Exhibit Booklet	Exhibit Name	Exhibit Description
1	1 - Kentucky Power Company Certificate of Existence	Certificate of Existence that Kentucky Power Company is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B.
1	2 - Project Location Map	Map of the project's location.
1	3A - Proposed Route Map 1A	Includes the aerial background of the proposed route of this project.
1	3B - Proposed Route Map 1B	Includes the topographic background of the proposed route of this project.
2	4A - Alternative Routes Map 2A	Includes the aerial background of the alternative routes of this project.
2	4B - Alternative Routes Map 2B	Includes the topographic background of the alternative route of this project.
2	5 - Proposed Eastern 138kV Substation Location and Layout	Includes station location and layout of the proposed Eastern 138 kV substation.
3	6 - Garrett 138kV Substation Location and Layout	Includes station location and layout of the Garrett 138 kV substation.
3	7 - Soft Shell 138kV Substation Location and Layout	Includes station location and layout of the Soft Shell 138 kV substation.
3	8 - McKinney 46kV Substation Location and Layout	Includes station location and layout of the McKinney 46 kV substation.
3	9 - Beaver Creek 138kV Substation Location and Layout	Includes station location and layout of the Beaver Creek 138 kV substation.
3	10 - Snag Fork	Includes station location and layout of the proposed Snag Fork switching structure.
3	11A - Monopole Dead End Single Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Monopole Dead End Single Circuit.
3	11B - Proposed 138 H Frame Single Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Proposed 138 H Frame Single Circuit.
3	11C - Three Pole Single Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Three Pole Single Circuit.
3	11D - Self Supporting Lattice Single Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Self Supporting Lattice Single Circuit.
3	11E - Dead End Lattice Double Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Dead End Lattice Double Circuit.
3	11F - Monopole Dead End Double Circuit	Includes a typical schematic, typical right-of-way cross section, and comparable existing structure photograph for a Monopole Dead End Double Circuit.
3	12A - Beaver Creek-Garrett 1	Photograph of structure K336-11, which indicates pole splitting.
3	12B - Beaver Creek-Garrett 2	Photograph of structure K336-58, which indicates crossarm splitting.
3	12C - Beaver Creek-Garrett 3	Photograph of structure K336-58, which indicates upper pole split to crossarm attachment.
3	12D - McKinney-Garrett 1	Photograph of structure K337-12, which indicates two (2) broken insulators in string.
3	12E - McKinney-Garrett 2	Photograph of structure K337-12, which indicates one (1) broken insulator in string.
3	12-F McKinney-Garrett 3	Photograph of structure K337-16, which indicates rot-top.
3	12-G McKinney-Garrett 4	Photograph of structure K337-24, which indicates severe Pole Splitting.
3	12-H Spring Fork Tap 1	Photograph of structure K335-9, which indicates pole cavities.
3	12I - Spring Fork Tap 2	Photograph of structure K335-9, which indicates pole rot w/temporary braces in place.
3	12J - Spring Fork Tap 3	Photograph of structure K335-10, which indicates flashover-arcing damage to insulator.
3	13 - Notice To Landowners and Verification of Mailing	Includes verification of the mailing and the notice to landowners of the proposed construction of an electric transmission line project.
3	14 - Present System and Project Components	Map of the present system and proposed project components.

Exhibit Booklet	Exhibit Name	Exhibit Description
3	15 - List of Landowners Within The ROW and 1,000 Foot Corridor	List of landowners within the right-of-way and list of landowners within the 1,000-foot filing corridor.
3	16 - Major Components Of The Proposed Substation Work And Their Purpose	List of the project's major components of the proposed substation work and their purpose.
3	17A - Published Notice and Affidavit 1	Newspaper notice published in Floyd and Knott counties.
3	17B - Published Notice and Affidavit 2	Newspaper notice published in Floyd, Knott, and Breathitt counties.
3	18 - Public News Release	Announcement of the project with information available to the public.
3	19 - Filing Requirements	List of filing requirements in this CPCN proceeding.
4	20 - Siting Study	To identify the most suitable route for the Garrett Area 138 kV transmission line project and proposed site of the Eastern 138 kV Substation.
5	21 - AEP's Guidelines For Transmission Owner Identified Needs	Guidelines to determine the necessity of supplemental projects.
5	22 - PJM Local Plan	Public document at PJM that provides the Need, Solution, and cost estimate at the time of submittal.
5	23 - PJM Solution with Alternative	Public document at PJM that provides the Alternative Solution or Reasonable Alternative and cost estimate at the time of submittal.

AEP Transmission Planning Criteria and Guidelines for End-Of-Life and Other Asset Management Needs

December 2020

Document Control

Document Review and Approval

Action	Name(s)	Title
Prepared by:	Jomar M. Perez	Manager, Asset Performance and Renewal
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Review Cycle

Quarterly	Semi-annual	Annual	As Needed
			X

Revision History

Version	Revision Date	Changes	Comments
1.0	01/04/2017	N/A	1st Release
2.0	1/18/2018	Format Update	2nd Release
3.0	11/09/2018	Content Additions	3rd Release
4.0	12/14/2020	End-Of-Life Criteria	4th Release

Table of Contents

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 these issues as transmission owner identified needs that address condition, performance and risk. AEP identifies these needs through the transmission planning criteria and guidelines outlined in this document. Specifically, this document constitutes the AEP transmission planning criteria and guidelines for End-Of-Life and other asset management needs as required in the FERC-approved Attachment M-3 to the PJM Tariff. AEP does not address any End-Of-Life or other asset management needs through the baseline planning criteria AEP files with its FERC Form 715.

AEP's transmission owner identified needs must be addressed to achieve AEP's obligations and responsibilities. Meeting these obligations 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, criteria and 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].

Whereas the End-Of-Life needs, as defined in the FERC-approved Attachment M-3 to the PJM Tariff, are limited to transmission facilities rated above 100 kV, these criteria and guidelines apply to all transmission voltages that comprise the AEP transmission system, including those defined as End-Of-Life needs in the FERC-approved Attachment M-3 to the PJM Tariff. In addition, projections of candidate End-Of-Life needs that result from the process outlined in these AEP criteria and guidelines will be provided to PJM in accordance with the provisions in the FERC-approved Attachment M-3 to the PJM Tariff. Current End-Of-Life and other asset management needs will be vetted with stakeholders in accordance with the provisions in the FERC-approved Attachment M-3 to the PJM Tariff.

Addressing these owner identified transmission system asset management needs, as they pertain to condition, performance and risk, will result in the following benefits to customers:

- 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 resilience) associated with man-made and environmental threats.
- Proactive correction of reliability constraints that stem from asset failures.
- Effective utilization of resources to provide efficient and cost-effective service to customers.

2.0 Process Overview

AEP's transmission owner needs identification criteria and guidelines are used for projects that address equipment material conditions, performance, and risk. 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 Identifying and Addressing Transmission Asset Condition, Performance and Risk 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 collective evaluation of these inputs is conducted and considered, and thus, individual thresholds do not apply. In addition, factors can change over time. 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

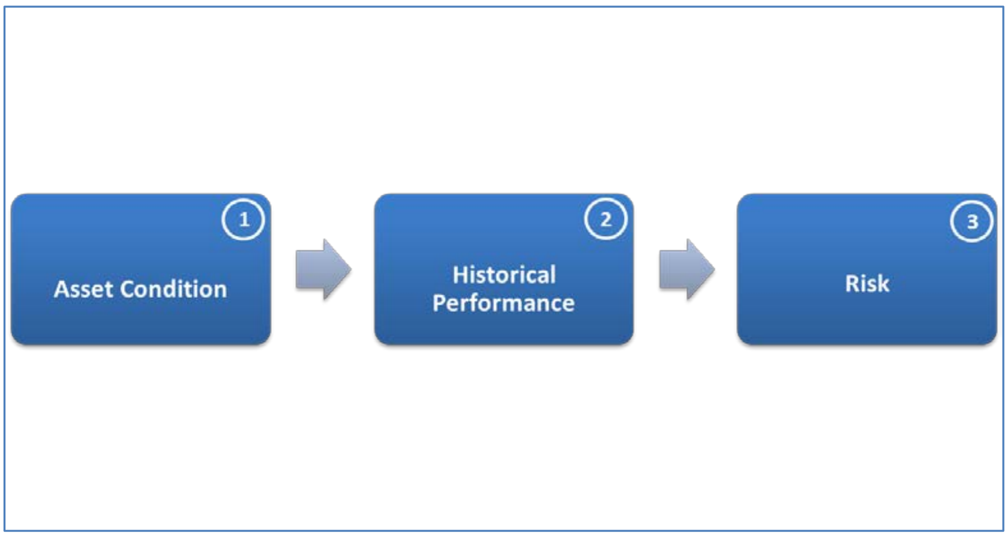
Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperations; Voltage unbalance
	Legacy system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

These inputs are reviewed and analyzed to identify the transmission assets that are exhibiting unacceptable condition, performance and risk, and thus, must be addressed through the FERC-approved Attachment M-3 planning process.

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 and goal to develop and provide the more efficient, cost-effective, safe, reliable, resilient, 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 baseline planning criteria violations on the transmission grid. Finally, AEP reviews its existing portfolio of baseline planning criteria driven reliability projects and evaluates opportunities to combine or complement existing baseline 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 more 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 baseline 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 criteria and guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk. 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 criteria and 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/

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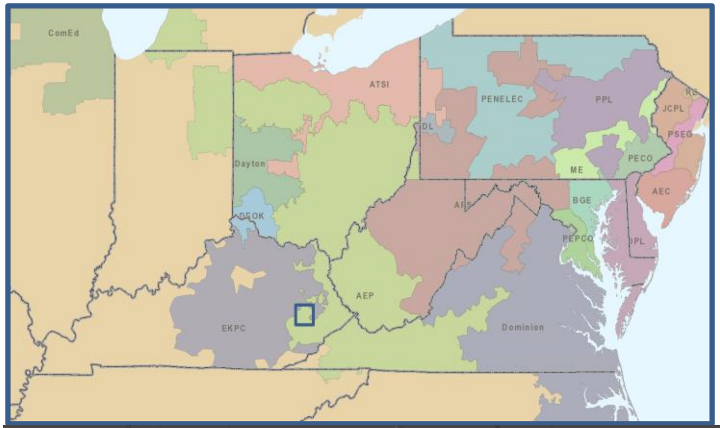


Need Number: AEP-2019-AP017

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/10/2020

Previously Presented:

Needs Meeting 6/17/2019

Solutions Meeting 2/21/2020

Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption Reference:

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

Problem Statement:

Beaver Creek – McKinney #1 46 kV Circuit

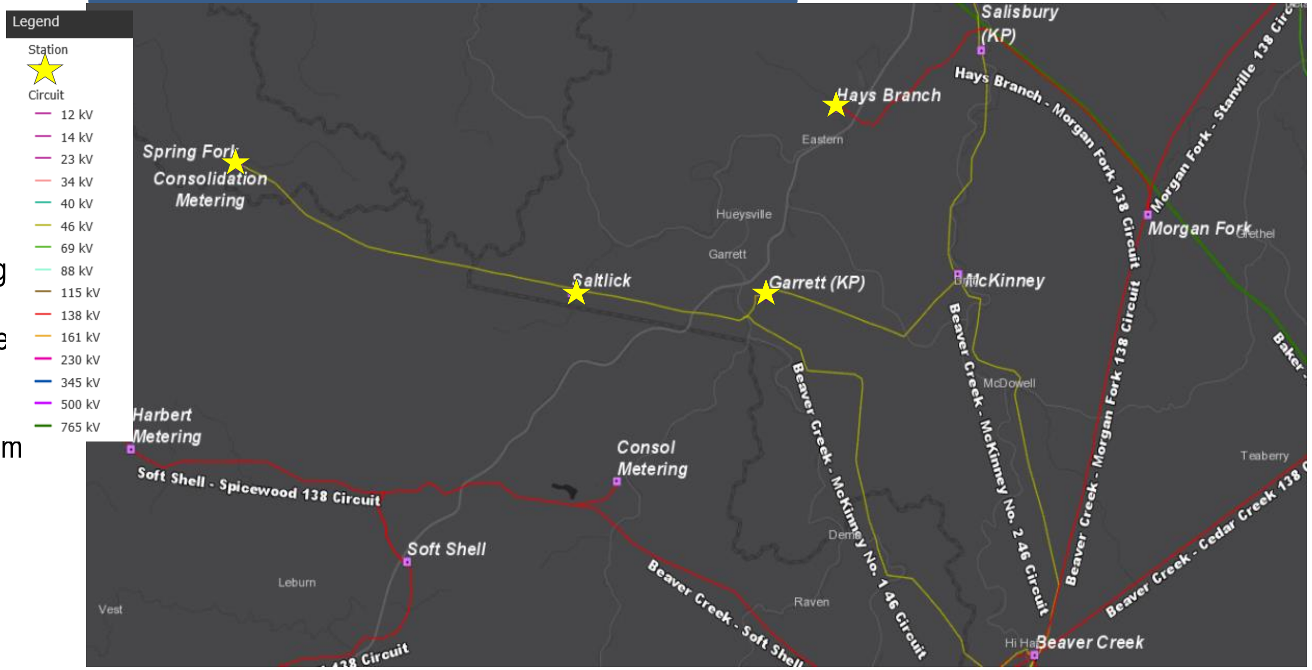
- From 2016-2018, the approximately 24.6 mile Beaver Creek – McKinney #1 46 kV circuit has experienced 22 outages.
- The circuit is comprised of 152 structures, the majority of which are wood structures dating back to 1929 (22/152, 14%) and 1949 (61/152, 40%).
- There are 142 open conditions along the 24.6 mile long line. These include damaged pole and cross-arms, conductor/shield wires, and guy anchor/knee/vee braces.

Hays Branch Station

- Hays Branch serves a ~30 MW gas compressing operation that is currently radially fed from a ~8.25 mile line out of Morgan Fork station.

Saltlick Station

- Saltlick serves an EKPC co-op that is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.



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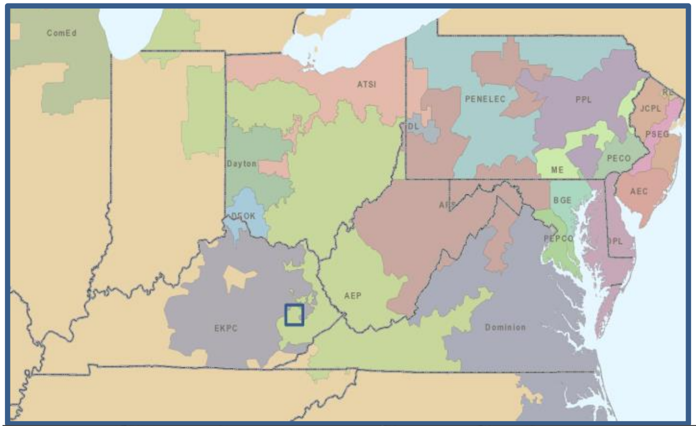
Continued from previous slide…

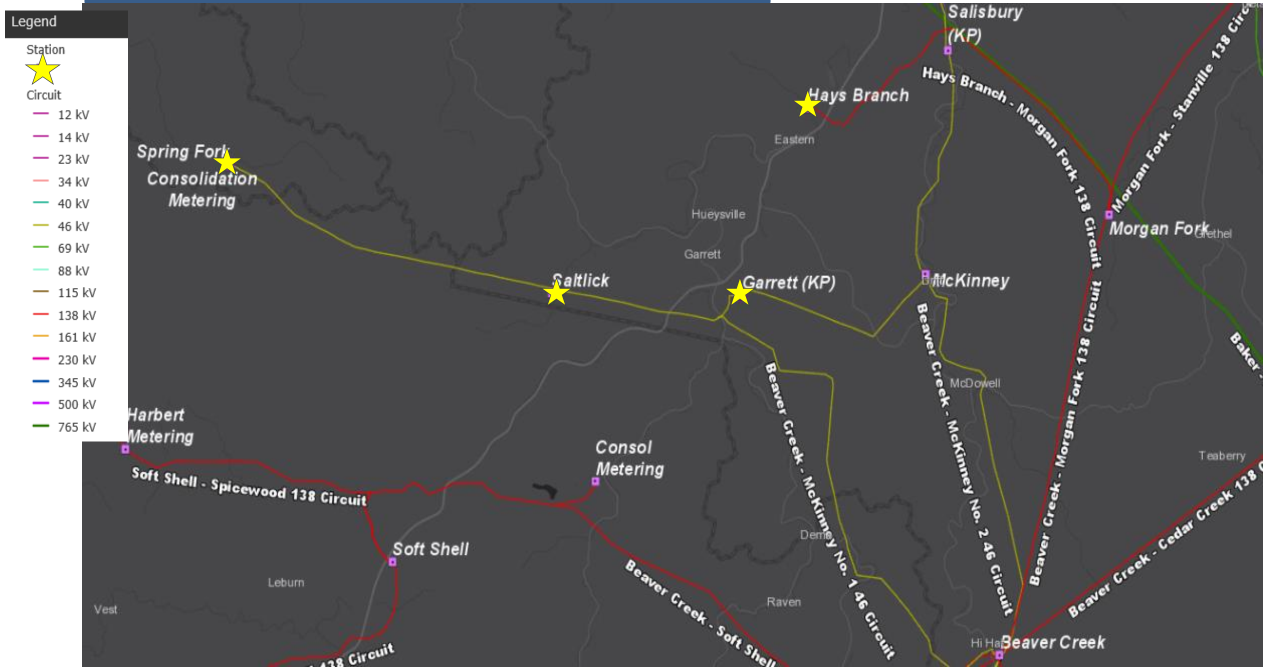
Spring Fork

- Spring Fork station serves KPCo distribution customers and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.

Consolidation Metering

- Consolidation Metering station serves a mining operation and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.





Need Number: AEP-2019-AP017
Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/10/2020

Selected Solution:
Construct ~~~9.3~~ 10.3 miles of single circuit 138kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way. Complete associated remote end relaying.
(S2188.1) **Estimated Cost: $35.3M**

Construct ~3~~.5~~ miles of single circuit 138kV from the Eastern station to Garrett station. A short extension will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork – Hays Branch 138 kV circuit from Eastern station
(S2188.2) **Estimated Cost: $11.5M**

Double circuit cut into existing Hays Branch - Morgan Fork line to tie into new Eastern station. ~~Hays Branch S.S PoP switch. Installation of a new heavy double circuit dead-end tap structure on the existing Hays Branch – Morgan Fork 138kV Line (Due to unequal loading on the transmission line).~~
(S2188.3) **Estimated Cost: $1.3M**

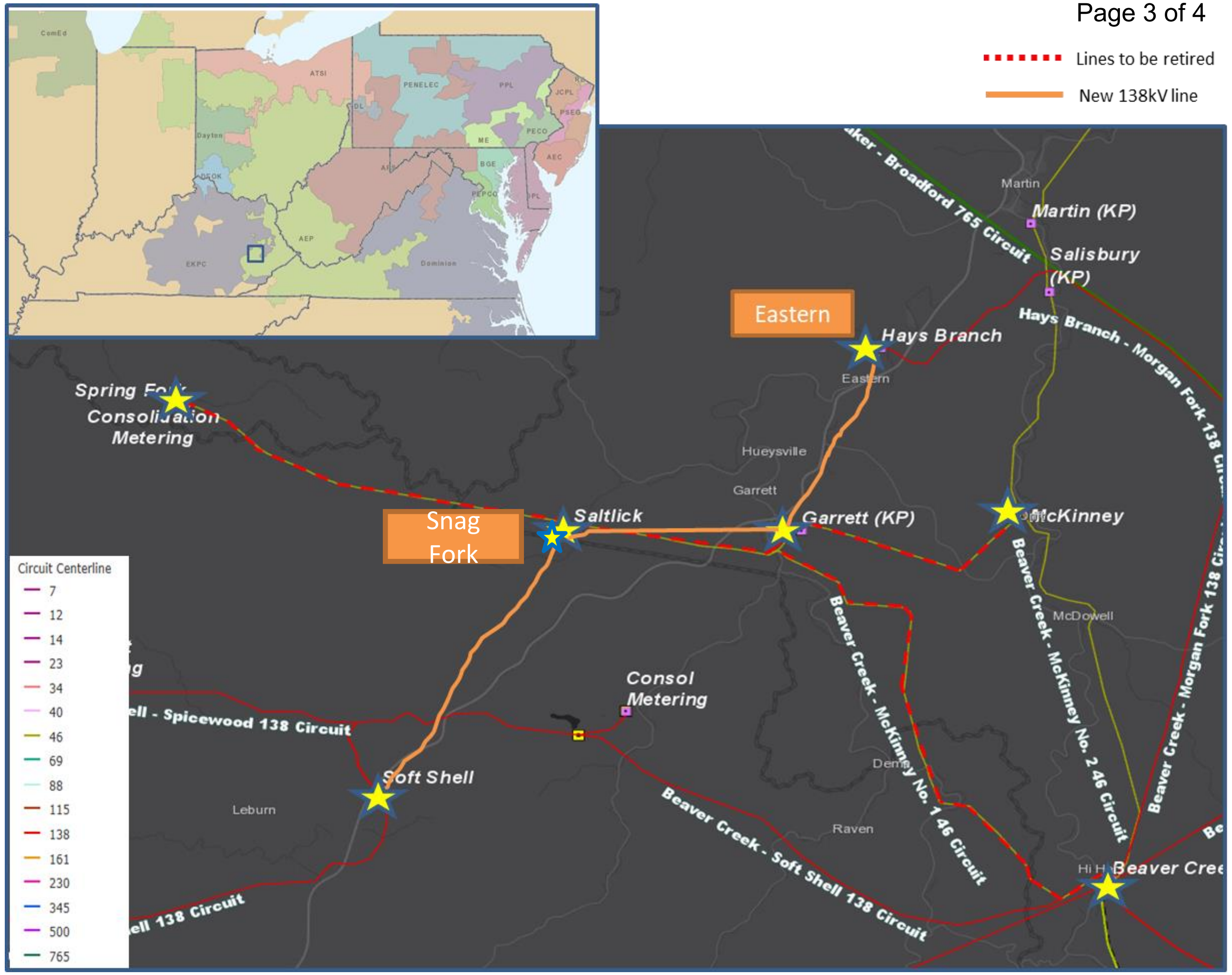
Construct ~~~0.25~~ 1.4 mi of double circuit 138kV line between ~~Hays Branch S.S~~ Eastern and the tap point on the Morgan Fork-Hays Branch line. The proposed line will establish a direct feed to Hays Branch from Eastern and establishing a through path line between Eastern and Morgan Fork. ~~Installation of 3 double circuit suspension structures one of which is a custom pole structure.~~
(S2188.4) **Estimated Cost: $1.6M**

New ~~PoP switch structure~~ relaying at Hays Branch to accommodate new line from Eastern station
(S2188.5) **Estimated Cost: $0.5M**

Expand the Garrett station, Install ~~a 138kV three breaker ring bus (If space becomes a constraint, we should look at installing~~ a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer~~)~~, 138/12kV 30 MVA transformer
(S2188.6) **Estimated Cost: ~~$5.8M~~ $0.0M**

Establish a new 138 kV substation Eastern south of the existing Hays Branch station. Install ~~two~~ three 138kV breakers (3000A 40kA) at the new Eastern station ~~on exits toward Morgan Fork and Garrett station~~ in a ring bus arrangement.
(S2188.7) **Estimated Cost: $6 M**

Establish Snag Fork S.S. Install a 3 way phase over phase motorized (automated) switching structure near Saltlick to serve the EKPC co-op.
(S2188.8) **Estimated Cost: $1.1 M**



AEP Transmission Zone M-3 Process
Garrett Area Improvements

Proposed Solution (Cont.):

Move the existing 69kV rated CB G to the Beaver Creek – McKinney #2 circuit exit at McKinney substation. (**S2188.9**) **Estimated Cost: $0.0 M**

Install a 138kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation. (**S2188.10**) **Estimated Cost: ~~$0.8 M~~ $0.0M**

Retire the ~25 miles of the 46kV Beaver Creek – McKinney #1 46 KV circuit. Retire Spring Fork Tap. (**S2188.11**) **Estimated Cost: $17.3 M**

Ancillary Benefits: Removal of obsolete ~25 mi of 46kV network.

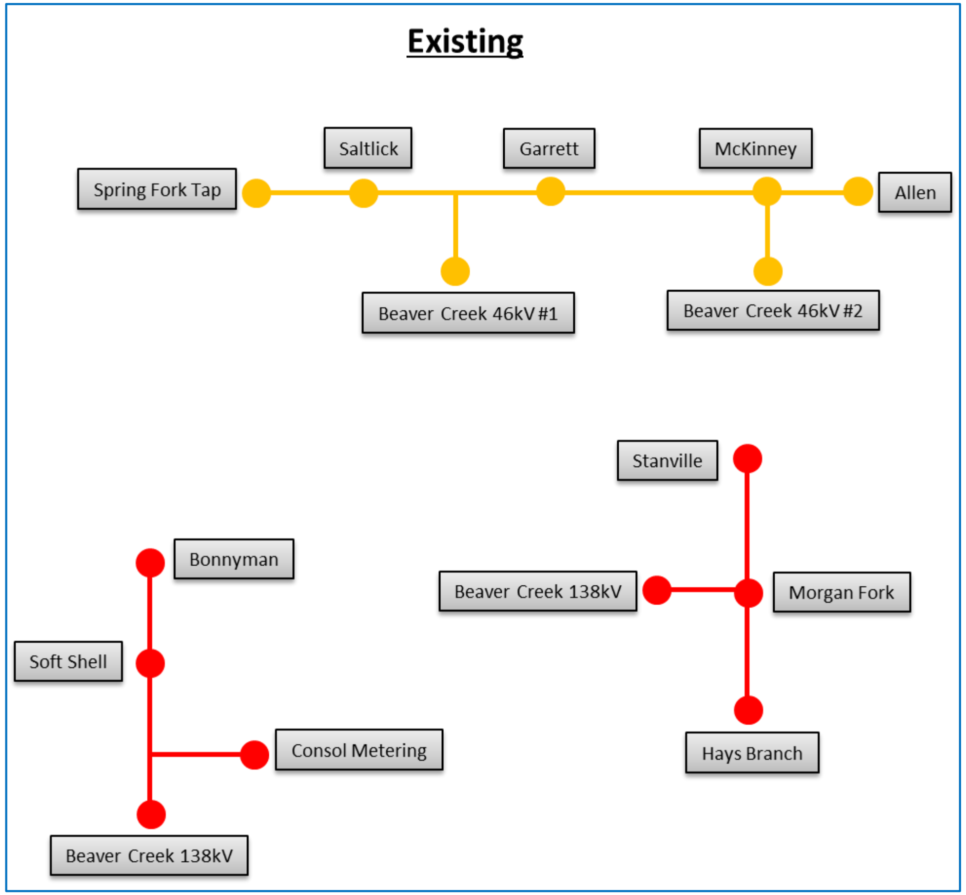
Estimated Cost: ~~$81.2M~~ $74.6M

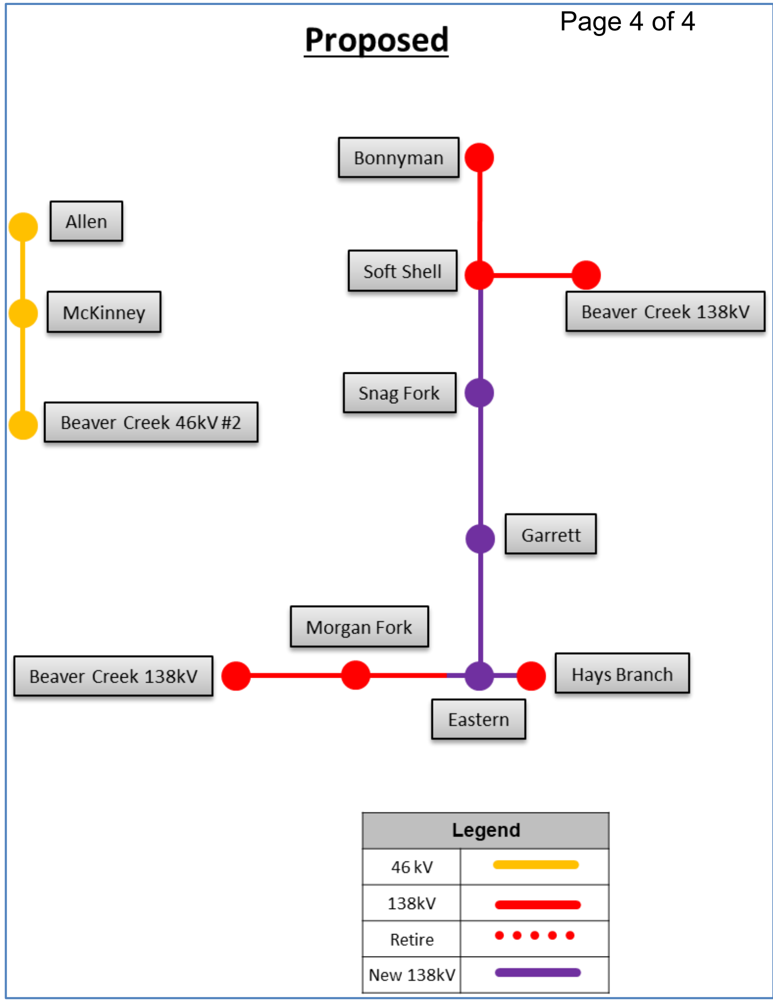
Projected In-Service: ~~10/31/2023~~ 11/15/2024

Supplemental Project ID: S2188.1-.11

Project Status: Scoping

Model: N/A





Case No. 2021-00346
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Need Number: AEP-2019-AP017

Process Stage: Solutions Meeting 02/21/2020

Previously presented: Need Meeting 06/17/2019

Supplemental Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption References:

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

Problem Statement:

Beaver Creek – McKinney #1 46 kV Circuit

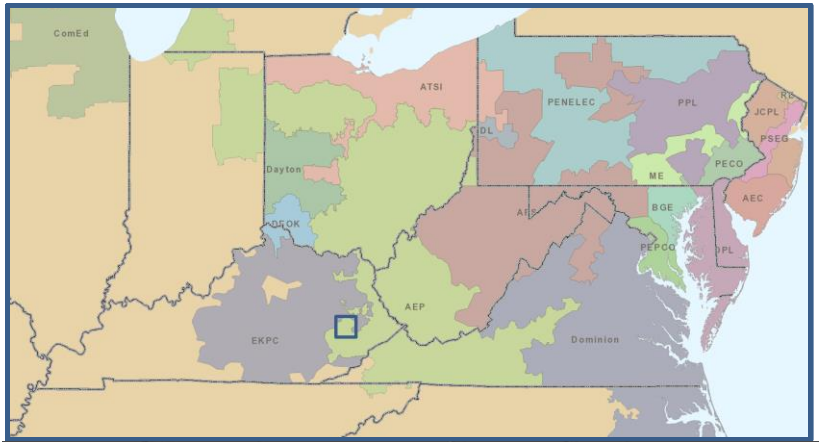
- From 2016-2018, the approximately 24.6 mile Beaver Creek – McKinney #1 46 kV circuit has experienced 22 outages.
- The circuit is comprised of 152 structures, the majority of which are wood structures dating back to 1929 (22/152, 14%) and 1949 (61/152, 40%).
- There are 142 open conditions along the 24.6 mile long line. These include damaged poles and cross-arms, conductor/shield wires, and guy anchor/knee/vee braces.

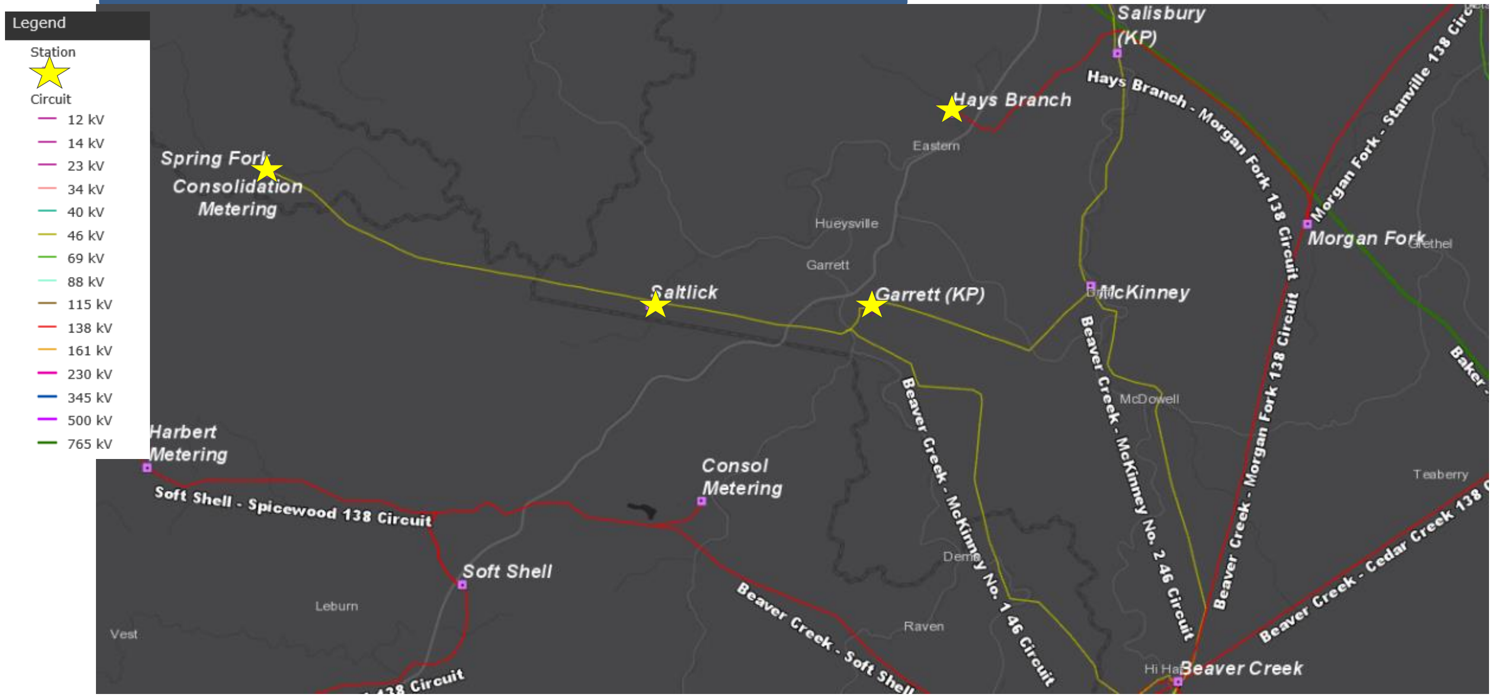
Hays Branch Station

- Hays Branch serves a ~30 MW gas compressing operation that is currently radially fed from a ~8.25 mile line out of Morgan Fork station.

Saltlick Station

- Saltlick serves an EKPC co-op that is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.





AEP Transmission Zone: Supplemental
Floyd County, Kentucky

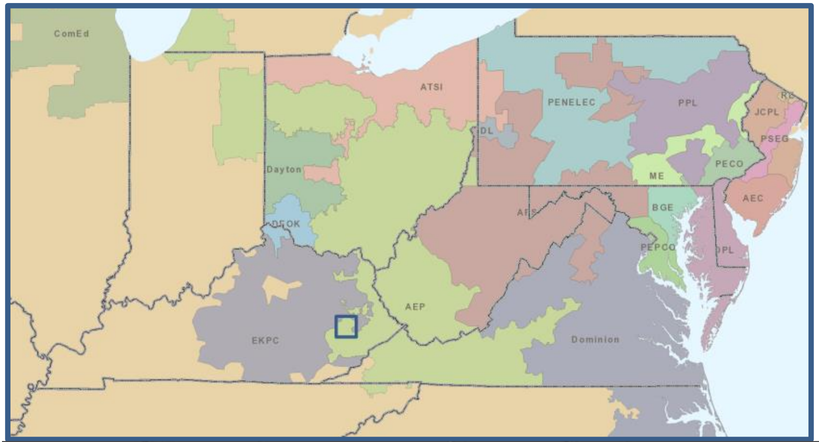
Continued from previous slide…

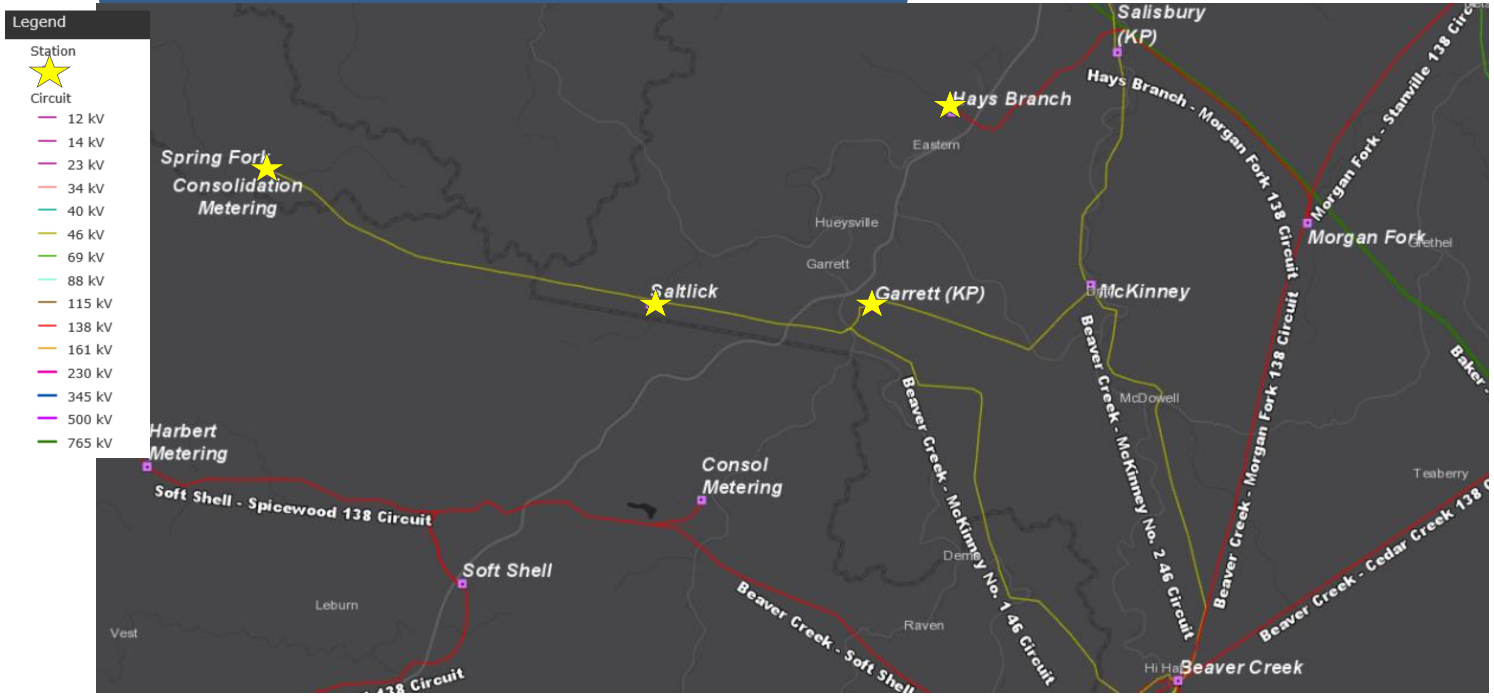
Spring Fork

- Spring Fork station serves KPCo distribution customers and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.

Consolidation Metering

- Consolidation Metering station serves a mining operation and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.





Proposed Solution:

Construct ~9.3 miles of single circuit 138kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way.

Estimated Cost: $35.3M

Construct ~3.5 miles of single circuit 138kV from the Eastern station to Garrett station. A short extensio will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork – Hays Branch 138 kV circuit from Eastern station

Estimated Cost: $11.5M

Double circuit cut into existing Hays Branch - Morgan Fork line to tie into new Hays Branch S.S PoP switch. Installation of a new heavy double circuit dead-end tap structure on the existing Hays Branch – Morgan Fork 138kV Line (Due to unequal loading on the transmission line).

Estimated Cost: $1.3M

Construct ~0.25 mi of double circuit 138kV line Hays Branch S.S – Eastern. Installation of 3 double circuit suspension structures one of which is a custom pole structure.

Estimated Cost: $1.6M

New PoP switch structure at Hays Branch to accommodate new line from Eastern station

Estimated Cost: $0.5M

Expand the Garrett station, Install a 138kV three breaker ring bus (If space becomes a constraint, we should look at installing a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer), 138/12kV 30 MVA transformer

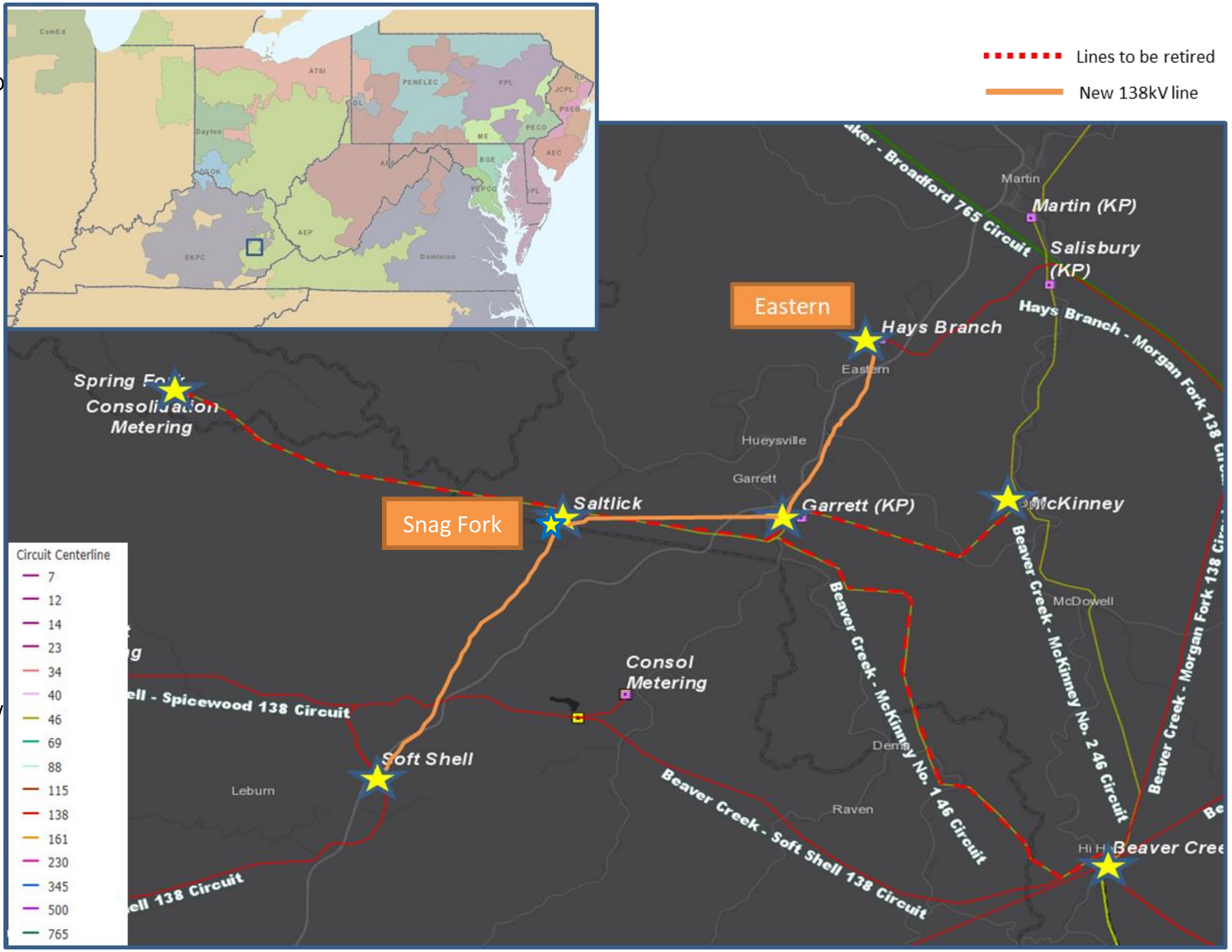
Estimated Cost: $5.8M

Establish a new 138 kV substation Eastern south of the existing Hays Branch station. Install two 138kV breakers (3000A 40kA) at the new Eastern station on exits toward Morgan Fork and Garrett station.

Estimated Cost: $6 M

Establish Snag Fork S.S. Install a 3 way phase over phase motorized (automated) switching structure near Saltlick to serve the EKPC co-op.

Estimated Cost: $1.1 M



AEP Transmission Zone: Baseline Garrett Area Improvements

Proposed Solution (Cont.):

Move the existing 69kV rated CB G to the Beaver Creek – McKinney #2 circuit exit at McKinney substation.
Estimated Cost: $0.9 M

Install a 138kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation.
Estimated Cost: $0.8 M

Retire the ~25 miles of the 46kV Beaver Creek – McKinney #1 46 KV circuit. Retire Spring Fork Tap.
Estimated Cost: $17.3 M

Total Estimated Transmission Cost: $81.9 M

Ancillary Benefits: Removal of obsolete ~25 mi of 46kV network.

Alternative Solution:

Rebuild Beaver Creek – McKinney 46 kV #1 (approximately 25.0 miles) circuit keeping the system configuration as is. Construct new ~6.5 miles of 138kV line from Stanville station. Convert the ~3.5 mi 138kV existing single circuit to double circuit 138kV line from Hays Branch to newly constructed 138kV from Stanville making one feed for Hays Branch from Morgan Fork and other from Stanville.
Estimated Cost: $105 M

Projected In Service Date: 10/31/2023
Project Status: Scoping