Document Control

Document Review and Approval

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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

<table>
<thead>
<tr>
<th>Internal, External, or Both</th>
<th>Inputs</th>
<th>Examples</th>
</tr>
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<tbody>
<tr>
<td>Internal</td>
<td>Reports on asset conditions</td>
<td>Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)</td>
</tr>
<tr>
<td></td>
<td>Capabilities and abnormal conditions</td>
<td>Relay misoperations; Voltage unbalance</td>
</tr>
<tr>
<td></td>
<td>Legacy system configurations</td>
<td>Ground switch protection schemes for transformers; Transmission Line Taps without switches (hard taps); Equipment without vendor support</td>
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<tr>
<td></td>
<td>Outage duration and frequency</td>
<td>Outages resulting from equipment failures, misoperations, or inadequate lightning protection</td>
</tr>
<tr>
<td></td>
<td>Operations and maintenance costs</td>
<td>Costs to operate and maintain equipment</td>
</tr>
<tr>
<td>External</td>
<td>Regional Transmission Operator (RTO) or Independent System Operator (ISO) issued notices</td>
<td>Post Contingency Local Load Relief Warnings (PCLLRWs) issued by the RTO that can lead to customer load impacts</td>
</tr>
<tr>
<td></td>
<td>Stakeholder input</td>
<td>Input received through stakeholder meetings, such as PJM’s Sub Regional RTEP Committee (SRRTEP) meetings or through the AEP hosted Annual Stakeholder Summits</td>
</tr>
<tr>
<td></td>
<td>Customer feedback</td>
<td>Voltage sag issues to customer delivery points due to poor sectionalizing; frequent outages to facilities directly affecting customers</td>
</tr>
<tr>
<td></td>
<td>State and Federal policies, standards, or guidelines</td>
<td>NERC standards for dynamic disturbance recording</td>
</tr>
<tr>
<td>Both</td>
<td>Environmental and community impacts</td>
<td>Equipment oil/gas leaks; facilities currently installed at or near national parks, national forests, or metropolitan areas</td>
</tr>
<tr>
<td></td>
<td>Safety risks and concerns</td>
<td>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</td>
</tr>
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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](image)

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, Caisson, 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

Link: http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/