Western Sub Regional RTEP: AEP Supplemental Projects

January 16, 2026

Changes to the Existing Supplemental Project

AEP Transmission Zone: Supplemental S2888 Scope Change

S2888: Posted in 2023 Local Plan. Need Number: AEP-2022-IM008. Solution Meeting on 01/20/2023.

Original Solution presented in 2023 SRRTEP:

Adams – Berne 69 kV structure replacement: Replace ~4.9 miles of 69 kV line structures. The following cost includes the structure replacements, structure removals, ROW and station connections.

Revised Solution: Rebuild the Adams- Berne 69 kV line ~4.9 miles

Original estimated cost presented in 2023 SRRTEP: $12.8M

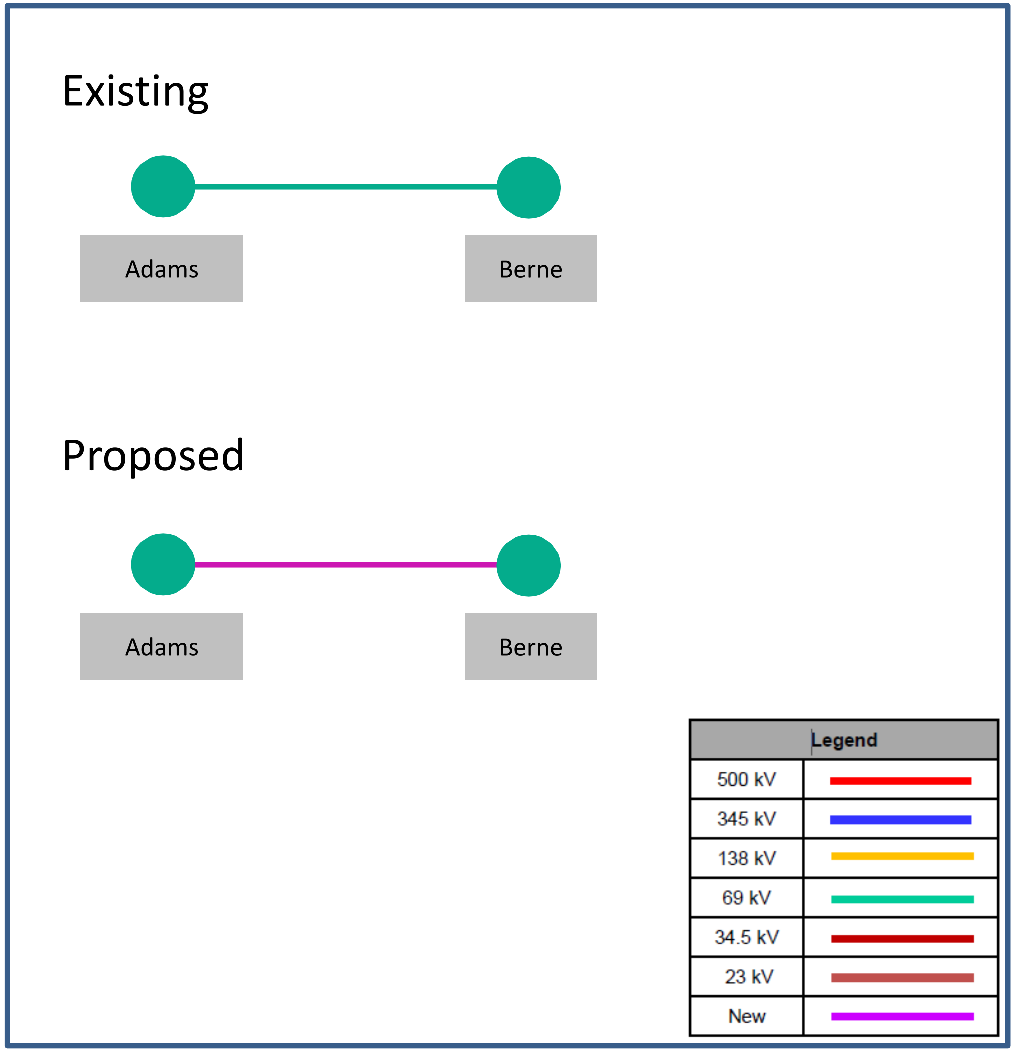
Revised Cost with Scope Change: $19.45M

Original Projected In-Service date: 11/01/2026

Revised projected In-Service date: 2/13/2029

Reason For Change:

During detailed engineering and design for the proposed work, it was determined that a complete line rebuild of the ~4.9 miles of the Adams – Berne 69 kV line is more cost effective than replacing structures replacement along the line as originally scoped (Original Scope would cost $22.85M today, thus rebuilt save $3.4M). Given the existing line has H-frame structures, a structure only replacement project would require to replace with H-frame structures due to constructability. H-frame structures consist of two steel poles versus a complete line rebuild would replace the H-frame structure with one steel pole structure hence a lesser number of steel monopole structures to be installed overall.



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

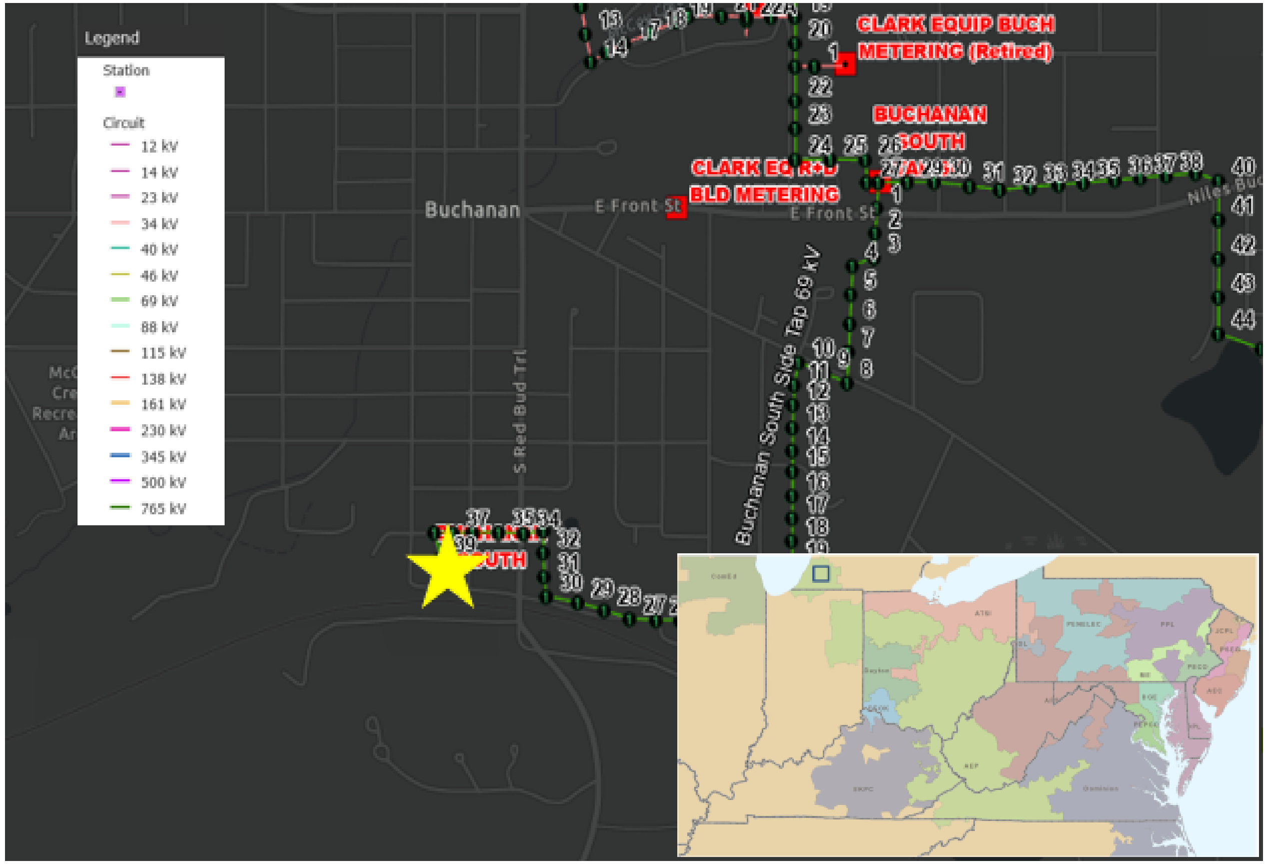
Need Number: AEP-2026-IM001

Process Stage: Need Meeting 01/16/2026

Project Driver: Equipment Condition/Performance/Risk

Specific Assumption References:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 13)



Problem Statement:

Buchanan South 69kV Station:

- At the line entrances, there are cap and pin insulators that are known for failure and can result in a station outage.
- The current transformer protection scheme is set up with a ground switch, which is not ideal and has had operational issues in the past.
- The current location of the station provides challenges to accessibility, making it difficult to pull in a mobile unit to support planned or unplanned outages.
- With the difficulties of installing a mobile at the station, there have been 4 scheduled outages since 2019 resulting in 446,877 customer minutes of interruption.

Need Number: AEP-2026-AP001

Process Stage: Need Meeting 01/16/2026

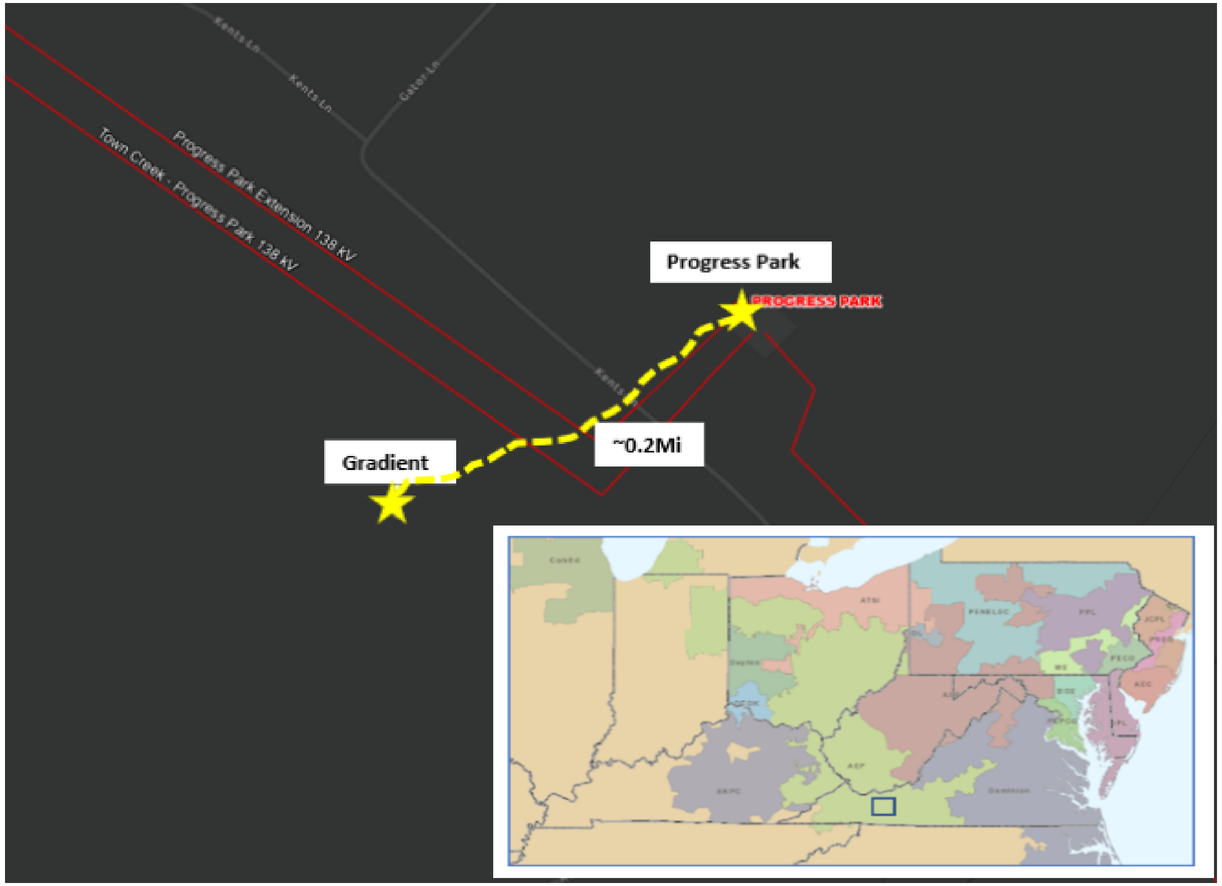
Project Driver: Customer Service

Specific Assumption References:

AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 12).

Problem Statement:

A customer has requested new 138 kV service in Wytheville, VA. T he ultimate peak demand is 240MW. Customer requested in-service date is Q1 2027.



Need Number: AEP-2026-OH001

Process Stage: Need Meeting 01/16/2026

Project Driver: Customer Service

Specific Assumption References:

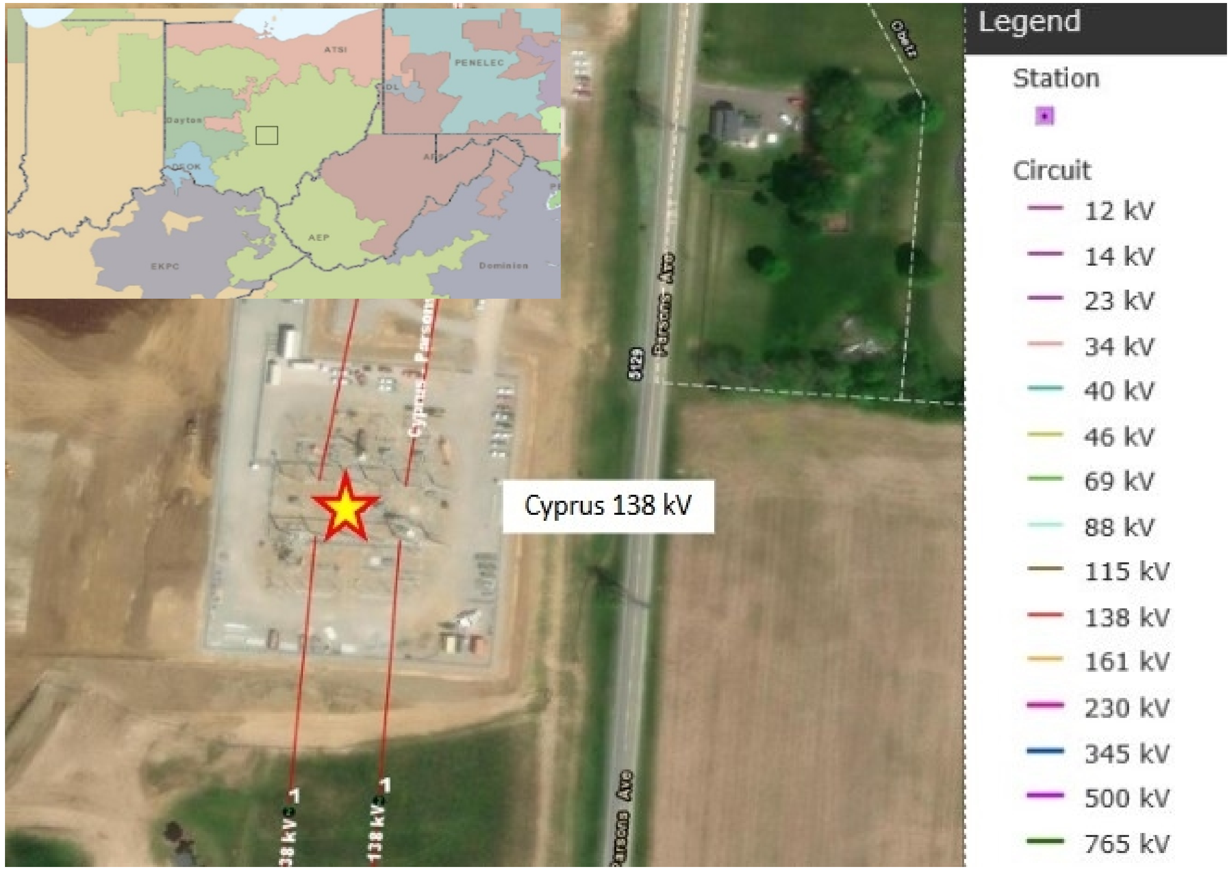
AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 12)

Problem Statement:

A customer has requested additional 138 kV delivery points to their site in Columbus Ohio, just south of AEP's Cyprus station to serve the next phase of their construction.

There is no additional load to be added under this request. The total load served at this site will remain at 388 MW. Ultimate demand at the site is expected to be 675 MW.

Customer requested in-service date of Q2 2027.



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
Haverhill, Ohio

Need Number: AEP-2022-OH002

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Previously Presented: Need Meeting 01/21/2022

Project Driver:

Equipment Material/Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 13)

Problem Statement:

North Haverhill Station

Circuit Breakers (69kV): M & P (1200 A)

- Breaker Age: 1968 (M), 1977 (P)
- Interrupting Medium: (Oil)
- Fault Operations:
    - Number of Fault Operations: M-13 & P-36
- These breakers are oil filled without oil containment; oil filled breakers have much more maintenance required due to oil handling that their modern, SF6 counterparts do not require. This model family has experienced major malfunctions associated with their hydraulic mechanisms, which includes low-pressure readings, hydraulic leaks, pump lockouts, and failure to shut off. These mechanism malfunctions have led to several failures to close and other types of mis-operations across the AEP fleet.

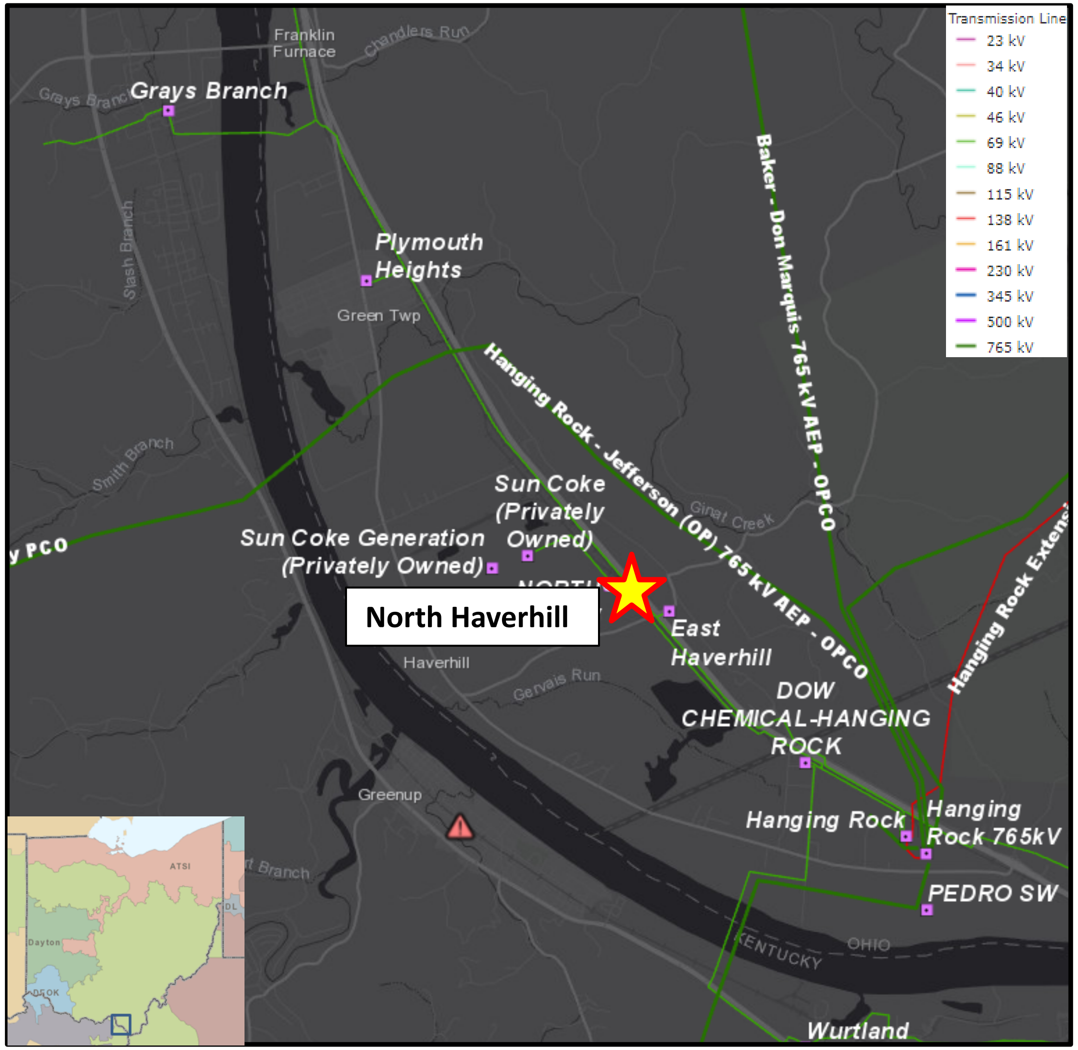
Circuit Switcher (69kV): AA

- Switcher Age: 1991 (1200 A)
- Interrupting Medium: (SF6)

This family of circuit switchers have no gas monitor and currently in-service units on the AEP System have experienced 80 malfunctions from May 2002 to August 2019. The major malfunction events include gas loss, interrupter failures, operating mechanism failures, and trip or reclose failures. Models manufactured from January 1986 to December 1995 have a high potential for broken spring carriers in the low gas target assembly. This component malfunction presents the possibility of an actual low gas situation going unnoticed due to the indicator not activing. Interrupters can only be replaced, not repaired, as they are hermetically sealed.

Relaying:

- Currently, 65 of the 65 relays (100% of all station relays) are in need of replacement. 38 of these are of the electromechanical type and 2 of the static type which have significant limitations with regards to spare part availability and fault data collection and retention as these relays are no longer supported by the manufacturer. There are also 25 microprocessor-based relays commissioned in 2004-2009 that have firmware that is no longer supported.



Need number(s): AEP-2022-OH002

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Proposed Solution:

North Haverhill Station: At North Haverhill station, replace breakers 'M' and 'P' with 3000A 40 kA 69 kV breakers. Add bus tie breaker. Replace 69 kV capacitor switcher 'AA' with new 2000 A/40 kA interrupting device. Replace Relays. . Estimated Cost: $12.985 M

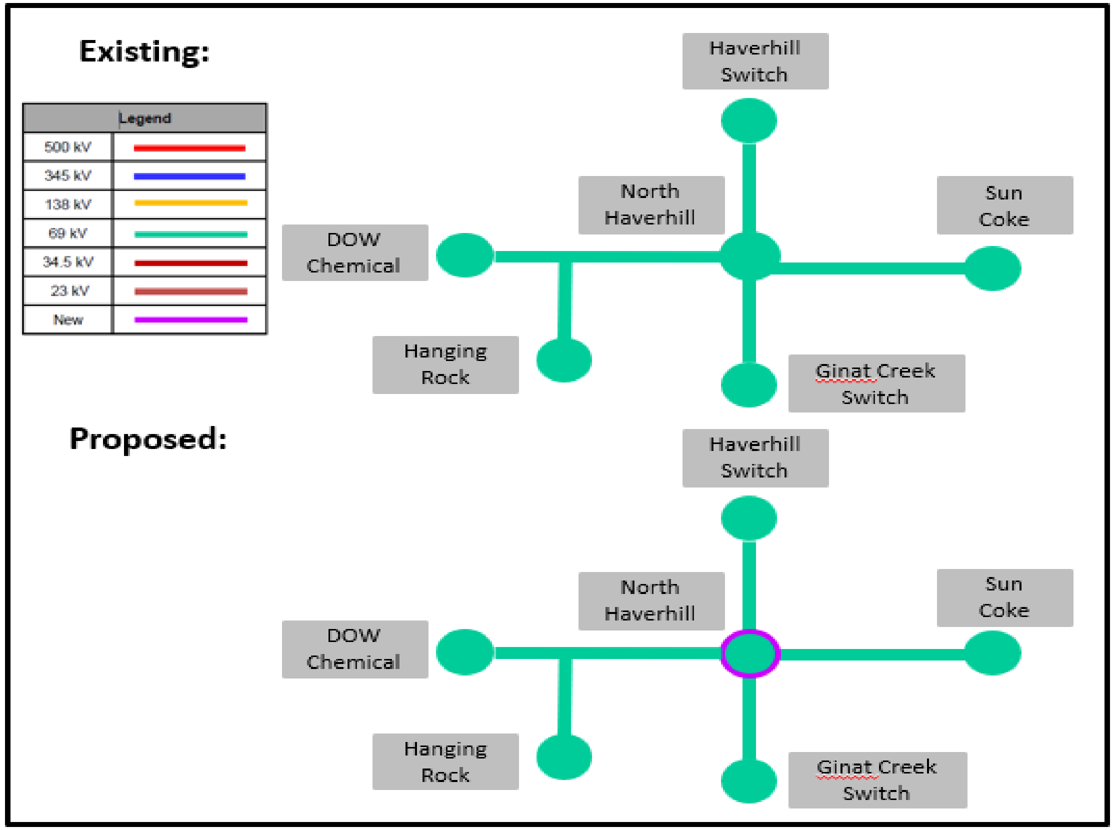
Transmission Cost Estimate: $12.985 M

Alternatives Considered:

Rebuild North Haverhill station as a greenfield 69kV, 6 - Circuit breaker ring bus. Considering the availability of space at the existing location to complete the work, this option was not chosen. Estimated cost: $20.2M

Projected In-Service: 03/01/2027

Project Status: Conceptual



Need Number: AEP-2025-OH002

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Previously Presented: Need Meeting 02/14/2025

Supplemental Project Driver: Customer Service, Operational Flexibility and Efficiency

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 12 & 14)

Problem Statement:

A customer is served via a ~0.44 mi radial hard tap from the ~2.93 mi Busch Switch – Lazelle 69 kV Circuit, with no line sectionalizing switches present. The hard tap limits operational capabilities in the area; it's difficult to coordinate maintenance efforts because the T-line cannot be removed from service without a customer outage. Hard taps are a legacy customer connection option that are gradually being eliminated from the transmission system, due to their customer inconveniences and lower reliability.

Need number(s): AEP-2025-OH002

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Proposed Solution:

Sancus Switch: Install a 69 kV 2000A three-way phase over phase MOAB switch with automatic reclosing and SCADA control capability to replace the hard tap..
Estimated Cost: $4.44 M

Transmission Cost Estimate: $4.44 M

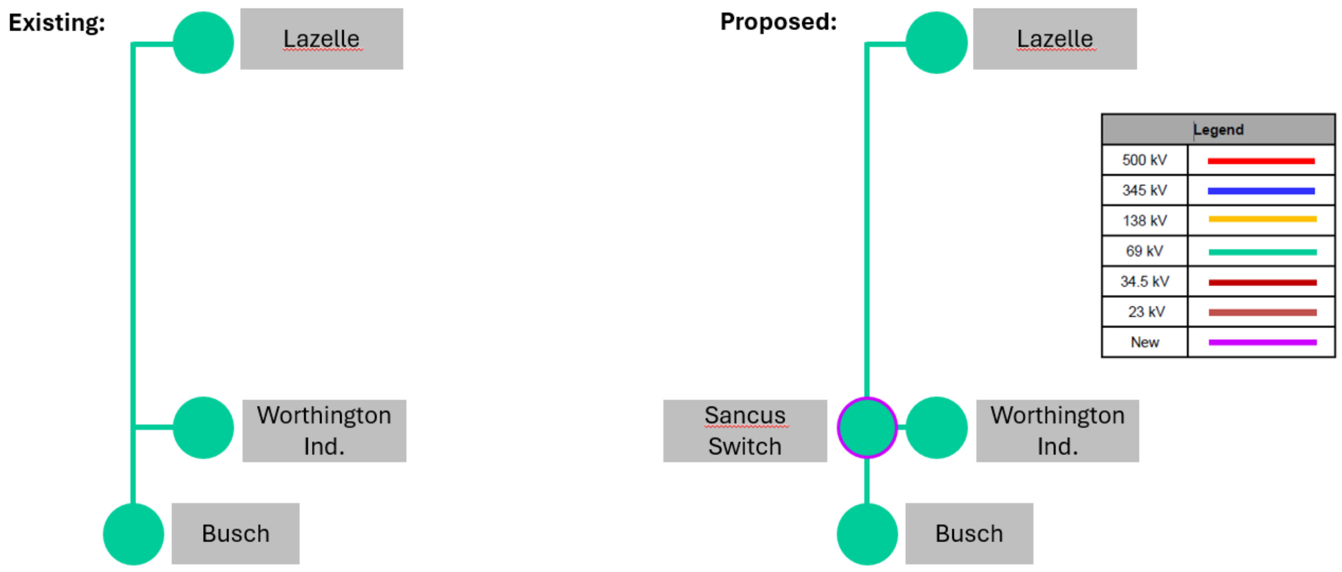
Alternatives Considered:

Considering the location of the line and customers served from it and the limited scope of the solution, no other viable transmission alternates were identified.

Projected In-Service: 12/28/2027

Project Status: Engineering

Bubble Diagram



AEP Transmission Zone M-3 Process
Hannibal, WV

Need Number: AEP-2025-OH012

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Previously Presented: Need Meeting 07/18/2025

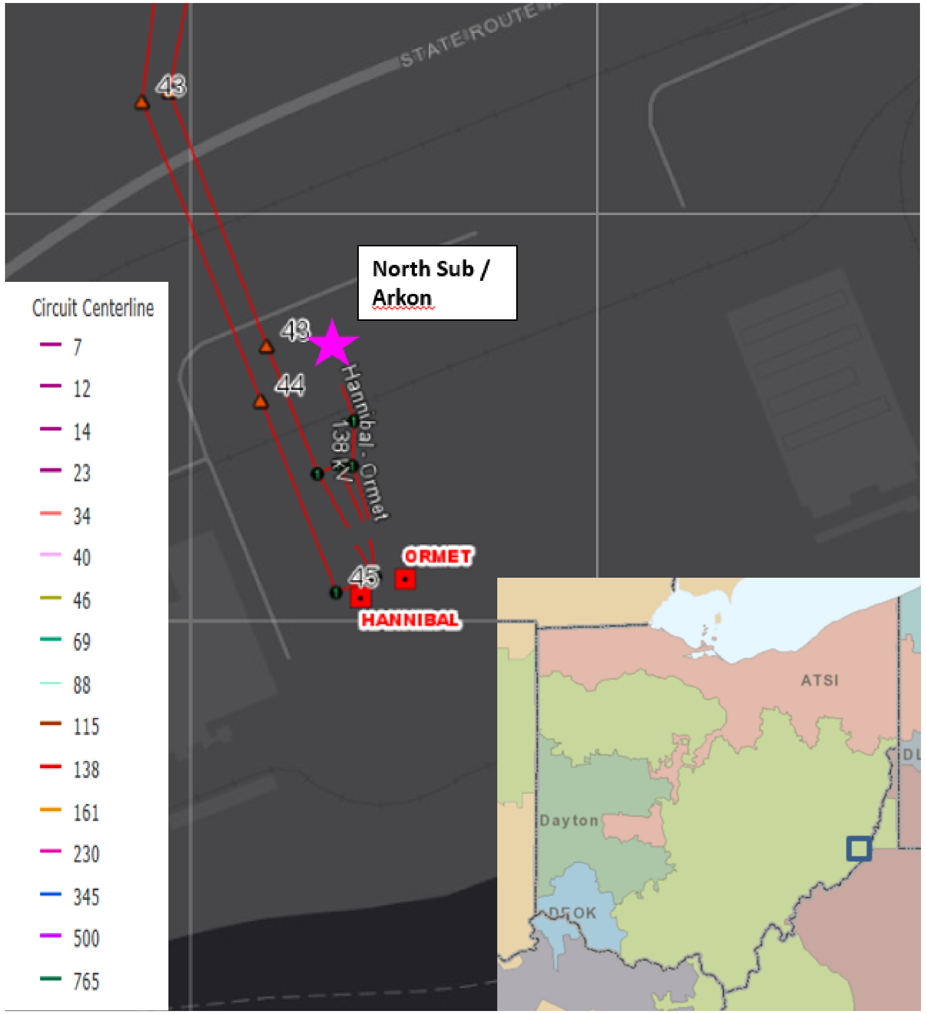
Project Driver: Customer Service

Specific Assumption References:

AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 13)

Problem Statement:

A customer planned to be served out of Hannibal 138kV substation has requested a new load addition of 304 MW. The total anticipated load to be served at the site is 570 MW. The customer has requested service by 5/9/2027.



Need number(s): AEP-2025-OH012

Process Stage: Solution Meeting SRRTEP-W - 01/16/2026

Proposed Solution:

Hannibal Station Work: Install 1 - 138 kV 3000A 63 kA circuit breaker in addition to the 3 being installed with AEP-2024-OH040, to accommodate the additional customer feed. Estimated Cost: $1.344 M

Hannibal - Customer 138 kV Feed: Install ~0.25 miles of 1590 KCM 54/19 FALCON ACSS conductor on the open side of the double circuit structures which will be installed with AEP-2024-OH040. Estimated Cost: $0.532 M

Transmission Cost Estimate: $1.875 M

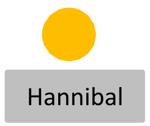
Alternatives Considered:

Considering the location of the customer facilities and timing of the request, no other viable transmission alternatives were identified.

Projected In-Service: 10/26/2026

Project Status: Engineering

Existing



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

Proposed

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

01/06/2026– V1 – Original version posted to pjm.com