement, as described on Appendix I, numbers seven (7) through fifteen (15). At such time, Seller shall no longer be allocated or assigned costs which are properly allocable or assignable to Buyer under this Agreement. Further, from the effective date of this Agreement as modified in FERC Docket No. ER09-1279, all the Members, including Tennessee Company and Wheeling Company, will receive direct allocation of revenues as provided herein and described on Appendix I, numbers one (1) though six (6).

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of Settlements calculated pursuant to this Agreement (such as sales, excise or similar taxes), such tax expense incurred by such Member that would not have been incurred were the Settlements hereunder not being made, such Member shall be entitled, to the extent permitted by the applicable regulatory authority(ies) to include such tax in its transmission revenue requirement under the PJM or successor OATT when transmission revenue requirements of the Members are next updated, and thereby receive an appropriate level of reimbursement (through cost sharing) for such additional taxes by Members and others receiving service from the Transmission System.

ARTICLE 7

Allocation Principles

7.1 All items of cost and revenue included in Settlements hereunder shall be related to the provision of or receipt of transmission service or a related ("ancillary") service by one or more Members. The allocation methods used to share such costs and revenues, as specified in Appendix I, shall be made pursuant to direction by the Transmission Committee.

7.2 The Transmission Committee may at any time during the Term of This Agreement, upon the recommendation of the Agent or any Member, review any item of cost or revenue, in order to determine whether such item is transmission-related, and whether it should be included in Settlements hereunder. Further, whenever the Transmission Committee determines that any change is needed in Appendix I to add or delete any item of cost or revenue, or to change the allocation or accounting basis of any item, the Transmission Committee shall authorize and direct the Agent to effect such change in Appendix I and in monthly Settlements among the Members and to make any filing with the applicable regulatory authority(ies) to implement such change. pursuant to the PJM OATT or any successor open access transmission tariff.

ARTICLE 8

MODIFICATION

8.1 Any Member, or the Agent, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of the month following authorization of such reconsideration by appropriate regulatory authority.

ARTICLE 9

EFFECTIVE DATE AND TERM OF THIS AGREEMENT

9.1 This Agreement shall become effective and shall become a binding obligation of the Parties on the date specified in an Order in such proceeding as this Agreement shall have been filed with, and accepted for filing by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act as a rate schedule.

9.2 This Agreement shall continue in effect for four years from the effective date of the final order in Docket No. ER09-1279-000 for successive periods of one year each until terminated as provided under subsection 9.3 below.

9.3 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this Agreement at the expiration of such notice period.

ARTICLE 10

REGULATORY AUTHORITIES

10.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this

Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

10.2 Subject to the terms of the Settlement in Docket NO. ER09-1279-000, it is expressly understood that any Member under this Agreement, as it may hereafter from time to time be modified and supplemented by the Members, shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 11

ASSIGNMENT

11.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto daily authorized as of the day and year first above written.

Next Page is Signature Page

Transmission Agreement Among:

AMERICAN ELECTRIC POWER
SERVICE CORPORATION,

By:__________________________

Senior Vice President

APPALACHIAN POWER COMPANY,

By:__________________________

President and Chief Operating
Officer

COLUMBUS SOUTHERN POWER
COMPANY,

By:__________________________

President and Chief Operating
Officer

INDIANA MICHIGAN POWER
COMPANY,

By:__________________________

KENTUCKY POWER COMPANY,

By:__________________________

President and Chief Operating
Officer

KINGSPORT POWER COMPANY,

By:__________________________

President and Chief Operating
Officer

OHIO POWER COMPANY, and

By:__________________________

Vice President

WHEELING POWER COMPANY

By:__________________________

President

Dated as of:

____

Appendix I

AEP Transmission Agreement
Allocation of Transmission Related Costs and Revenues

AEP as Transmission Owner (Revenues)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
1	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	NSPL	ARR S1A
2	NITS (AEP LSE)	456.1	NSPL	ATRR
3	NITS (Non-Affiliates)	456.1	NSPL	ATRR
4	Grandfathered PTP (NCEMC)	456.0	Contract	ATRR
5	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	ARR EC
6	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	ARR SC

AEP as LSE (Expenses)

#	Item	FERC Account*	PJM Billing Basis	AEP Allocation Basis
7	Transmission Owner Scheduling, System Control and Dispatch Service (PJM Schedule 1A)	456.1	MWh	MWh
8	NITS Charges (for AEP Retail Load)	456.1	NSPL	12CP
9	NITS Charges for AEP FR Customers[1/]	447.0	NSPL	DA
10	NITS Reimbursement from AEP FR Customers[1/]	447.0	NSPL	DA
11	Firm Point-to-Point Credits (for AEP Retail Load)	456.1	NSPL	12CP
12	Non-Firm Point-to-Point Credits (AEP Retail Load)	456.1	NSPL	12CP
13	Transmission Enhancement (Schedule 12)	565.0	NSPL	12CP
14	PJM Expansion Cost Recovery Charge (ECRC)	456.1	NSPL	12CP
15	RTO Startup Cost Recovery Charge (SCRC)	456.1	NSPL	12CP

NSPL PJM Network Service Peak Load
Contract Pre-OATT FERC Rate Schedules
ARR S1A Annual Revenue Requirement - Schedule 1A
ATRR Annual Transmission Revenue Requirement
ARR EC Annual Revenue Requirement - Expansion Cost Recovery
ARR SC Annual Revenue Requirement - Startup Cost Recovery
12CP Average of 12 coincident peaks through 10/31 of prior year
DA Directly Assigned to Operating Company

* Note: Should the net amount in 456.1 for any Member be negative, e.g. more expense than revenue, the net expense will be recorded in 565.0.

1/ Includes all transmission-related LSE expenses (NITS, Schedule 1A, Point-to-Point Credits, Schedule 12, ECRC, SCRC) which are directly assigned to Operating Company for AEP FR Customers.

Issued By: Richard E. Munczinski
Senior Vice President, Regulatory Services

Effective: first day of the month after the Commission issues a final, non- appealable order accepting the Agreement for filing

Issued On: August 4, 2010