COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power	)	
Company For A Certificate Of Public Convenience	)	
And Necessity To Construct A 161 kV	)	Case No. 2017-00328
Transmission Line In Perry And Leslie Counties,	)	
Kentucky And Associated Facilities	)	
(Hazard-Wooton Line)	)	

KENTUCKY POWER COMPANY

RESPONSES TO

ATTORNEY GENERAL'S SECOND SET OF DATA REQUESTS

February 9, 2018

REQUEST

AG_2_001 Refer to the Company's Response to Staff's Initial Request for Information ("RFI")Question 4. Explain whether the estimated OATT revenue requirement of $5.9 million includes the cost of this project.

a. State whether the approximate $300,000 in annual NITs cost (of the $5.9 million revenue requirement) is what the Company estimates it will pay after the completion of this project. If not, explain what the Company expects to pay in annual NITs costs.

b. Refer to the Company's Response to the Attorney General's Initial RFI Question 5, where the Company estimates that approximately $20 million of the cost of the project is Baseline, while $24.5 million is Supplemental. Assuming these project costs are approved, explain whether the Company has calculated the rate impact on customers of each class.

c. Considering all transmission costs (total and this project), and using the Company's best estimate, state the current allocation of these costs across rate classes, and fully explain the reasoning behind the allocation.

d. Provide a breakdown of the total allocation according to the Supplemental and Baseline portions of the project.

e. Describe the projected cost allocation of the projects listed in the Company's Response to the Attorney General's Initial RFI Question 1.c.

RESPONSE

Yes.

a. The estimated $300,000 represents the annual NITS expense the Company will incur related to the project once the project goes in service.

b. Yes.

c - e. Regardless of whether the project is classified as baseline or supplemental, the cost will be recovered through tariff PPA. The Company estimates (based upon the allocations recently approved by the Commission in Case No. 2017-00179) that the estimated $300,000 annual NITS expense will be allocated to the customer classes using the following approximate percentages:

RS - 49%
GS - 12%
LGS - 11%
IGS - 28%

Witness: Ranie K. Wohnhas

REQUEST

AG_2_002

Refer to the Company's Response to the Attorney General's Initial RFI Question 1.d. State whether the PJM RTEP mandated the Supplemental portion of the project costs. Explain fully.

a. Identify and provide copies of any documents internal to KPCo and/or any of its affiliates which identify any Supplemental transmission projects slated for construction within: (i) KPCo's service territory, and (ii) any part of the Commonwealth of Kentucky not within KPCo's service territory.

b. Discuss the measures KPCo and/or any of its affiliates have taken to facilitate the timely and meaningful input and participation of customers and stakeholders in the development of transmission plans.

c. Discuss whether KPCo provided opportunity through PJM's Subregional RTEP Committee for stakeholders to review and comment on the criteria, assumptions, and models used with regard to the proposed project.

d. Provide any and all documentation indicating the measures KPCo and/or any of its affiliates have taken to ensure the project complies with FERC Order 890.

e. State whether KPCo and/or any of its affiliates have disclosed to all stakeholders the basic criteria, methodologies, assumptions, processes, and data that underlie the transmission plans of KPCo and/or its affiliates.

f. Discuss how this specific project, the Hazard-Wooton Line, fits into PJM's regional transmission planning process.

g. Provide either a web link to, or a hard copy of the Local Plan upon which KPCo and/or any of its affiliates are currently relying.

h. Confirm that the Local Plan KPCo and/or any of its affiliates are currently relying upon has been reviewed by a Subregional RTEP Committee.

i. Identify any and all meetings of the Subregional RTEP Committee, including location, times and places in which the proposed project, and any other KPCo Supplemental transmission projects scheduled anywhere within the Commonwealth of Kentucky were discussed and held open for comments of customers and stakeholders.

RESPONSE

a. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence. Documents related to projects undertaken by affiliates of Kentucky Power, and projects undertaken by Kentucky Power other than the Hazard-Wooton project, have no bearing on the subject matter of this proceeding, including the determination of the public convenience and necessity of the Hazard-Wooten project. Without waiving these objections, please refer to Exhibit 15 of the Application and KPCO_R_AG_2_2_Attachment1_Redacted.pdf for responsive documents relating to the Hazard-Wooton project. The Company further states that information about transmission projects in Kentucky Power's service territory and other areas in PJM Interconnection, L.L.C.'s ("PJM") footprint is publicly available from PJM's website.

b. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent the request requires an answer about projects other than the Hazard-Wooten project or projects involving entities other than Kentucky Power. Without waiving these objections, the Company states as follows:

Refer to the testimony of Company Witness Lasslo's testimony at pages 13-14 for a description of the PJM transmission planning process which includes review with stakeholders. In addition, as explained by Company Witness Larson at page 5 of her testimony an open house was held on August 24, 2017 at Hazard Community and Technical College to provide the general public the opportunity to offer comment and input on the Project and to gather additional information. The Company further solicited comment and questions from the public through the Fact Sheet attached as KPCO_R_AG_2_2_Attachment 2.pdf and its public website: kentuckypower.com/EKTP. Finally, Company representatives met with landowners, public officials, the Superintendent of the Hazard Independent School District, and the Hazard High School principal to solicit their input.

c. Kentucky Power complied with all applicable PJM Subregional RTEP Review Committee procedures. The Supplemental portion of the proposed project was presented November 2, 2017, and December 18, 2017, to stakeholders in two Subregional RTEP Committee meetings for review. The Baseline portion of the project was originally reviewed September 15, 2016, and October 6, 2016, through the Transmission Expansion Advisory Committee. In addition, the Hazard - Wooton Line, also was reviewed September 11, 2017, and November 2, 2017 with stakeholders through two additional Subregional RTEP Committee meetings.

d. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent the request purports to require an answer about projects other than the Hazard-Wooten project or projects involving entities other than Kentucky Power. Without waiving this objection, please refer to KPCO_R_AG_2_2_Attachment 3.pdf for slides that were reviewed by Kentucky Power with stakeholders through the appropriate Subregional RTEP Committee or Transmission Expansion Advisory Committee forums.

e. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent the request purports to require an answer about projects other than the Hazard-Wooten project or projects involving entities other than Kentucky Power. Without waiving this objection, Kentucky Power states it discloses basic planning assumptions with stakeholders at the beginning of every calendar year through Sub-Regional RTEP Committee meetings. Meeting materials can be found on the PJM Western Sub-Regional RTEP Committee website [http://www.pjm.com/committees-and-groups/committees/srrtep-w.aspx]. Please refer to KPCO_R_AG_2_2_Attachment 4.pdf for materials reviewed with stakeholders over the last two years.

f. Please refer to the testimony of Company Witness Lasslo at pages 10-12. Thermal violations were identified on the Hazard – Wooton 161 kV line as part of PJM's annual RTEP process in 2016. The specific project was approved as a baseline solution to the violations.

g. The Company objects to this data request on the grounds that the request is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent it purports to request information about projects other than the Hazard-Wooten project as described in the application or entities other than Kentucky Power Company.

Without waiving this objection, the Company states as follows: There is no discrete document identified as the 'Local Plan' as that term is defined in the PJM Operating Agreement. Thus, it is not possible to provide a copy or link. According to the PJM Operating Agreement, the Company's "Local Plan" shall include Supplemental Projects as identified by the Transmission Owners within their zone and Subregional RTEP projects developed to comply with all applicable reliability criteria, including Transmission Owners' planning criteria or based on market efficiency analysis and in consideration of Public Policy Requirements." The Hazard-Wooten project is part of the Company's 'Local Plan'; it has been identified by PJM to address Subregional RTEP Project needs and by Kentucky Power to address Supplemental Project needs, respectively.

h. The Company objects to this data request on the grounds that the request is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent it purports to request information about entities other than Kentucky Power Company. Without waiving this objection, Kentucky Power confirms the statement as it applies to the Company.

i. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent the request purports to require an answer about projects other than the Hazard-Wooten project. Without waiving this objection, Kentucky Power states that the Supplemental and Baseline aspects of the proposed project were reviewed with stakeholders at PJM headquarters and via telephone during Subregional RTEP Committee meetings on the following dates:

September 11, 2017
November 2, 2017
December 18, 2017

Baseline aspects of the proposed project were also reviewed with stakeholders at PJM headquarters and via telephone during Transmission Expansion Advisory Committee meetings on the following dates:
September 15, 2016
October 6, 2016

Witness: Michael G. Lasslo

PJM Submittal Slide

Hazard Station Rehab Work

Operating Company: KPCo

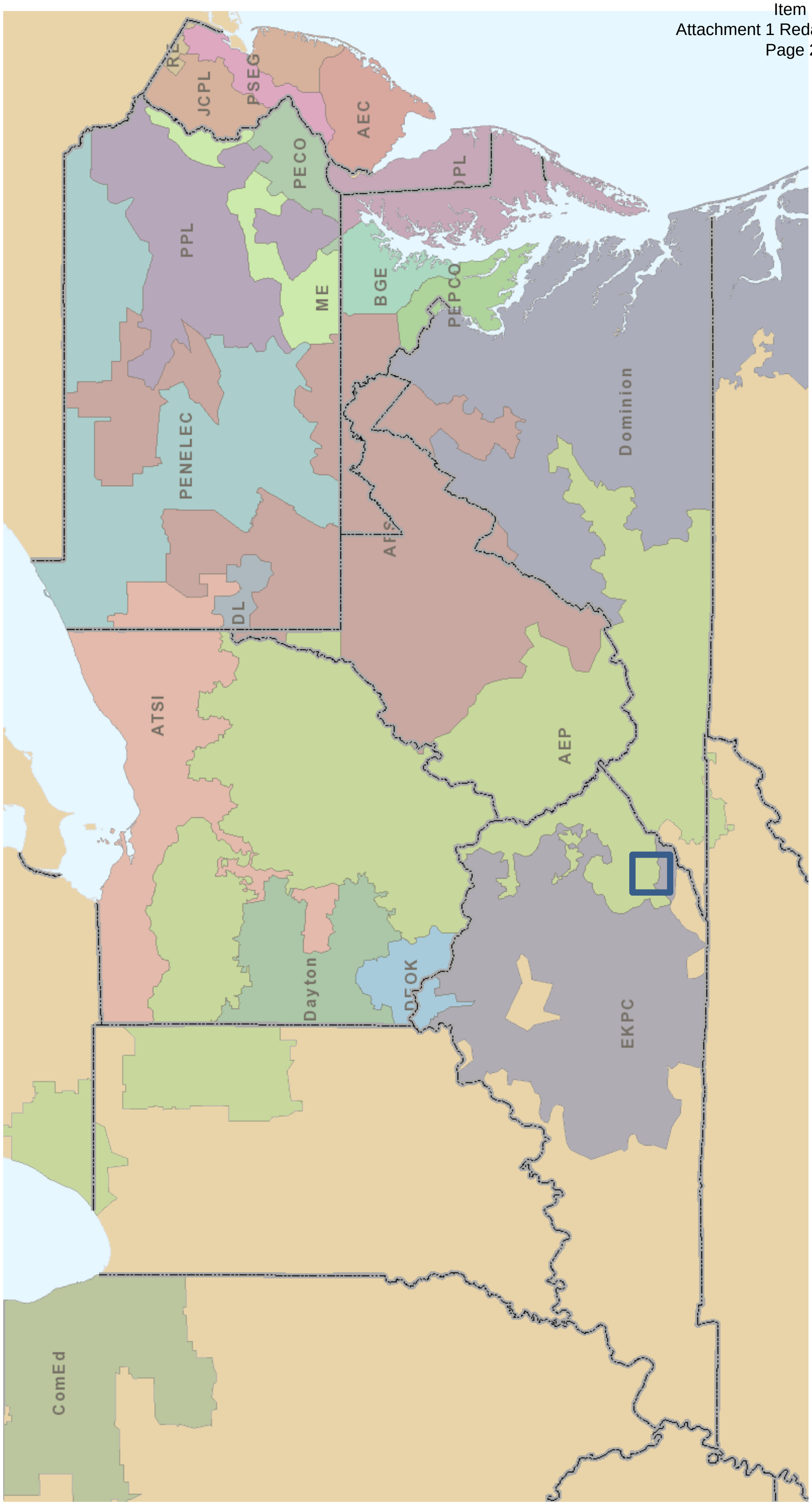
Project Type: Supplemental

Project Category: Equipment Material/Condition/Performance/Risk

Project Location: Hazard, KY
Estimated Total Cost: $20,000,000
Estimated Trans Cost: $20,000,000
Estimate Type: Class IV
Current Status: Scoping
Projected ISD: 12/31/2019
AEP Project Number(s): A15702041, TP2011063, TP2013064
PJM Project Number(s):
PLMP Risk Level: High

Project Sponsor:
Revision Date: 10/23/2017
Revision Number: 0
PJM Submission Date: 10/24/2017
SRRTEP/TEAC Date:

Project Location



PJM Submittal Slide

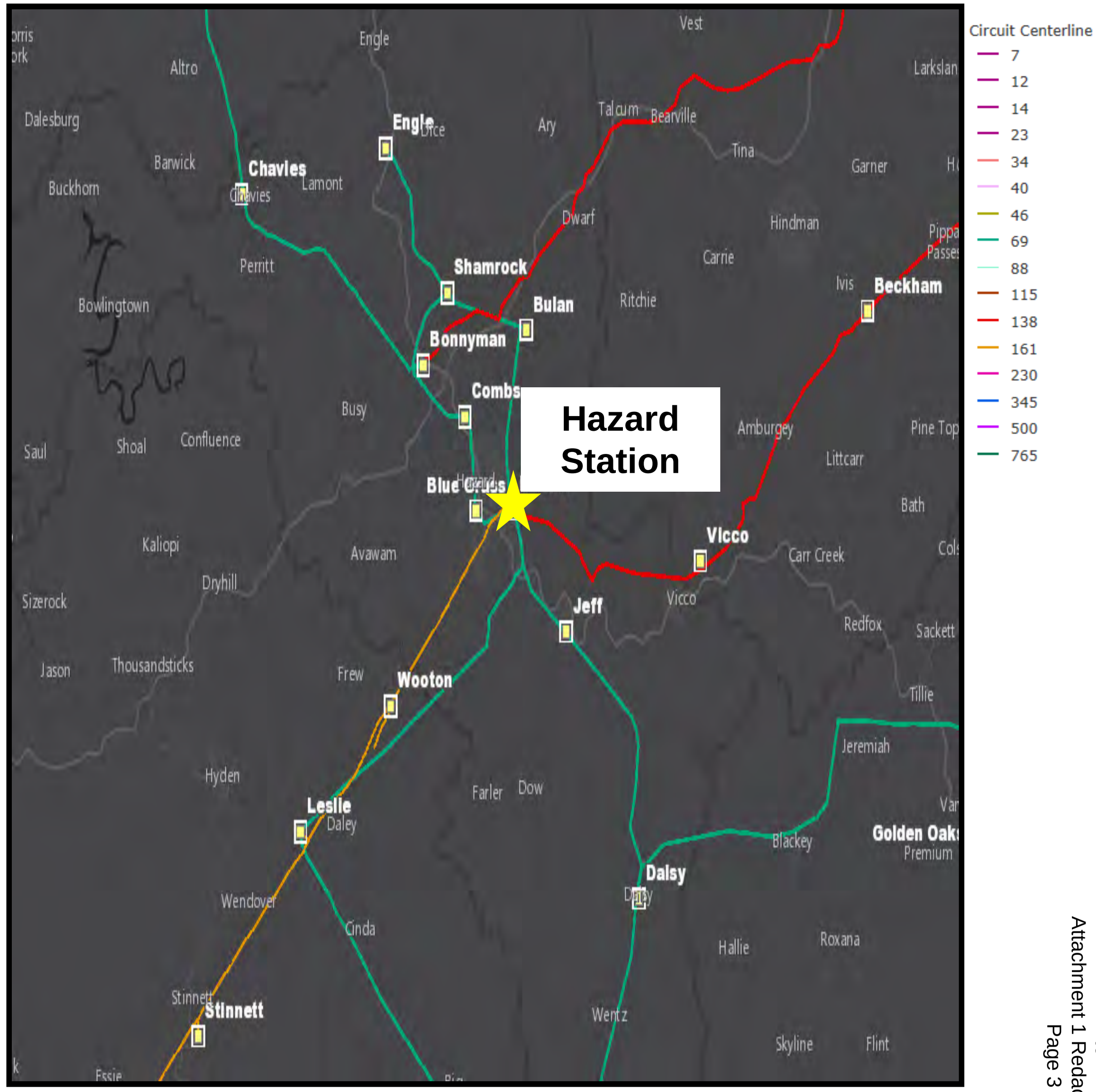
Project Description

Hazard Station: 1400 E. Main St, Hazard, KY

Hazard Station

Install a new 3000A 40 kA 138 kV circuit breaker at Hazard station on the line exit towards Beckham station. A 138 kV circuit switcher will be added to the high side of transformer #4. 138 kV capacitor bank and switcher BB will be replaced with a new switcher and 43.2 MVAR capacitor bank. 138/69 kV transformers #1 and #2 will be replaced by new 138/69 kV 130 MVA transformers with 138 kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side. 69 kV circuit breakers S, E, and F will be replaced with 3000A 40 kA 69 kV circuit breakers with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays. 69 kV capacitor bank and switcher CC will be replaced with a new switcher and 28.8 MVAR capacitor bank. 69 kV capacitor bank and switcher AA will be retired. 161 kV circuit breaker M towards Wooton will be replaced by a 161 kV 3000 A 40 kA breaker. A 3000A 40 kA 138 kV circuit breaker will be added to the low side of 161/138 kV transformer #3. Safety and access issues associated with existing equipment platforms and drainage issues at the station will also be addressed.

Estimated Transmission Cost: $20 M



Project Justification

Planning Criteria Violations:

N/A

Equipment Material/Condition/Performance/Risk:

Circuit breakers S and E at Hazard station are FK type breakers all over 40 years old. Circuit breaker F at Hazard is a CG type breaker. These are oil breakers that have come more difficult to maintain due to the required oil handling. In general, oil spills occur often during routine maintenance and failures with these types of breakers. Other drivers include PCB content, damage to bushings and number of fault operations exceeding the recommendations of the manufacturer. Breakers S, E, and F have experienced 82, 184, and 193 fault operations respectively, well above the manufactures recommendation of 10.

Circuit breaker M will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761). The breaker is 29 years old and has experienced 21 fault operations, which exceeds the manufacturer recommendation of 10.

Transformer #1 and #2 show dielectric breakdown (insulation), accessory damage (bushings/windings) and short circuit breakdown (due to amount of through faults). Transformer #1 also shows signs of corrosion on radiators as well as oil leaks.

Circuit Switcher BB a MARK V unit which have presented AEP with a large amount of failures and mis-operations. AEP has determined that all MARK V's will be replaced and upgraded with the latest AEP cap-switcher design standard. Capacitor bank BB will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761).

Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor bank CC was a non standard design and its components (fuses and cans) have begun to fail.

Safety concerns associated with existing equipment platforms at the station will also be addressed. The majority of the platforms at the station were field designed with thought of access, not safety, adequate clearances, or structural integrity in mind. Drainage issues at the station will also be addressed.

Operational Flexibility and Efficiency

A 138 kV circuit breaker will be added at Hazard station on the line exit towards Beckham station, along with a circuit switcher and low side breaker on transformer # 1 to separate three dissimilar zones of protection.

138 kV circuit switchers will be added to transformer #2 and #4, as well as low side breakers on transformer #2, #3, and #4 to separate four dissimilar zones of protection.
Transmission Operations has requested a 69 KV bus tie circuit breaker be installed to improve operational flexibility to the 69 kV networks served out of Hazard. The 69 kV tie breaker will also help facilitate the retirement of Capacitor AA which: is currently located off the line to Bonnyman, is beginning to show issues, and requires its VBM type cap switcher replaced.

Infrastructure Resilience:

N/A

Customer Service:

N/A

Other:

N/A

PJM Submittal Slide

Alternates Considered

Alternate #1

Rebuilding the station in the clear was evaluated. Lack of a suitable site in close proximity to the station due to the mountainous terrain and nearby population would have resulted in significant rerouting of the six transmission circuits and the four distribution circuits located within the existing station. It was determined that this would not be a cost effective alternative. Beyond the cost implications, relocation of the circuits and station would have been extremely challenging, if not infeasible, from a siting perspective.

Conceptual Cost: $35 million

Alternate #2

Constructing the 69 kV portion of the yard into a 69 kV ring bus was evaluated. It was determined that this alternative was not physically possible at the existing station site without extended outages. This alternative was determined to be not feasible due to constructability aspects.

System Electrical Diagram

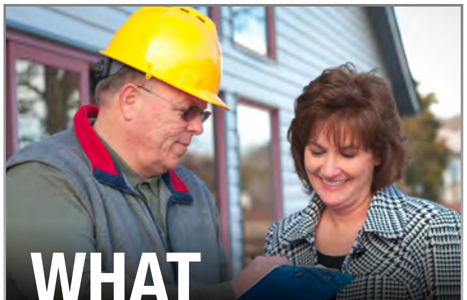
Pages 7 to 24 contain confidential critical energy infrastructure information ("CEII") and are redacted in their entirety.

7

Eastern Kentucky Transmission Program

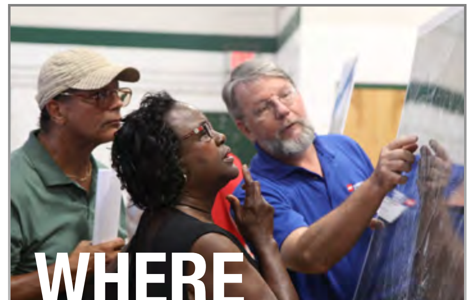
Hazard – Wooton Project

Kentucky Power plans to strengthen the power grid in eastern Kentucky by making upgrades to aging transmission infrastructure in Perry and Leslie counties. The Hazard - Wooton Project is the first project under the Eastern Kentucky Transmission Program. The project will rebuild approximately 7 miles of existing 161-kilovolt (kV) transmission line and make upgrades to other transmission facilities to ensure continue reliable electric service to customers. Construction for The Hazard – Wooton Project is expected to begin summer 2018 and be complete by fall 2019. Estimated budget for this phase is $30 million.



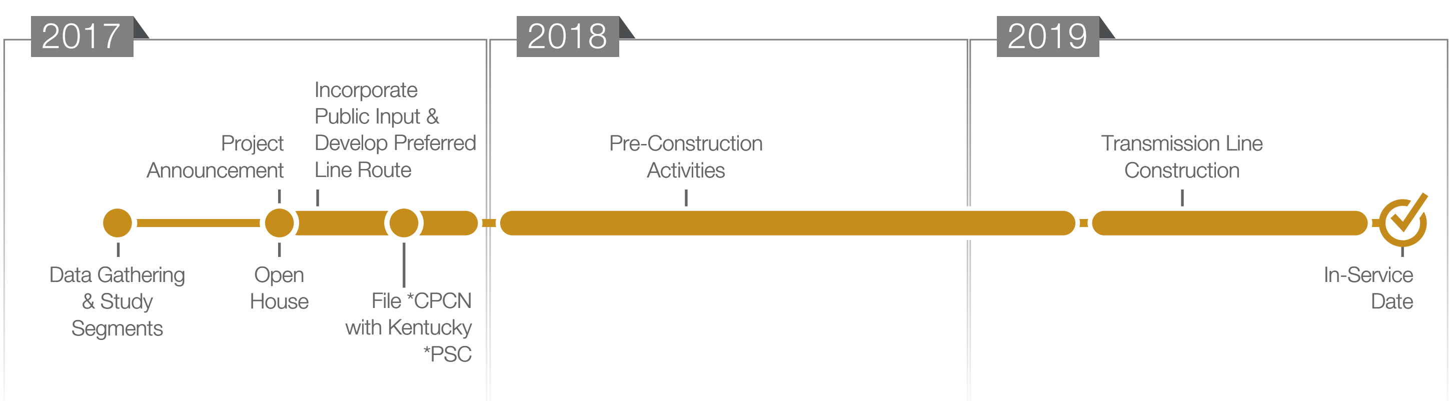
The Hazard - Wooton Project will rebuild approximately 7 miles of existing 161 kV transmission line and make upgrades to other transmission facilities. The project will provide the eastern Kentucky area with a reliable, resilient and robust transmission grid.

The existing Hazard-Wooton 161 kV transmission line was built nearly 80 years ago. Modernizing the line will help reinforce the local transmission grid, reduce the number of outages, and decrese restoration times when outages do occur.



The project starts at the Hazard Substation on East Main Street and continues west through Hazard along the ridge just north of Hazard High School. The line then continues southwest out of Hazard and connects with the substation on Wooton Creek Road.

Project Schedule*



*Project schedule is subject to change *CPCN represents Certificate of Public Convenience and Necessity *PSC represents Public Service Commission

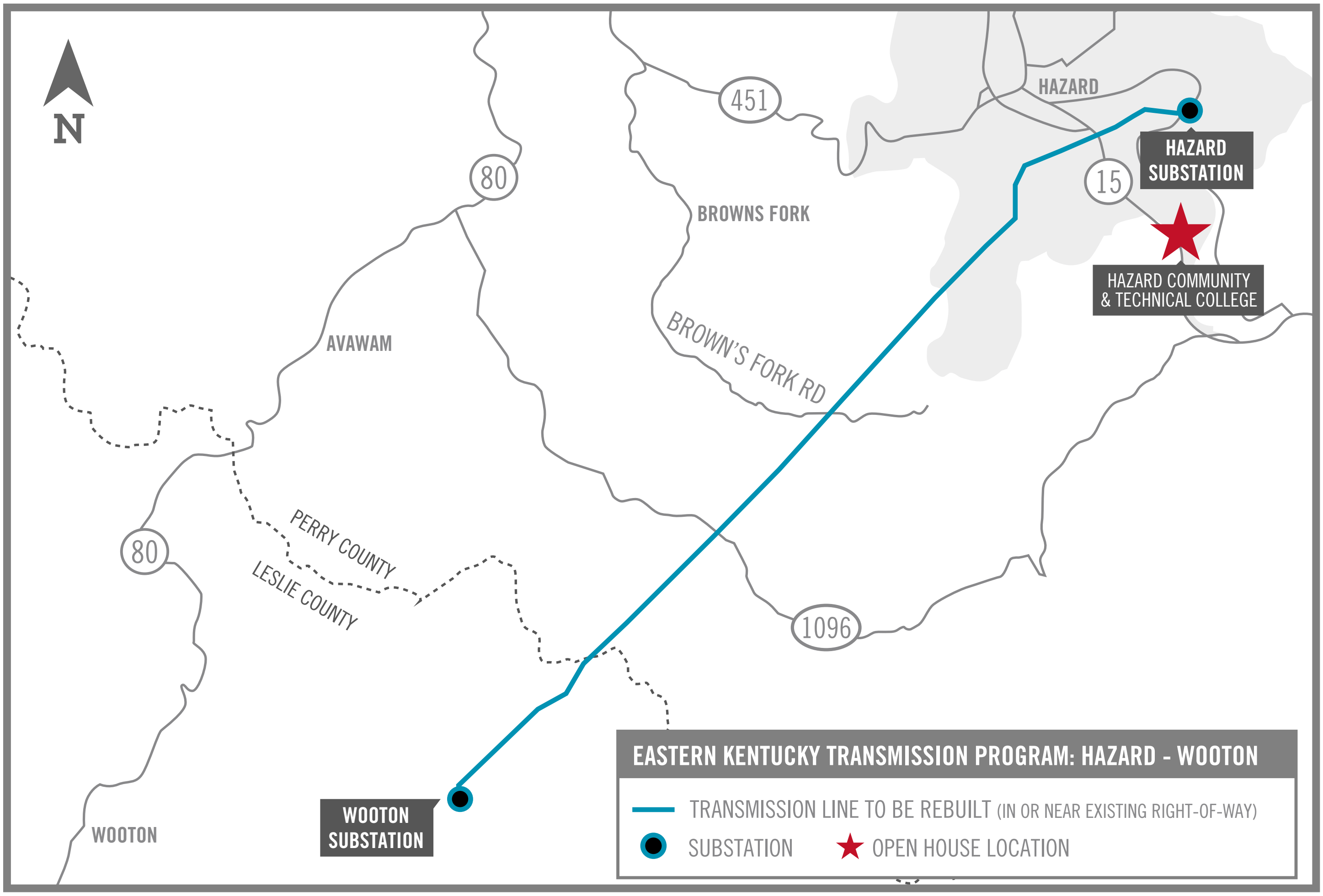
Typical Structures*

Structures along the route will be steel H-Frames and double circuit monopoles. Typical structures are about 90 feet tall. The typical right-of-way will be 120 feet wide.

Kentucky Power is committed to carefully balancing the energy needs of our customers while protecting the environment and natural beauty of the region.

*Exact structure, height and right-of-way width may vary

Project Map



Kentucky Power welcomes your feedback regarding this project. Please send comments and questions to:

Contact:

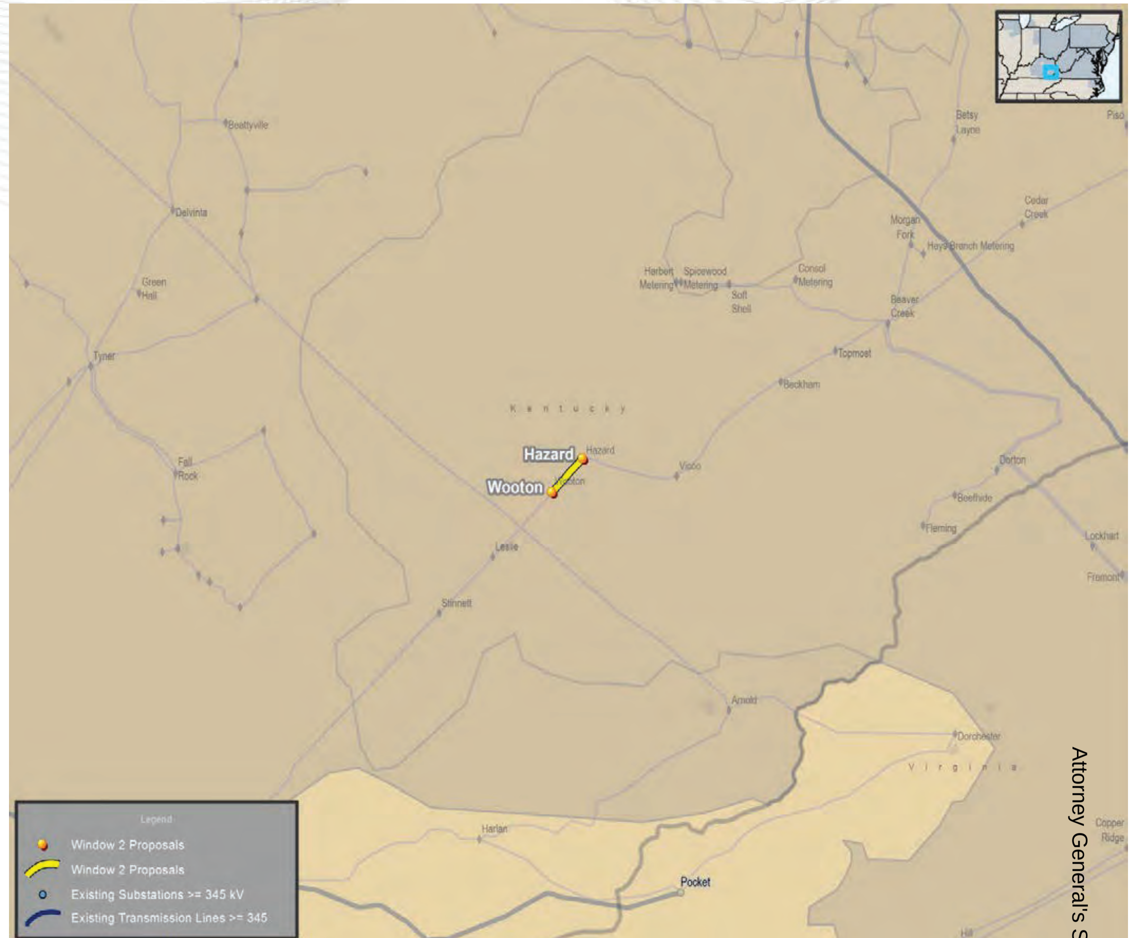
George Porter
Project Outreach Specialist
540-562-7092
gaporter@aep.com

If you have questions or need more information visit the project website at:
www.KentuckyPower.com/EKTP

KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY℠

AEP Transmission Zone

- Common Mode Outage (FG# 874, 875, 901, 902) :
- Hazard 161/138 kV transformer and Hazard to Wooton 138 kV circuit are overloaded for multiple 138 kV tower contingencies from Clinch River to Fremont/Lockhart to Dorton.
- **Alternatives considered:**
  - 2016_2-7A ($2.3 M)
  - 2016_2-7B ($10.45M)
- **Preliminary Recommendation:**
  - Replace Hazard XF / Sag Study Hazard – Wooton. (2016_2-7A)
- **Estimated Project Cost:** $ 2.3 M
- **Required IS Date:** 6/1/2021



AEP Transmission Zone

Common Mode Outage (FG# 874, 875, 901, 902):

- Hazard 161/138 kV transformer and Hazard to Wooten 138 kV circuit are overloaded for multiple 138 kV tower contingencies from Clinch River to Fremont/Lockhart to Dorton.

Alternatives considered:

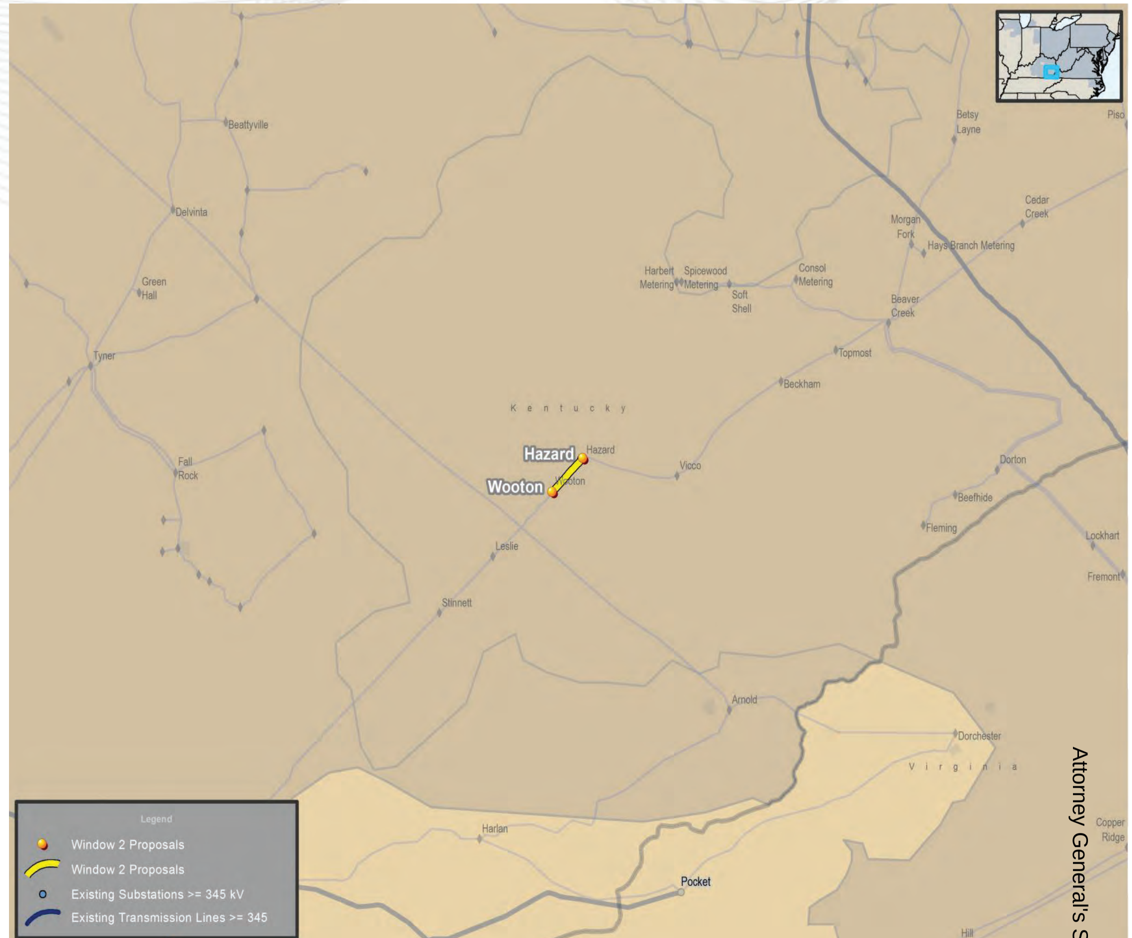
- 2016_2-7A ($2.3 M)
- 2016_2-7B ($10.45M)

Recommendation:

- Replace the Hazard 161/138 kV Transformer
- Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line. (b2761.1 - b2761.2)

Estimated Project Cost: $ 2.3 M

Required IS Date: 6/1/2021



AEP Transmission Zone

Baseline Reliability –Project Additional Scope

Problem Statement:

The Hazard – Wooton 161 kV line overloads under summer and winter peak conditions during generation deliverability analysis performed as part of the 2016 PJM RTEP Window 2. During the 2016 PJM RTEP Window 2, the recommended solution is "Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line" (B2761.2, presented on 10/6/2016 TEAC). The results of the sag study determined that 40 of the 45 structures which comprise the line would need to be replaced due to sag clearance issues. Additionally, approximately 6.3 of the 6.5 mile Hazard – Wooton 161 kV line utilizes wood structures from 1943. There are currently a total of 52 category A open conditions along the 6.5 mile long line which is comprised of 45 structures. These open conditions include damaged/rotted poles and damaged guy wires, shield wire, conductor, insulators, and cross arms. Therefore, the conclusion of the sag study is to rebuild the line.

Potential Solution:

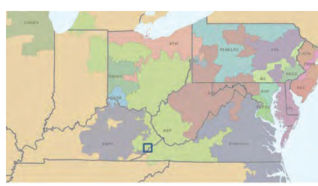
Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating).

Alternatives:

No feasible alternatives.

Estimated Project Cost: $16.48M

Required IS Date: 6/1/2021



AEP Transmission Zone: Baseline Hazard – Wooton 161kV Circuit

Baseline Reliability –Project Additional Scope
Previously Presented: 9/11/2017 SRTEAC

Problem Statement: The Hazard – Wooton 161 kV line overloads under summer and winter peak conditions during generation deliverability analysis performed as part of the 2016 PJM RTEP Window 2. During the 2016 PJM RTEP Window 2, the recommended solution is "Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line" (B2761.2, presented on 10/6/2016 TEAC). The results of the sag study determined that 40 of the 45 structures which comprise the line would need to be replaced due to sag clearance issues. Additionally, approximately 6.3 of the 6.5 mile Hazard – Wooton 161 kV line utilizes wood structures from 1943. There are currently a total of 52 category A open conditions along the 6.5 mile long line which is comprised of 45 structures. These open conditions include damaged/rotted poles and damaged guy wires, shield wire, conductor, insulators, and cross arms. Therefore, the conclusion of the sag study is to rebuild the line.

Recommended Solution: Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating). (B2761.3)

Estimated Cost: $16.48M

Expected In-service: 6/1/2021

AEP Transmission Zone: Supplemental Hazard Station

Problem Statement:

Equipment Material/Condition/Performance/Risk:

Circuit breakers S and E at Hazard station are FK type breakers all over 40 years old. Circuit breaker F at Hazard is a CG type breaker. These are oil breakers that have come more difficult to maintain due to the required oil handling. In general, oil spills occur often during routine maintenance and failures with these types of breakers. Other drivers include PCB content, damage to bushings and number of fault operations exceeding the recommendations of the manufacturer. Breakers S, E, and F have experienced 82, 184, and 193 fault operations respectively, well above the manufactures recommendation of 10.

Circuit breaker M will need to be relocated in association with the baseline project to replace the existing 161/138kV transformer at Hazard station (b2761). The breaker is 29 years old and has experienced 21 fault operations, which exceeds the manufacturer recommendation of 10.

Transformer #1 and #2 show dielectric breakdown (insulation), accessory damage (bushings/windings) and short circuit breakdown (due to amount of through faults). Transformer #1 also shows signs of corrosion on radiators as well as oil leaks.

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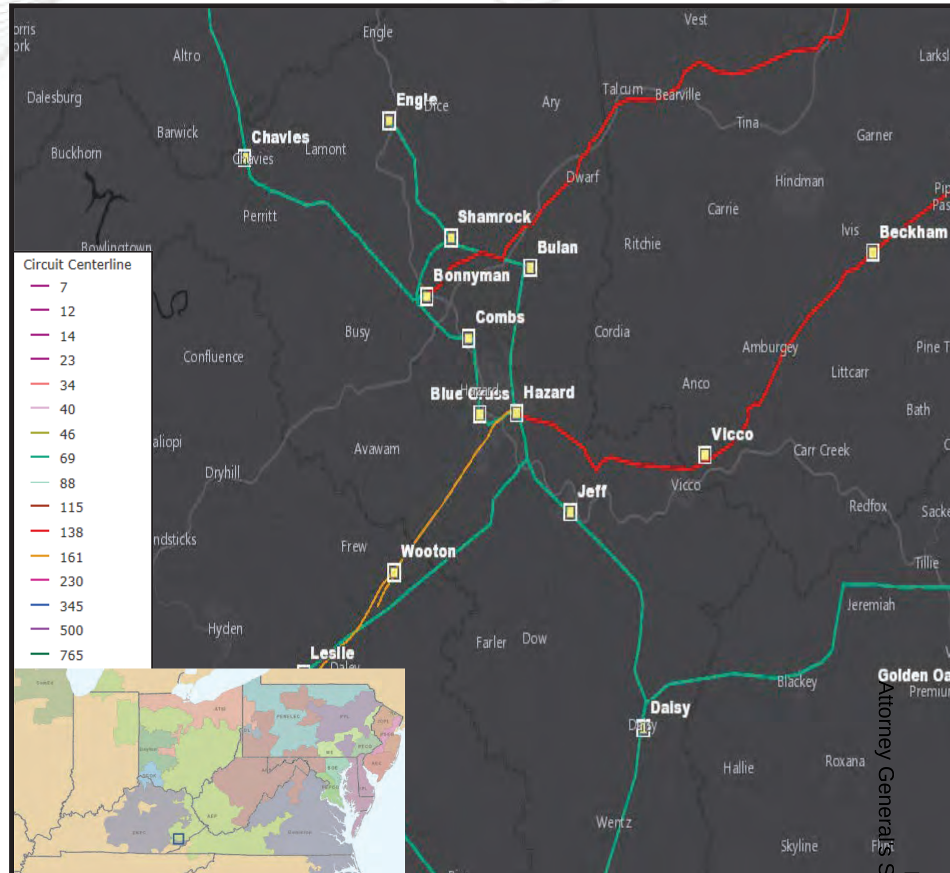

AEP Transmission Zone: Supplemental
Hazard Station

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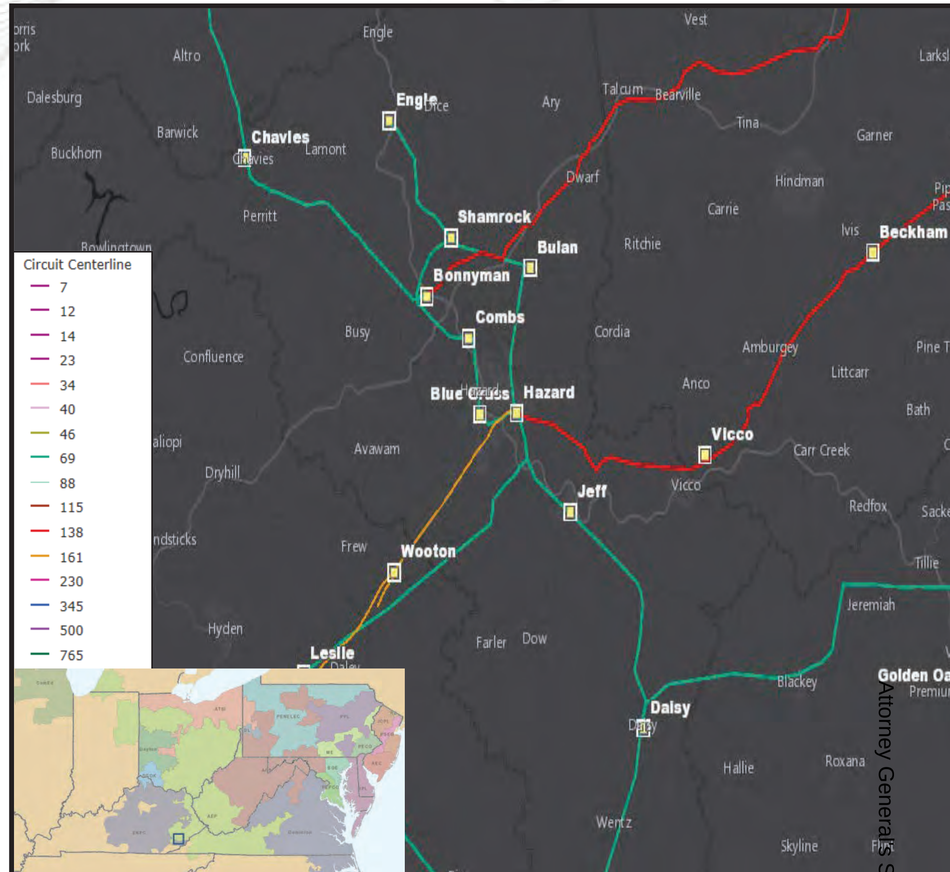
Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor bank CC was a non standard design and its components (fuses and cans) have begun to fail.

Safety concerns associated with existing equipment platforms at the station will also be addressed. The majority of the platforms at the station were field designed with thought of access, not safety, adequate clearances, or structural integrity in mind. Drainage issues at the station will also be addressed.

<u>Operational Flexibility and Efficiency</u>

A 138kV circuit breaker will be added at Hazard station on the line exit towards Beckham station, along with a circuit switcher and low side breaker on transformer # 1 to separate three dissimilar zones of protection.

138kV circuit switchers will be added to transformer #2 and #4, as well as low side breakers on transformer #2, #3, and #4 to separate four dissimilar zones of protection. Transmission Operations has requested a 69 KV bus tie circuit breaker be installed to improve operational flexibility to the 69 kV networks served out of Hazard. The 69 kV tie breaker will also help facilitate the retirement of Capacitor AA which: is currently located off the line to Bonnyman, is beginning to show issues, and requires its VBM type cap switcher replaced.



AEP Transmission Zone: Supplemental Hazard Station

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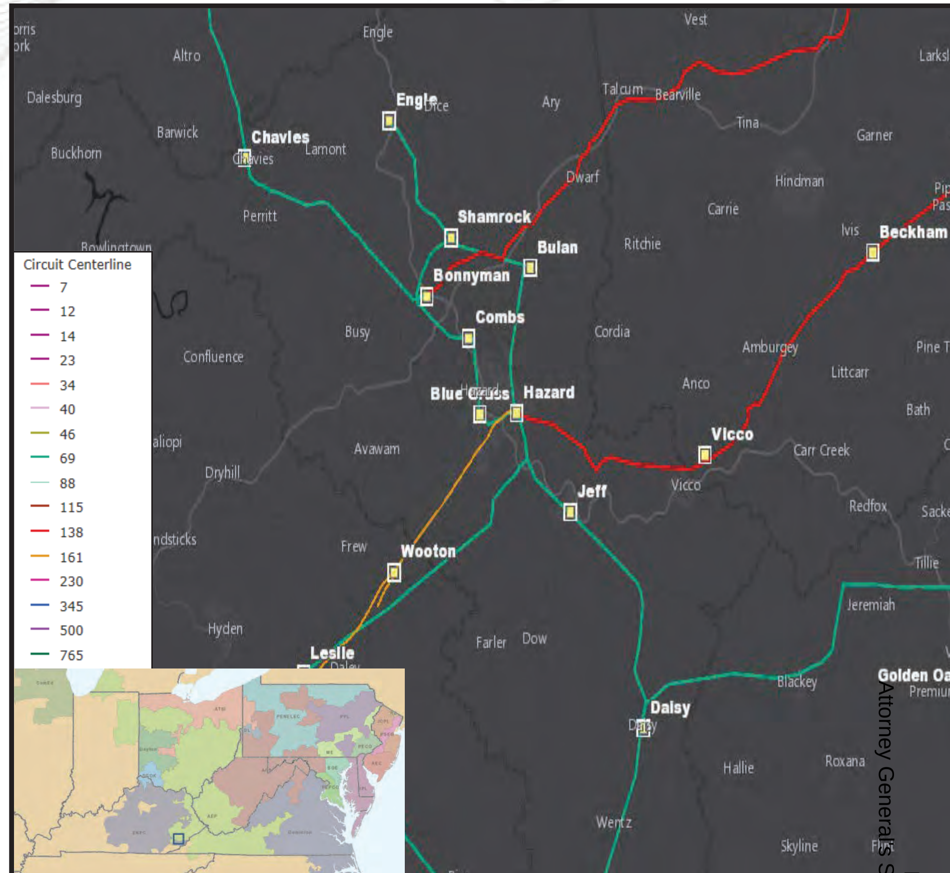
Potential Solution:

Install a new 3000A 40 kA 138kV circuit breaker at Hazard station on the line exit towards Beckham station. A 138kV circuit switcher will be added to the high side of transformer #4. 138kV capacitor bank and switcher BB will be replaced with a new switcher and 43.2 MVAR capacitor bank. 138/69 kV transformers #1 and #2 will be replaced by new 138/69 kV 130 MVA transformers with 138kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side. 69 kV circuit breakers S, E, and F will be replaced with 3000A 40 kA 69 kV circuit breakers with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays. 69 kV capacitor bank and switcher CC will be replaced with a new switcher and 28.8 MVAR capacitor bank. 69 kV capacitor bank and switcher AA will be retired. 161 kV circuit breaker M towards Wooton will be replaced by a 161 kV 3000 A 40 kA breaker. A 3000A 40 kA 138kV circuit breaker will be added to the low side of 161/138kV transformer #3. Safety and access issues associated with existing equipment platforms and drainage issues at the station will also be addressed.

Estimated Transmission Cost: $20.0M



AEP Transmission Zone: Supplemental Hazard Station

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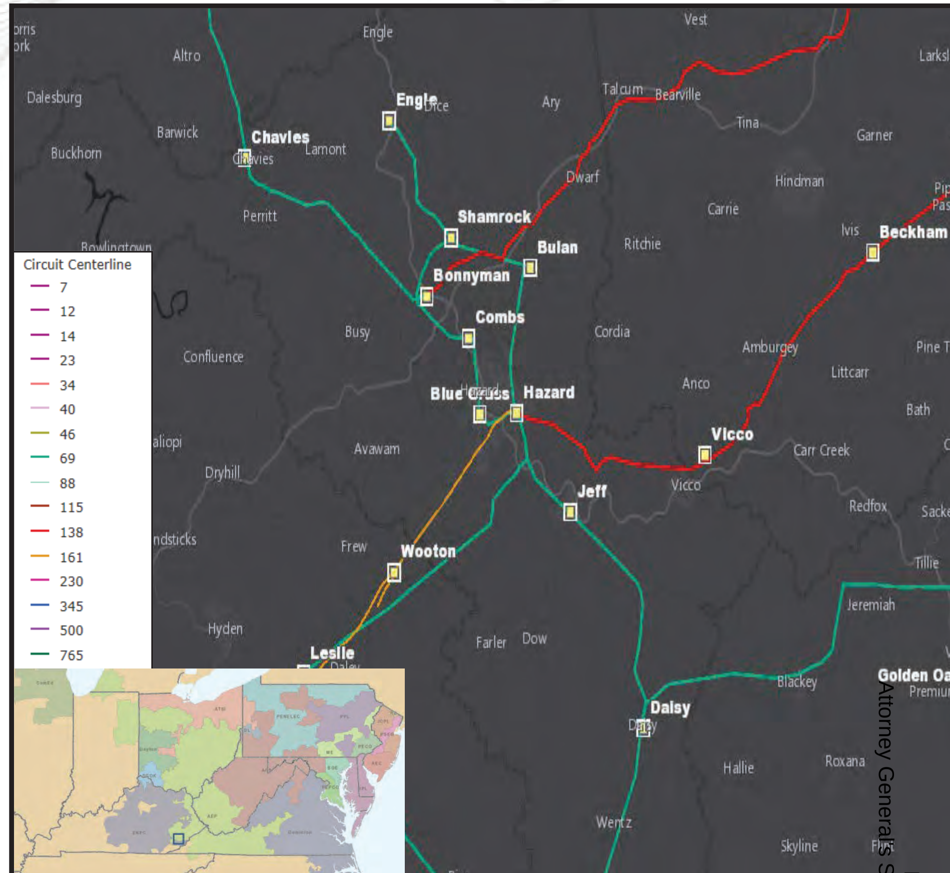
Alternatives:

- Rebuilding the station in the clear was evaluated. Lack of a suitable site in close proximity to the station due to the mountainous terrain and nearby population would have resulted in significant rerouting of the six transmission circuits and the four distribution circuits located within the existing station. It was determined that this would not be a cost effective alternative. Beyond the cost implications, relocation of the circuits and station would have been extremely challenging from a siting perspective. **Estimated Cost: $35M**
- Constructing the 69 kV portion of the yard into a 69 kV ring bus was evaluated. It was determined that this alternative was not physically possible at the existing station site without extended outages. This alternative was determined to be not feasible due to constructability aspects.

Projected In-service: 12/31/2019

Project Status: Scoping



AEP Transmission Zone: Supplemental Hazard Station

Previously Presented: 11/2/2017 SRRTEP

Problem Statement:

Equipment Material/Condition/Performance/Risk:

Circuit breakers S and E at Hazard station are FK type breakers all over 40 years old. Circuit breaker F at Hazard is a CG type breaker. These are oil breakers that have come more difficult to maintain due to the required oil handling. In general, oil spills occur often during routine maintenance and failures with these types of breakers. Other drivers include PCB content, damage to bushings and number of fault operations exceeding the recommendations of the manufacturer. Breakers S, E, and F have experienced 82, 184, and 193 fault operations respectively, well above the manufactures recommendation of 10.

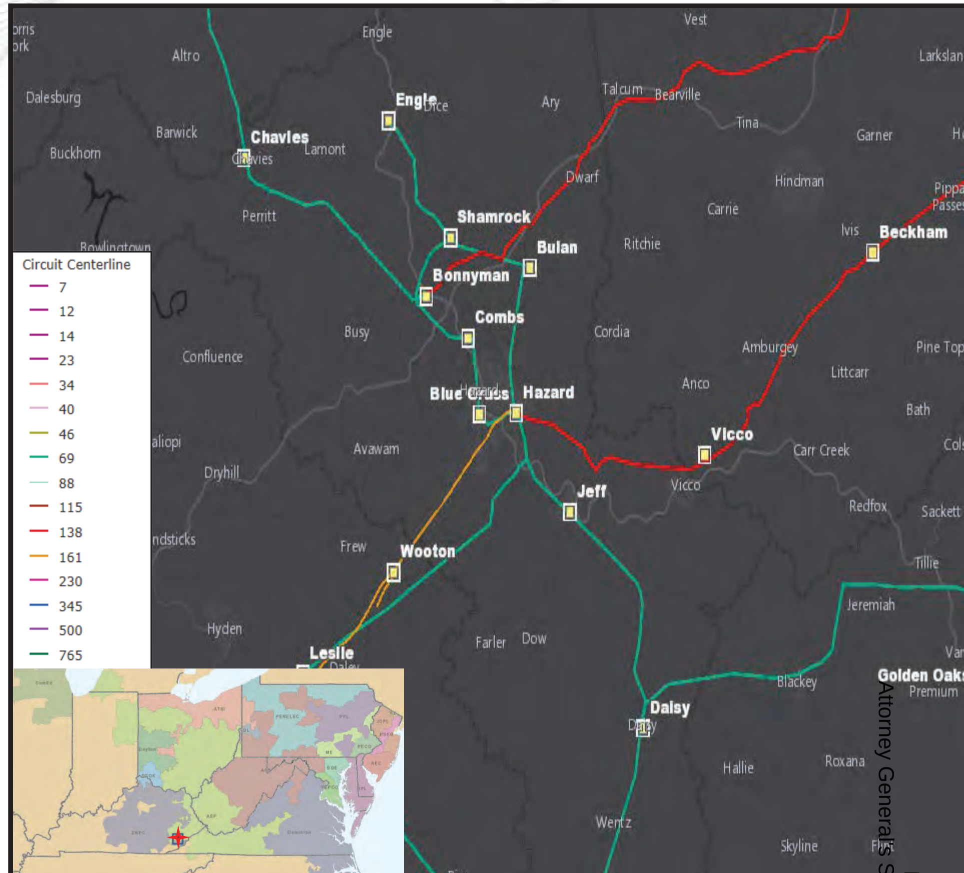
Circuit breaker M will need to be relocated in association with the baseline project to replace the existing 161/138kV transformer at Hazard station (b2761). The breaker is 29 years old and has experienced 21 fault operations, which exceeds the manufacturer recommendation of 10.

Transformer #1 and #2 show dielectric breakdown (insulation), accessory damage (bushings/windings) and short circuit breakdown (due to amount of through faults). Transformer #1 also shows signs of corrosion on radiators as well as oil leaks.

Circuit Switcher BB a MARK V unit which have presented AEP with a large amount of failures and mis-operations. AEP has determined that all MARK V's will be replaced and upgraded with the latest AEP cap-switcher design standard. Capacitor bank BB will need to be relocated in association with the baseline project to replace the existing 161/138kV transformer at Hazard station (b2761).

Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor bank CC was a non standard design and its components (fuses and cans) have begun to fail.

Safety concerns associated with existing equipment platforms at the station will also be addressed. The majority of the platforms at the station were field designed with thought of access, not safety, adequate clearances, or structural integrity in mind. Drainage issues at the station will also be addressed.



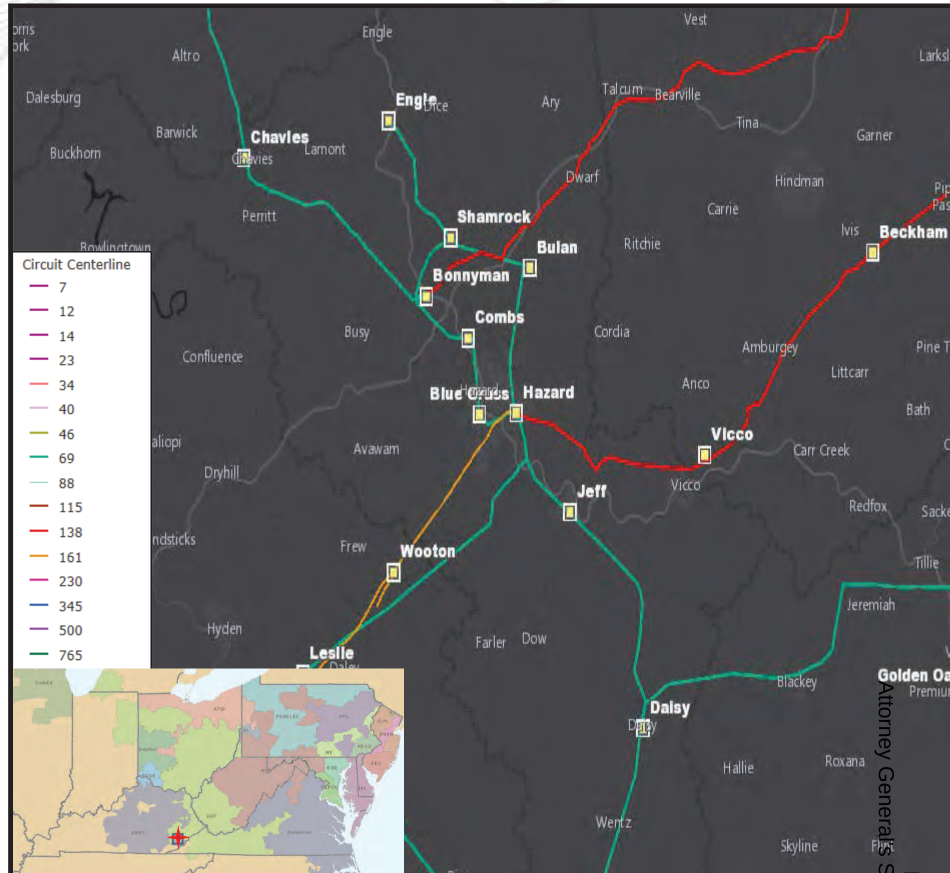
AEP Transmission Zone: Supplemental Hazard Station

Continued from previous slide…

Operational Flexibility and Efficiency

A 138kV circuit breaker will be added at Hazard station on the line exit towards Beckham station, along with a circuit switcher and low side breaker on transformer # 1 to separate three dissimilar zones of protection.

138kV circuit switchers will be added to transformer #2 and #4, as well as low side breakers on transformer #2, #3, and #4 to separate four dissimilar zones of protection.
Transmission Operations has requested a 69 KV bus tie circuit breaker be installed to improve operational flexibility to the 69 kV networks served out of Hazard. The 69 kV tie breaker will also help facilitate the retirement of Capacitor AA which: is currently located off the line to Bonnyman, is beginning to show issues, and requires its VBM type cap switcher replaced.



AEP Transmission Zone: Supplemental
Hazard Station

Continued from previous slide…

Selected Solution:

Install a new 3000A 40 kA 138kV circuit breaker at Hazard station on the line exit towards Beckham station.

Add a 138kV circuit switcher to the high side of transformer #4 at Hazard station. **(S1412.1)**

Replace 138kV capacitor bank and switcher BB with a new switcher and 43.2 MVAR capacitor bank at Hazard station. **(S1412.2)**

Replace 138/69 kV transformers #1 and #2 with new 138/69 kV 130 MVA transformers with 138kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side at Hazard station. **(S1412.3)**

Replace 69 kV circuit breakers S, E, and F with 3000A 40 kA 69 kV circuit breakers and with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays at Hazard station. **(S1412.4)**

Replace 69 kV capacitor bank and switcher CC with a new switcher and 28.8 MVAR capacitor bank and retire the 69 kV capacitor bank and switcher AA at Hazard station. **(S1412.5)**

Replace the 161 kV circuit breaker M towards Wooton with a 161 kV 3000 A 40 kA breaker. **(S1412.6)**

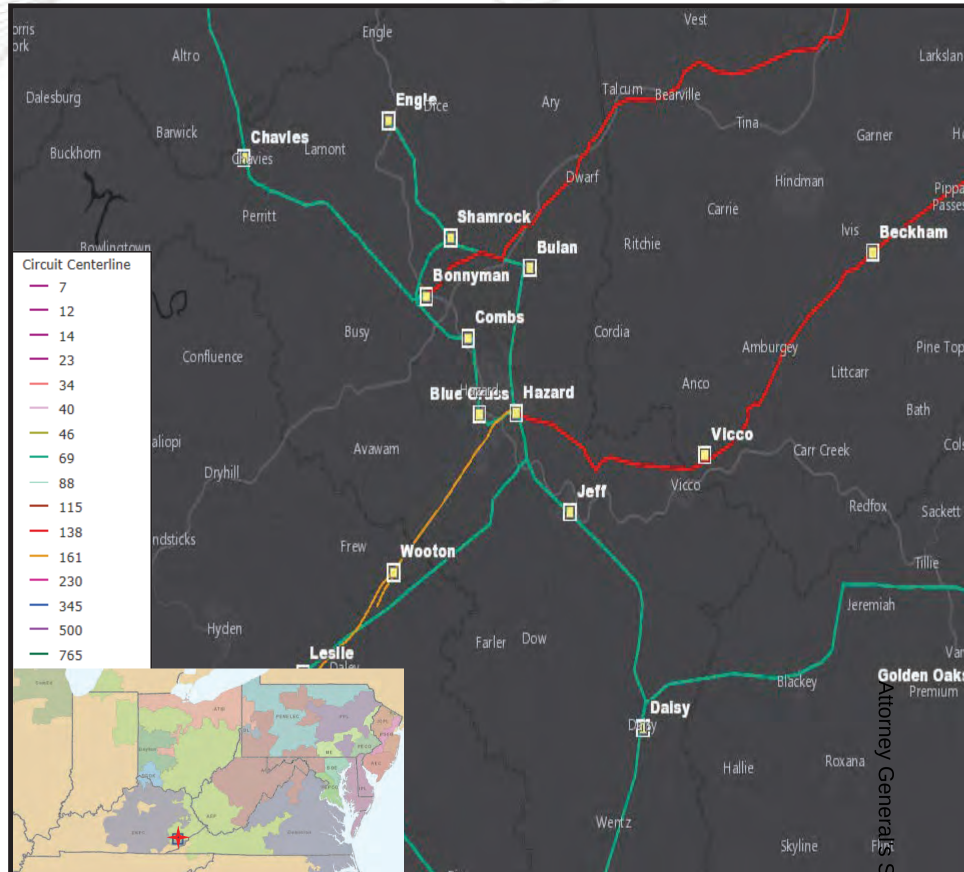
Add a 3000A 40 kA 138kV circuit breaker to the low side of 161/138kV transformer #3 at Hazard station. **(S1412.7)**

Address Safety and access issues associated with existing equipment platforms and drainage issues at the station at Hazard station. **(S1412.8)**

Estimated Transmission Cost: $20.0M

Projected In-service: 12/31/2019

Project Status: Scoping



AEP Guidelines for Transmission Owner Identified Needs

January 2017

Document Control

Document Review and Approval

Action	Name(s)	Title
Prepared by:	Ryan C. Dolan	Senior Engineer, Asset Performance and Renewal
Prepared by:	Kevin Killingsworth	Principal Engineer, Asset Performance and Renewal
Prepared by:	Jomar M. Perez	Supervisor, Asset Performance and Renewal
Reviewed by:	Jon Staninovski	Manager, Asset Performance and Renewal
Approved by:	Carlos J. Casablanca	Director, Advanced Transmission Studies and Technology
Approved by:	Kamran Ali	Director, East Transmission Planning
Approved by:	Wayman L. Smith	Director, West Transmission Planning

Review Cycle

Quarterly	Semi-annual	Annual	As Needed
		X	X

Revision History

Version	Revision Date	Changes	Comments
1.0	01/04/2017	N/A	1st Release

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 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, quantify, and prioritize needs associated with transmission facilities comprising AEP's system. Prioritization, in particular, becomes a critical element when determining how to utilize a finite set of financial, human and material resources needed to address a continuously expanding set of needs. 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, it describes the methodology applied to prioritize those 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.

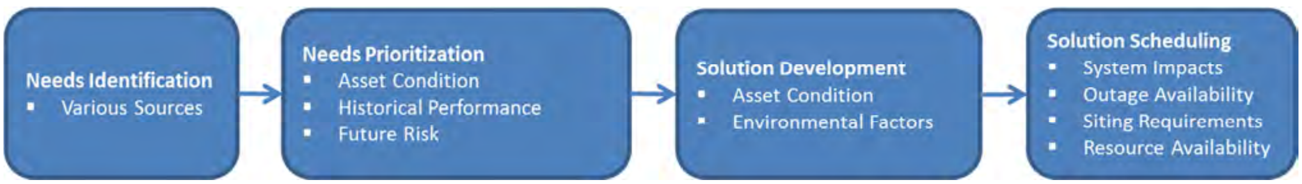
Addressing these owner identified transmission system needs will result in the following benefits:

- 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 and prioritization guidelines are used for projects that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. AEP uses the four (4) 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. 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 misoperation; Voltage unbalance
	Legacy system configurations	Ground switch protection schemes for transformers; Transmission line taps without switches; Equipment with no parts or no longer supported by vendors
	Outage duration and frequency	Outages resulting from equipment failures, misoperation, 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
	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
	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

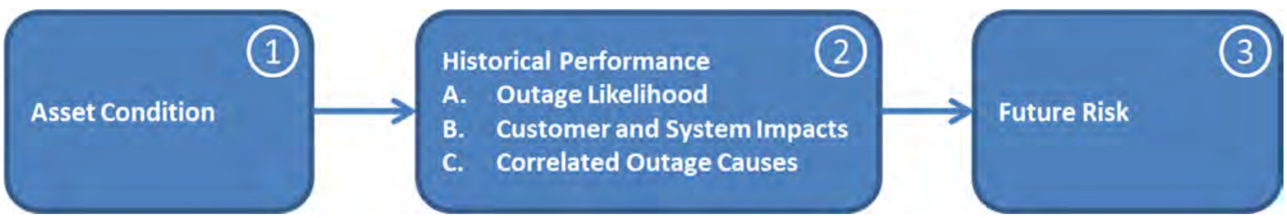
This information is reviewed and analyzed to identify the transmission assets that are not performing properly or are preventing the proper operation of the transmission system.

4.0 Step 2: Needs Prioritization

4.1 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, and Good Utility Practices that were applicable at the time of installation and have been exposed to varying operating conditions over their life. Due to the size, scope and age of the AEP system, as well as the evolution of standards and Good Utility Practices, the Needs Identification step results in a significant number of transmission assets with needs. Needs that have a direct safety concern are automatically placed at the top of the prioritized list and completed with the highest urgency. In prioritizing the needs that do not have a direct safety concern AEP uses a prioritization methodology that incorporates three key factors: Asset Condition, Historical Performance, and Future Risk (see Figure 2).

Figure 2 – Transmission Line and Station Prioritization Methodology



This methodology allows AEP to determine which asset needs will be most impactful to overall grid performance and service to customers so that solutions can be identified within the appropriate time frames. It implements a weighted total approach where assets are split by voltage class, which ensures the appropriate ranking of transmission line and station assets within each of AEP's operating companies. It is AEP's strategy to develop and provide the most efficient, cost-effective, and holistic long-term solutions for the identified needs.

4.2 Data Considerations

AEP generally uses three years of historical performance data, along with present day condition data, to perform the Needs Prioritization. In addition, a five-year risk assessment forecast is developed. For situations and assets deemed to present larger risks to the system, or to develop more forward looking plans, AEP may use more than three years of historical data and may also develop risk assessment forecasts beyond the five-year period.

AEP collects numerous impact indices to perform the Historical Performance and the projected Future Risk portions of the prioritization methodology, as well as to calculate the impact on a historical outage or a projected future outage basis. The key indices considered in this analysis include:

- Affected load (in MW)
- Number of customers interrupted
- Customer minutes of interruption

Additional “optional” impacts may be recorded and considered based upon data availability. The “optional” considerations are covered in greater detail in Section 4.4.2.

4.3 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 current condition of the asset or group of assets on the AEP system. This asset condition information is quantified into a future probability of failure adder which is added to the historical probability of failure recorded in the Historical Performance portion of the Needs Prioritization process. This approach accounts for an asset’s deterioration due to age, weather exposure, electrical system stresses, etc. The future probability of failure adder and the process used to quantify these values are unique to the asset or group of assets under consideration.

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 in the future probability of failure adder. Typically, assets that are no longer supported by manufacturers have a higher probability of failure adder.

4.4 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. AEP calculates two distinct sets of metrics to quantify Historical Performance: Outage Probability and Impacts. The historical outage probability data recorded during the Historical Performance assessment is used as the baseline outage probability applied during the Future Risk portion of the three-part prioritization assessment process.

The baseline historical outage probability is uniquely defined depending on the transmission asset under review. For transmission line and station facilities, historical outage probabilities are established by tracking and quantifying four distinct data points:

- Transmission System Average Interruption Duration Index (T-SAIDI)
- Transmission System Average Interruption Frequency Index (T-SAIFI)
- Transmission System Average Sustained Interruption Frequency Index (T-SAIFI-S)
- Transmission Momentary Average Interruption Index (T-MAIFI)

For large transmission station equipment such as circuit breakers, transformer and reactors, AEP's Asset Health Center Platform, which calculates the probability of failure associated with individual major pieces of equipment on the AEP transmission system, is used to obtain baseline outage probabilities.

A standard set of impact indices are used to quantify the historical impacts of an asset or group of assets. These historical impacts will be similar to future risk impacts used in the future risk of failure portion of the three-part prioritization assessment. Historical impacts include load loss, customer minutes of interruption, and number of customers interrupted.

4.4.1 Historical Performance: Outage Likelihood (Factor 2-A)

This review investigates an asset's three year historical performance with regards to its contribution to its associated voltage class's outage frequency and duration totals. Four transmission historical system performance metrics, as specified in Table 2, are calculated to quantify an operating company's three year historical performance levels on a voltage class basis and an individual asset's contribution to the identified voltage classes: T-SAIFI, T-MAIFI, T-SAIFI-S and T-SAIDI. 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 prioritization process, thus allowing for the proper identification and solution development for each operating company area.

Table 2 - Transmission Asset Performance Metrics

System Metric	Performance by Voltage Class	Application
T-SAIDI	Duration of all outages divided by total number of circuits in voltage class	Probability of a one hour outage
T-SAIFI	Number of outages divided by total number of circuits in voltage class	Probability of an outage
T-SAIFI-S	Number of sustained outages divided by total number of circuits in voltage class	Probability of an outage lasting more than five minutes
T-MAIFI	Number of momentary outages divided by total number of circuits in voltage class	Probability of an outage lasting less than five minutes

4.4.2 Historical Performance: Customer and System Impacts (Factor 2-B)

Historical impacts are divided into two sub-categories: customer impacts and system impacts. The customer impacts portion is defined by four metrics: IEEE SAIDI, IEEE CAIDI, IEEE SAIFI, and Loss of Load. These metrics are calculated using historical outage data that resulted directly from transmission line or station asset outages and are calculated separately for each asset class. All outage data pertaining to distribution line failures are removed from the data set in order to ensure accurate representation of customer impacts related to transmission line or station outages within the AEP transmission system. Additionally, all customer minutes of interruption occurring during severe weather events are removed from the analysis.

AEP also includes consideration to retail customers that are served by the parent wholesale customer service points. In order to account for customers served behind wholesale meter points, AEP gathers that 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 each individual customer's minutes of interruption and frequency. After compiling each asset's three year impact on Customer Minutes of Interruption, Customer Interruptions, and Loss of Load, AEP calculates the IEEE SAIDI, IEEE SAIFI, IEEE CAIDI and total loss of load for each region's three year system totals. Similar to Factor 2-A, each asset's contribution to its corresponding system totals are calculated to determine its percentage contribution to aggregated system totals.

When available, the data outlined in Table 3 will be collected for each outage on the AEP transmission system. Due to the limited availability of this information, these data points are considered "optional" in the needs prioritization process and are considered in the analysis on a case-by-case basis.

Table 3 - Optional System Impact Metrics (collected when data is available)

Optional Impact Indices	Quantifiable Value
Expected energy not delivered by failed component	Average energy flowing through equipment times expected outage duration
Generation loss	MW and MVAR range of units
Static reactive devices interrupted	MVAR
Dynamic reactive devices	MVAR range of devices interrupted
Number of stations with voltage sags	Number of EHV, HV, Sub-T stations
Number of tie line interconnections interrupted	Number of interrupted lines
Arming of SPS schemes due to stability or thermal constraints	Number of times a SPS is armed due to facility outage or projected outage
Number of real time operational constraints resulting load drop warnings	Number of times RTO issues load drop warnings associated with the projected outage of an asset

4.4.3 Historical Performance: Correlated Outage Causes (Factor 2-C)

Each transmission facility identified through the prioritization process outlined in Factors 2-A and 2-B will be subjected to a detailed investigation of the primary contributing cause of that facility's outage totals. 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 outages are quantified on frequency and duration totals with respect to these five categories. A value-based weighting will be assigned to a transmission asset. This value is used to determine if there is correlation between an asset's outage history and the failure of its associated components.

4.5 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 a long-term outage scenario and is based on the reported condition of the asset and the severity of that condition. It is calculated by summing the historical probability of failure, with the probability of failure due to future deterioration of an asset and then multiplying this calculated value by the quantified future impacts.

5.0 Step 3: Solution Development

The development of solutions for the identified needs considers a holistic view of all of the prioritized 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. 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.

6.0 Step 4: Solution Scheduling

Once solutions are developed to address the identified and prioritized 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.

7.0 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, it describes the methodology applied to prioritize the needs of different assets, 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.

8.0 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/

AEP Transmission
Local Plan Development

PJM Sub-regional RTEP
Western Meeting

January 5, 2017

Introduction to AEP

- **AEP is among the largest electric utilities in the United States**
  - More than 5 million customers
  - 200,000 + sq. mi service territory
  - 32 GW of generating capacity
  - Over 40,000 miles of electric transmission lines
  - More than 3500 substations
  - 215,000 miles of electric distribution lines

- **Largest owner of electric transmission in the United States**
  - Own, operate and maintain transmission facilities in 3 RTO s and 11 states
  - Interconnection with 60 major utilities across the U.S.
  - Supplying ~10% of demand in Eastern Interconnection and ~11% of demand in ERCOT

AEP Zone in PJM

- Total AEP Transmission facilities in PJM region: ~23,000 miles

765 kV	~2,200 miles
500 kV	~100 miles
345 kV	~4,000 miles
230 kV	~100 miles
161 kV	~50 miles
138 kV	~9,000 miles
Sub-T	~8,000 miles

- Connected demand modeled in AEP Transmission zone in PJM

	2022 Summer	2022/23 Winter
Appalachian	6,447 MW	7,228 MW
Indiana Michigan	4,863 MW	4,321 MW
Kentucky	1,170 MW	1,401 MW
Ohio	11,425 MW	10,127 MW
Total	**23,905 MW**	**23,077 MW**

- AEP load in the RTEP case is scaled to PJM forecast.

3

PJM Power Flow Models

- AEP supports development of and updates to RTEP cases.

- AEP participates in development of annual series of ERAG MMWG base cases.
  - Cases include seasonal, near-term, and long-term models used in ERAG and RFC assessments of the Transmission system.

- AEP planning studies utilize available PJM RTEP cases.
  - AEP has both summer and winter peaking zones.
  - Internal cases are developed, on case by case basis, to represent and address local historic constraints observed in real-time.

AEP Planning Criteria – FERC 715

- AEP transmission system is planned in adherence with NERC TPL-001-4 and PJM Planning Criteria outlined in Manual 14B.
- AEP Planning Criteria (FERC 715) aligns with NERC and RTO planning criteria.
  - Also includes criteria to plan non-BES system below 100 kV.
- All planning studies utilize the latest available PJM RTEP cases.
- PJM evaluates compliance and adherence to above standards and criteria from regional perspective (top down), and AEP does the same from a local perspective (bottom up).

Link to AEP FERC 715:
https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/AEP_East_FERC_715_2016_Final_Part_4.pdf

Customer Interconnections

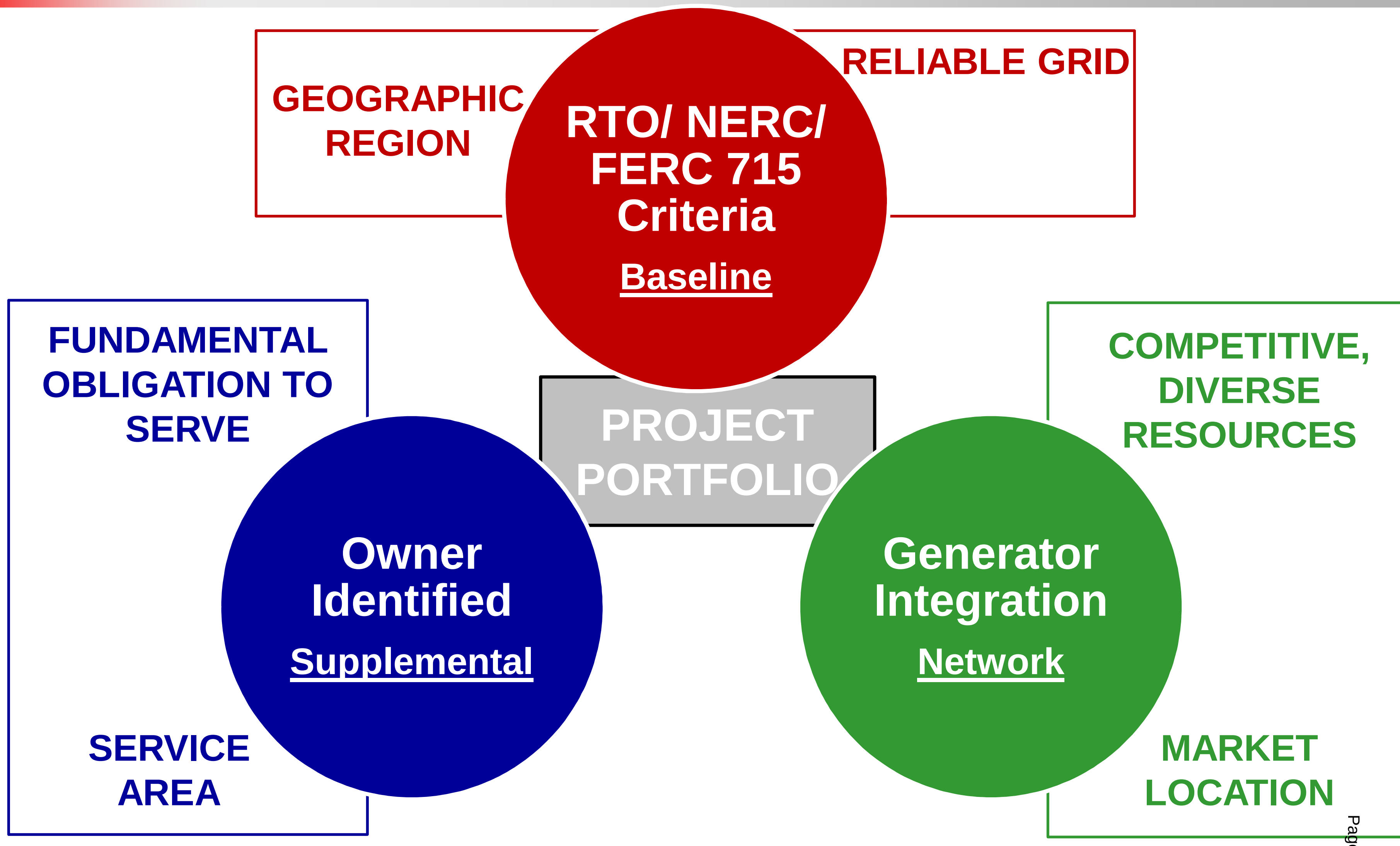
- In accordance with NERC Standard FAC-001-2, AEP has posted requirements for interconnections of end-use customers, generators, and transmission facilities.

- To provide service to end-use customers, AEP performs initial studies to determine the system impacts and develop a plan of service for contracted load levels.
  - Required transmission upgrades are validated by PJM under baseline reliability criteria.

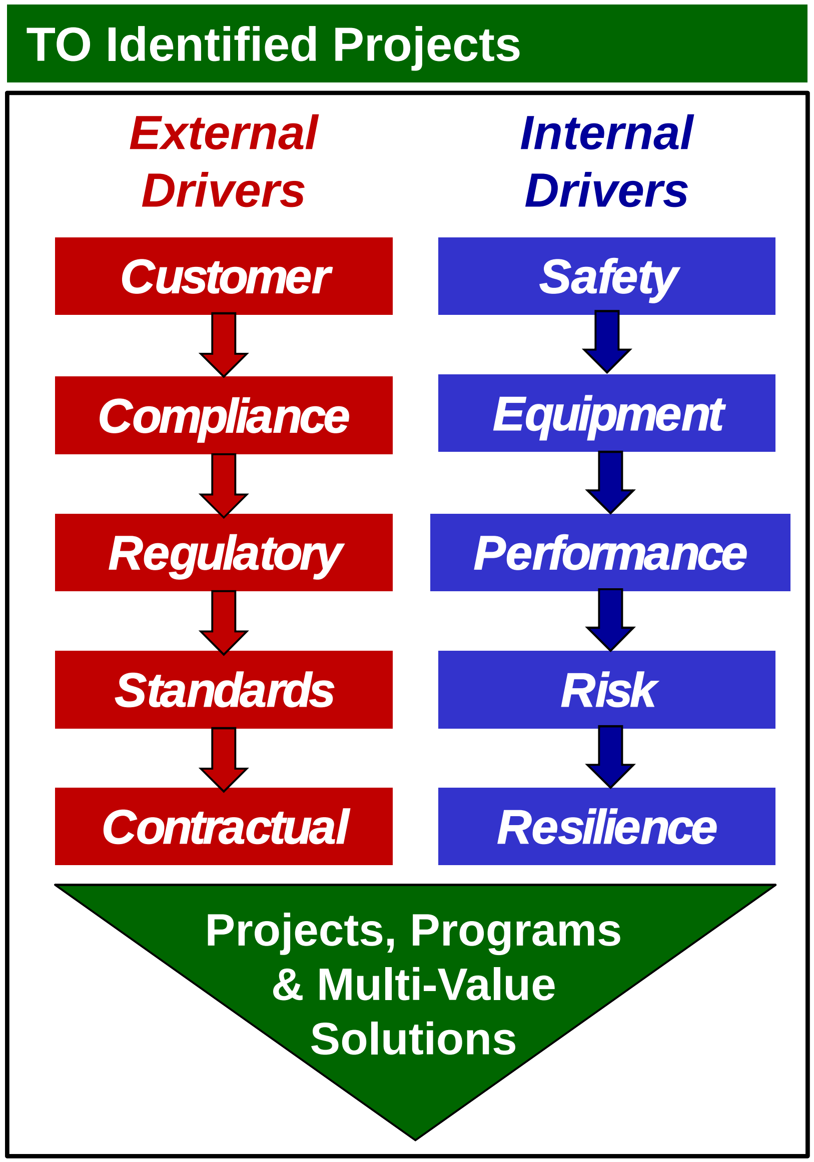
- AEP may, at its discretion, develop plans to serve projected (non-contracted) load levels provided by customers in consultation with local and state economic development organizations.
  - Any required upgrades to meet projected loads are considered supplemental.

Link to AEP Interconnection Requirements:
http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/Requirements/AEP_Interconnection_Requirements_Rev1.pdf

Types of Projects in PJM Region



Supplemental Project Drivers



Transmission Needs Identification

Source	Types of Input	Sample Examples
Internal	Field reports on asset conditions Asset Health Monitoring	Station and line equipment age; Equipment deterioration identified during routine inspections; Transmission line structure deterioration (rot, woodpecker damage)
	Capabilities and abnormal conditions	Relay misoperation; Voltage unbalance
	Obsolete system configurations	Ground switch protection schemes for transformers; Transmission line taps without switches; Equipment with no parts or no longer supported by vendors
	Outage duration and frequency	Outages resulting from equipment failures, misoperation, 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
	Customer feedback	Voltage sag issues to customer delivery points due to poor sectionalizing, frequent outages to facilities directly affecting customers
	State & Federal policies, standards, or guidelines	New NERC standards for dynamic disturbance recording
Both	Environmental & community impacts	Equipment oil spills & gas leaks, facilities currently installed at or near national parks, national forests, or metropolitan areas
	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

Transmission Needs Prioritization

Customers Input

- Collect Customer & Stakeholder Feedback
  - Historic & Projected Impacts
  - Customers' plans for the future

Historical Performance

- Review Reliability & Availability Metrics
  - System : TSAIFI,TSAIFI-S, TMAIFI, TSAIDI
  - Customer: SAIFI, SAIDI, CAIDI, CMI
  - Evaluate asset contributions to metrics
- Review Trends & Analyze Root Causes
  - Initiating causes; sustained v. momentary causes
  - Maintenance & remediation requirements & trends

Asset Condition

- Assess Asset Condition (Per Internal Standards)
  - # conditions requiring immediate attention
  - # conditions requiring mitigation within 18 months
  - # conditions requiring mitigation in 2-3 years

Future Risk

- Evaluate risk
  - Review anticipated customer/system/public impact

Prioritize Needs & Develop Mitigations

Mitigating Solutions

Integrate

- Develop cost effective, holistic solutions; combine needs in a given area to reduce outages, number of crews, mobilization, etc.
- Address all conditions identified, where possible, for a given asset being revitalized
- Determine and reduce environmental / outage / public impact

Scope

- Define & vet specific project scopes, schedules and estimates
- Conceptual and Functional level scopes and estimates developed to assess the viability of a given solution

Execute

- Review portfolio of needs and solutions with stakeholders
- Submit model changes to RTO for topology changes
- Detailed level scopes, estimates and schedules developed

Note: Not all TO-identified projects alter system topology: e.g., SCADA, RTU, PMU, Telecom, physical/cyber security, protection & control, monitoring, like kind asset replacement, etc.

AMERICAN ELECTRIC POWER

AEP Transmission Local Planning Assumptions

PJM Sub-regional RTEP

Western Meeting

January 30, 2018

Introduction to AEP

- **AEP is among the largest electric utilities in the United States**
  - More than 5.4 million customers
  - 200,000 + sq. mi. service territory
  - 26 GW of generating capacity
  - Over 40,000 miles of electric transmission lines
  - More than 3500 substations
  - 224,000 miles of electric distribution lines

- **Largest owner of electric transmission in the United States**
  - Own, operate, and maintain transmission facilities in 3 RTOs and 11 states
  - Interconnection with 60 major utilities across the U.S.
  - Supplying ~10% of demand in Eastern Interconnection and ~11% of demand in ERCOT

AEP Zone in PJM

- Total AEP Transmission facilities in PJM region: ~23,000 miles

765 kV	~2,200 miles
500 kV	~100 miles
345 kV	~4,000 miles
230 kV	~100 miles
161 kV	~50 miles
138 kV	~9,000 miles
Sub-T	~8,000 miles

- Connected demand modeled in AEP Transmission zone in PJM

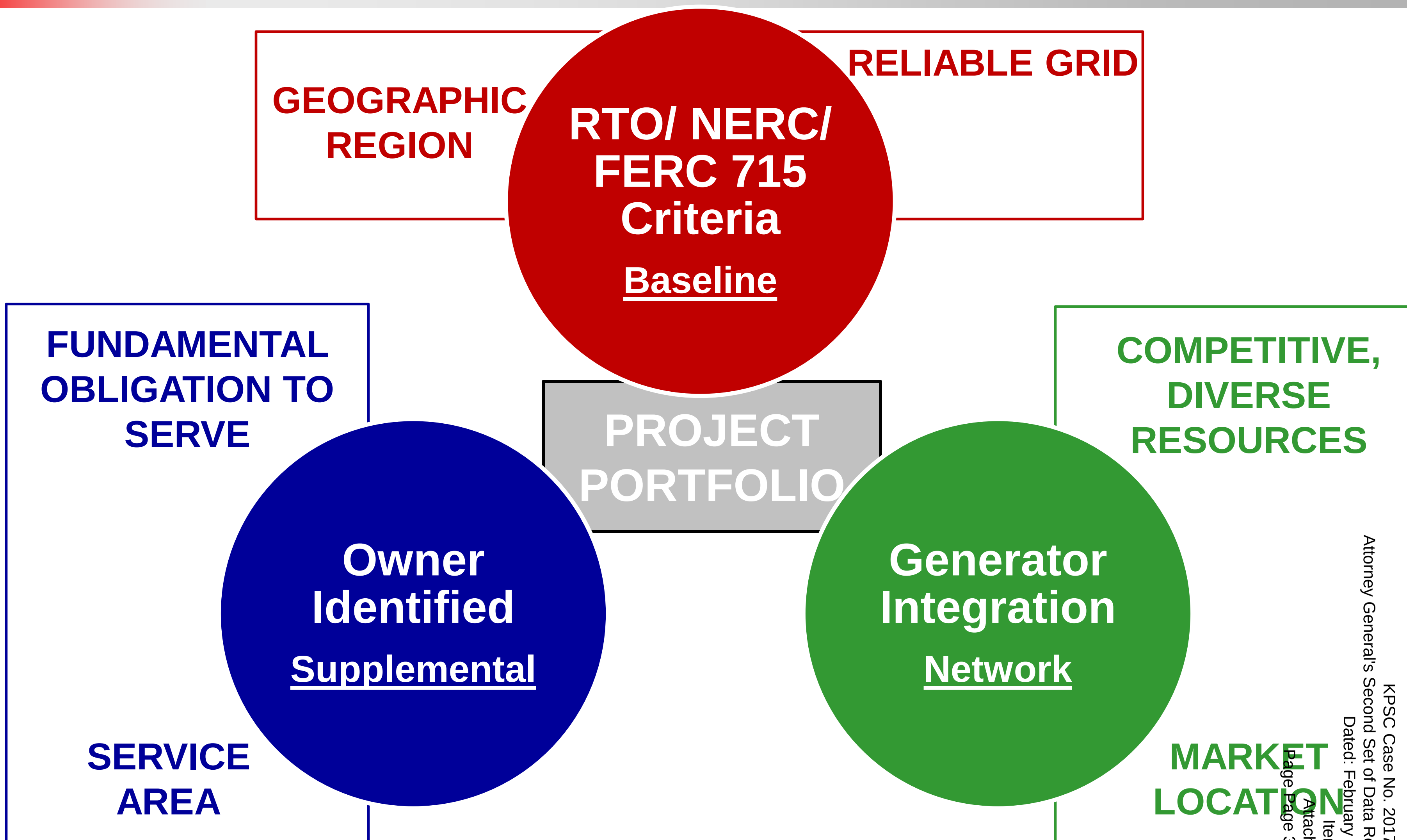
	2023 Summer	2023/24 Winter
Appalachian	6,082 MW	7,348 MW
Indiana Michigan	4,790 MW	4,032 MW
Kentucky	1,003 MW	1,279 MW
Ohio	11,033 MW	9,646 MW
Total	**22,908 MW**	**22,305 MW**

- AEP load in the RTEP case is scaled to PJM forecast.

PJM Power Flow Models

- AEP supports development of and updates to RTEP cases.
- AEP participates in development of annual series of ERAG MMWG base cases through RFC.
  - Cases include seasonal, near-term, and long-term models used in ERAG and RFC assessments of the Transmission system.
- AEP planning studies utilize available PJM RTEP cases.
  - AEP has both summer and winter peaking zones.
  - Internal cases are developed, on case by case basis, to represent and address local historic constraints observed in real-time.

Types of Projects in PJM Region



AEP Planning Criteria – FERC 715

- AEP transmission system is planned in adherence with NERC TPL-001-4 and PJM planning procedures outlined in Manual 14B.

- AEP Planning Criteria (FERC 715) complements the NERC and RTO planning procedures.
  - Includes criteria to plan non-BES system (below 100 kV).

- All planning studies utilize the latest available PJM RTEP cases.

- PJM evaluates compliance and adherence to above standards, procedures, and criteria from regional perspective (top down), and AEP does the same from a local perspective (bottom up).

Link to AEP FERC 715:
http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

Customer Interconnections

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- In accordance with NERC Standard FAC-001-2, AEP has posted requirements for interconnections of end-use customers, generators, and transmission facilities.
- To provide service to end-use customers, AEP performs initial studies to determine the system impacts and develop a plan of service for contracted load levels.
  - Required transmission upgrades are validated by PJM under baseline reliability planning criteria.
- AEP may, at its discretion, develop plans to serve projected (non-contracted) load levels provided by customers in consultation with local and state economic development organizations.
  - Any required upgrades to meet projected loads are considered supplemental.

Link to AEP Interconnection Requirements:
http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

Guidelines for TO Identified Needs

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- AEP has posted a document to outline guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency.

- The AEP guidelines allow AEP to determine which asset needs will be most impactful to overall grid performance and service to customers so that solutions can be identified within appropriate time frames.

- AEP then takes a holistic view of all the needs, developing solution options for consideration to best address the identified needs.

Link to AEP Guidelines for TO Identified Needs
http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

REQUEST

AG_2_003 Refer to the Company's Response to the Attorney General's Initial RFI Question 1.b, where it states that "[t]he focus of the Eastern Kentucky Transmission Program is the rehabilitation of existing lines and facilities and thus encompasses transmission needs that fall outside of PJM baseline criteria." Also refer to the Company's Response to the Attorney General's Initial RFI Question 1.d, where it states that "[t]he Eastern Kentucky Transmission Program is not limited to either baseline or supplemental projects."

a. Explain whether the Company's Eastern Kentucky Transmission Program is designed to focus on transmission projects which are largely Supplemental as defined by PJM.

b. Provide the criteria used to determine which "existing lines" are in need of "rehabilitation" and how the Company determines the priority of those lines.

RESPONSE

a. Please refer to the Company's response to AG 1-1(b), which provides in pertinent part:

> ***The focus of the Eastern Kentucky Transmission Program is the rehabilitation of existing lines and facilities and thus encompasses transmission needs that fall outside of PJM baseline criteria***. Kentucky Power anticipates that the majority of the projects will be designated supplemental by PJM or will involve, as is the case with the Hazard-Wooton project, both baseline and supplemental elements.

(emphasis supplied). *See also*, Testimony of Company Witness Wohnhas at 3 .

b. The "AEP Guidelines for Transmission Owner Identified Needs," attached as part of the Company's response to AG 1-1(d), provides complete information on the criteria and process used by Kentucky Power to identify transmission owner needs to address, equipment and material conditions, performance, and risk, including existing lines requiring rehabilitation, while considering infrastructure resilience, and operational flexibility.

Witness: Michael G. Lasslo

REQUEST

AG_2_004 Refer to the Company's Response to the Attorney General's Initial RFI Question 6. Explain fully the internal review and approval process which would authorize the Company to exceed the budget for this project.

a. Provide any and all documentation which details this review and approval process, and state the employee(s) and company officers of both KPCo and any of its affiliates who would make the necessary approvals. For each such individual, identify their name, job title and employer.

b. State whether AEP has a policy which KPCo and its affiliates must use to gain such approval and explain any such policy.

c. Does the Company make the Commission aware of initial budget and final costs of transmission projects when requesting cost recovery from the Commission or FERC?

RESPONSE

a-b. Capital improvement (CI) requisitions, which establish a project budget, must be approved at a Subcompany board meeting. Under the Company's Improvement Requisition Policy and Procedures (refer to KPCO_R_AG_2_4_Attachment 1), an approved CI requisition must be revised and re-approved if certain thresholds are exceeded. The thresholds include increases in the estimated total cost, including contributions in aid of construction, removal, and allowance for funds used during construction, that exceed the approved CI requisition amount by the lesser of 20% or $5 million, or when there is a significant change in the scope of the transmission line project. These thresholds do not apply, and revision and re-approval is not required, if the increase above the approved CI requisition amount is less than $100,000.

The CI and any revisions must be approved in accordance with the AEP Authorization Policy (refer to KPCO_R_AG_2_4_Attachment 2) which specifies the following authorization limits:

Authorization Limits	Officer Title	Current Officers
CIs up to $10 million	Company Presidents AEP Service Corporation SVPs	Matthew Satterwhite, President & COO, Kentucky Power Wade Smith, SVP-Grid Development, AEP Service Corporation
CIs up to $20 million	AEP Service Corporation EVPs	Lisa Barton, EVP-Transmission, AEP Service Corporation
CIs over $20 million	Chief Executive Officer	Nick Akins, CEO, AEP Service Corporation

Thus, a transmission project CI for Kentucky Power with an estimated cost of $9 million must be approved by the Subcompany board and Messrs. Wade and Satterwhite. A request to exceed the original $9 million estimated cost for the project by $2 million (for a total of $11 million) must be approved by the Subcompany board, Messrs. Wade and Satterwhite, and Ms. Barton. Ms. Barton's approval also is required because the total modified estimated cost exceeds $10 million.

c. The Company objects to this data request on the grounds that it is overly broad, unduly burdensome, and seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence to the extent it requests information about projects other than the Hazard-Wooten project, or about the determination of rates subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission. Without waiving these objections, the Company states as follows:

Kentucky Power provides all information required by law or regulation. Kentucky Power provided estimated costs for the project in its Application and supporting Testimony. Please refer to Application ¶¶ 20-21; Testimony of Ranie K. Wohnhas at 16-18.

Witness: Ranie K. Wohnhas

Title:	Improvement Requisition Policy and Procedures	**Date:**	June 23, 2016
Owner:	Oliver Sever, SVP – CP&B	**Sponsoring Area(s):**	Corporate Planning and Budgeting

Policy Purpose Statement:

This document contains requirements for processing, approving and monitoring Improvement Requisitions (IR's), including both Capital Improvement (CI) and Lease Improvement (LI) requisitions.

Detail:

1. Introduction

1.1. Dollar limits for the approval of Improvement Requisitions (IR's) must adhere to AEP's Authorization Policy.

1.2. Detail instructions for preparing, revising and closing IR's and related system information are maintained in the Improvement Requisition and Project Instruction Manual.

1.3. Both of the above documents can be found on CP&B's website. Questions regarding any of these policies and procedures can be directed to the Capital Budgeting Group email address.

2. Capital Improvement (CI) Requisitions

2.1. A CI represents a formal request for authorization of construction expenditures which will be financed by the Company's own capital.

2.2. A CI must include the entire scope of a project/program or distinct phase with all overheads and loadings. Expenditures include Capital, Removal (net of salvage) and AFUDC. For example, if a CI is submitted to procure materials in advance, the requisition must include a best estimate of the full project or phase cost, and not solely an estimate of materials.

2.3. A CI must include associated O&M as a memo item. However, associated O&M is not approved with the requisition because it is assumed to be included in or offset within the Control Budget.

3. Lease Improvement (LI) Requisitions

3.1. An LI is a formal request for the authorization of capital expenditures that will be financed through outside lease arrangements.

3.2. In most situations involving new assets the amount of capital to disclose on the LI should be the fair market value of the leased assets as of the commencement of the lease.

3.3. No leasing term less than one year should be contemplated. For periods of less than one year, rental arrangements should be made.

3.4. Lease payments for each year of the lease and other expenses associated with leases, such as property taxes, insurance, etc., are expenses and should be disclosed on the LI and included in the Control Budget. In cases where a lease has not been budgeted, all the associated expenses must be offset elsewhere in the budget or with additional revenue prior to LI approval.

4. CI / LI Types

4.1. Stand-Alone Project: Request for funds for a single function and a single legal entity.

4.2. Program: Request for funds that involve one or more legal entities (e.g., APCo and OPCo) or functions (Transmission, Distribution, Software). A single requisition should be prepared, but all applicable legal entities involved should be included in the routing and approval process.

4.3. Phased Requisition (can be used for either a Stand-Alone Project or Program): Request for project funding in phases. A phased requisition is intended to be used to obtain authorization for large projects that require a significant amount of engineering and design work to be performed before a reasonable cost estimate can be obtained. It is also recognized that for these types of projects, some commitments may be required where long lead time equipment is needed in order to meet critical operational dates. In order to permit those necessary activities, it is permissible to prepare and submit an IR in phases.

Under normal circumstances the following numeric phases are allowed:

- Phase 1 – Requests authorization for funds to perform preliminary engineering and design work required to arrive at an initial estimate.
- Phase 2 – Requests authorization for funds to procure long lead time equipment and materials, perform preliminary site work.
- Phase 3 – Requests funds for the final project scope, commitments and expenditures required to complete the project.

Additionally, the following applies to phased improvement requisitions:

- In addition to the funding authorization request for each phase, the total estimated cost for all phases must be disclosed on the IR for each phase.
- For each phase identify the current numeric phase and the total number of phases in the Phase Description section (e.g. Phase 1 of 3) along with an explanation of the deliverable for the current phase.
- For subsequent phases after the first phase, the original total estimated cost for all phases must be retained and disclosed on the IR in the original Scope/Description section.
- Each phase of a requisition will be monitored separately and if costs exceed revision thresholds, the requisition must be revised for that phase. (*Refer to Section 8 for related Revision controls*)

4.4. Blanket/Annual Program: Request for a lump sum dollar amount (based on a calendar year) for work that is repetitive, predictable in nature or for a specific scope of work. Each job within a blanket has a total dollar limitation that cannot be exceeded. Blankets/Annual Programs are authorized annually and must be reauthorized each year. Refer to Section 12: Appendix A for the approved listing and dollar limitations of Blankets/Annual Programs.

- Generation, Transmission and Distribution Blankets/Annual Programs – one requisition should be submitted for each Region/Company and function
- Corporate Group Blankets – one requisition should be submitted for each type of blanket with all companies included

5. Process Overview

5.1. Shown in Exhibit A are the high-level steps that are to be followed in preparing, routing and approving a CI or LI Requisition and the associated responsible party for completing each activity.

Exhibit A: Process Steps and Responsibility

	Step *Note: Steps 4 and 6 are not applicable for non-utility operating companies*	**Responsibility**
1	Prepare IR/Exec Summary in PeopleSoft Projects, Identify Budget Offsets if needed, Route for Approval	BU Originator and BU Budget Group
2	PAR Review of IR - Review Content & Verify Funding *(Refer to Section 13.1 for related Sarbanes-Oxley controls)*	Planning, Analysis & Reporting (PAR) Analyst
3	Obtain Regulatory Language	Central Regulatory Services
4	Review Requisition (including Regulatory Language and Funding)	Opco VP Regulatory & Finance
5	Approve IR by BU	BU Sr. VP or Designee
6	Approve IR by Opco	Opco President or Designee
7	Perform Final Review Tasks and Route to EVP/COO/CEO (as needed) *(Refer to Sections 13.1 and 13.2 for related Sarbanes-Oxley controls)*	PAR Manager
8	Approve IR by EVP/COO/CEO, as needed	EVP/COO/CEO
9	Perform Subco Board Report Tasks	PAR Analyst
10	Subcompany Board Meeting	

6. Funding

6.1. The sponsoring Business Unit is responsible for insuring that funding exists for all years. If funding is not sufficient, the sponsoring Business Unit must identify offsets and attach a fund transfer in the routing database.

6.2. The operating company Regulatory & Finance organization must verify that funding exists or that funding has been identified with a fund transfer *prior* to routing the IR for subsequent approvals.

6.3. If funding is not available, the VP, Regulatory & Finance or designee should coordinate with the sponsoring Business Unit (BU) to identify offsets either within or outside of the operating company.

7. Routing and Approval

7.1. The authorization level for approval of an initial requisition is based on the Total Amount to be Authorized.

7.2. An IR may be sent to the CEO or an EVP for approval (regardless of dollar amount) at CP&B's discretion, based on the uniqueness or strategic importance of the request.

7.3. The final approvers of any IR must have sufficient approval authority. Approval Authority Limits are maintained in the HR Financial Approvals system under the transaction type "CI / LI".

7.4. Approvals are required both by AEP management in accordance with the AEP Authorization Policy and by the Subsidiary Company Board of Directors at one of its monthly meetings. Expenditures and commitments can be made against an IR after AEP Authorization Policy compliant approval is obtained. Subsidiary Company Board of Directors approval is still required at a subsequent meeting.

7.5. If the IR is > $3M for T, D and G and > $2M for other functions, a one page summary of information is required to be included as part of the Subsidiary Company Board of Directors document.

7.6. IR's originated by support services groups for the specific benefit of one or several business groups will be signed by appropriate individuals within the originating support services group and then approved by the recipient group(s). However, support services groups can approve capital dedicated to corporate stewardship per their limits.

7.7. LI requisitions must be reviewed / approved by Corporate Finance and must conform to their Leasing Policy.

8. Revisions

8.1. An IR should be revised if the projected cost (estimated total cost, including CIAC, Removal and AFUDC) is expected to be overspent by 20% or $5 million, or when it is known that there will be a significant change in scope, location, or generating unit. If the total authorized amount for an IR (including CIAC, Removal and AFUDC) is overspent by less than $100,000, a revision is not required. This minimum overspend threshold of less than $100,000 does not apply to Blankets, Annual Programs, or CIs/LIs with authorized spend of less than $500,000. *(Refer to Section 13.3 for related Sarbanes-Oxley control.)*

8.2. All IR's, including annual programs and blankets, require a revision be approved prior to exceeding the applicable revision threshold. *(Refer to Section 13.5 for related corporate governance monitoring.)*

8.3. The revision should include an explanation of why costs exceeded the approved estimate. In preparing the revision, clearly specify the previously authorized total estimated cost, the revised incremental cost being submitted for approval and the revised total estimated cost.

8.4. For Phased IR's, each phase is subject to the revision procedure.

9. Closing

9.1. IR's and associated work orders should be closed in a timely manner upon project completion. For work order policies, refer to the Accounting Website under Property Accounting. *(Refer to Section 13.6 for related corporate governance monitoring.)*

10. Controls and Monitoring

10.1. The Sarbanes-Oxley (SOX) Act of 2002 requires AEP and our other SEC registrants to perform a quarterly review and update the documentation of significant internal controls.

10.2. Refer to Section 13, Appendix B: Sarbanes-Oxley Controls and Corporate Governance for a list of primary and secondary SOX control activities as well as additional governance activities related to monitoring IR's.

11. Special Considerations

11.1. Capitalized Software

- For capitalized software that is less than $10 million, an IR in the name of AEPSC will be established.

Costs will be billed to the benefitting GLBU's monthly.

- For software projects greater than $10 million, with the exception of Corporate Stewardship projects, individual projects will be established under a Program Requisition for each GLBU receiving a direct allocation of the total. If a software project greater than $10 million consists of several distinct software products where no one product exceeds $10 million, the establishment of individual projects can be waived.

11.2. Cardinal Operating Company

- All capital improvements exceeding $50,000 must also be approved by Buckeye.

11.3. Equipment or Facility Transfers

- When the cost of a capital project includes materials and/or equipment purchased from an associated company, the purchasing company may need to prepare an improvement requisition if the Total Amount to be Authorized for the project exceeds the blanket authorization limit. However, the transfer value of the materials and/or equipment should not be included when calculating the Total Amount to be Authorized. Overheads and AFUDC should not be applied to the material cost of the purchasing company, since such costs were included in the initial material cost.
- For additional information, see AEP System Accounting Bulletin No. 21, Sales of Material and Equipment Between Associated Companies. For a copy of the Accounting Bulletin, refer to the Accounting Website.

11.4. Jointly Owned Facilities

- For investments by AEP companies in jointly owned facilities which are not owned by a joint venture entity, the IR should be prepared for the amount of cost AEP is obligated to incur.
- If partners have not yet made binding commitments to the project, that fact should be disclosed and the IR should be prepared for 100% of the cost of the project. When partners make binding commitments to the project, the IR should be revised to reflect AEP's share of the cost.

11.5. Joint Ventures

- The process for requesting approval for capital projects for JV's is governed by the definitive JV agreements or by Authorization Policies adopted by the JV's.
- For JV's such as Electric Transmission Texas (ETT), Potomac Appalachian Transmission Highline (PATH), and future similar JV's for which AEP keeps the books and records and is the project manager, IR's should be prepared for 100% of the project cost. They are reviewed and approved by the JV governing body which includes appropriate AEP management. Requisitions greater than $3M are included in the monthly AEP Subsidiary Companies Board package as "Information Only".
- Each partner's share of the total cost and the anticipated financing structure should be disclosed in the IR. In the event either partner or the JV itself has not made a binding commitment to the project at the time the IR is prepared, that fact should be disclosed in the IR.

11.6. Preliminary Engineering and Survey Work

- Projects that require preliminary survey and investigation work for the purpose of obtaining scope and cost estimates needed for an improvement requisition, will utilize the pre-engineering project process in PeopleSoft Projects (see Improvement Requisition and Project Instruction Manual on CP&B's website).
- Generation / Nuclear business units will continue to use their existing pre-engineering & survey work processes (see Capital GSWO business rules).
- Expenditures for this work should only include company labor (including fleet allocation), contract labor and employee expenses. No right of way, land acquisition, construction labor or material commitments should be made prior to IR approval. If it is determined that the project will not be routed as an Improvement Requisition business units would need to adjust project scope or address appropriate treatment with Accounting.
- Pre-engineering spend is limited to $500K per project and should be monitored by individual business units to ensure this amount is not exceeded.
- All pre-engineering spend will be monitored as part of company functional blanket spend (I&M Transmission blanket, Kentucky Distribution blanket, etc.) regardless of the year pre-engineering spend occurs and subject to revision requirements in section 10 of this policy.

- Projects are considered “pre-engineering” under the following conditions: Project Status 2 (opened), CI Version 1 (initial version and not a revision), CI Status not A (where A indicates a requisition is approved).
- Pre-engineering projects will be monitored within blankets that correspond to the organization performing pre-engineering. As an example, distribution function pre-engineering projects being performed within the Transmission organization will be monitored as part of Transmission blanket spend.

11.7. Other Considerations

- AEP Authorization Policy compliant exceptions to this policy require approval from the owner of this policy.

12. Appendix A: Approved List of Blankets and Annual Programs

	Capital / Lease	Total $ Limitation of each Job
Generation Blankets		
Production Plant	Capital	< $500,000
Nuclear Minor Improvement	Capital	< $500,000
Marine Plant	Capital / Lease	< $500,000
Mine Plant	Capital / Lease	< $500,000
Railcar, Barge, Towboat, Real Estate	Lease	= delegated SVP limits
Transmission Blankets		
Customer Service	Capital	< $500,000
Public Projects Relocation	Capital	< $500,000
System Improvement	Capital	< $500,000
Asset Improvement Transmission-driven Distribution	Capital	< $500,000
Distribution Blankets		
Asset Improvement Distribution-driven Transmission	Capital	< $500,000
Customer Meter	Capital	< $500,000
Customer Service	Capital	< $500,000
Line Transformer	Capital	< $500,000
Public Projects Relocation	Capital	< $500,000
Reliability Improvement	Capital	< $500,000
Service Restoration	Capital	< $3,000,000
Small Capacity Additions	Capital	< $500,000
3rd Party Work Request	Capital	< $500,000
Distribution Annual Programs		
Forestry / Right of Way Widening	Capital	< $500,000
Cutout and Arrester	Capital	< $500,000
Line Recloser	Capital	< $500,000
Small Wire Overhead / Underground	Capital	< $500,000
Pole Replacement	Capital	< $500,000
Sectionalizing	Capital	< $500,000
PSO Overhead to Underground Conversion	Capital	< $500,000
PSO System Hardening	Capital	< $500,000
PSO Worst Performing Circuits	Capital	< $500,000
Corporate Blankets		
General Plant	Capital / Lease	Facility lease renewals no limit, all other < $500,000
Telecommunications	Capital / Lease	< $500,000
Capitalized Software	Capital	< $500,000
Computer Equipment	Lease	< $500,000
Mobile Radio	Lease	Limit of $5,000 per item
Automotive / Transportation (Roll Over / Replacement)	Lease	No limit on a per unit basis
Mobile Material Handling	Capital/Lease	No limit on a per unit basis

13. Appendix B: Sarbanes-Oxley Controls and Corporate/Business Unit (BU) Governance

SOX Controls Corporate Governance		Procedure	Corrective Action	Responsible *Frequency*
SOX Controls				
13.1	**Classification of Work** Scope of work submitted for approval is Capital *(Primary Control)*	Verify that work described on IR's is capital work in accordance with Accounting Bulletins	IR's identified as non capital are omitted from the IR Process	PAR *Monthly*
13.2	**Approval Authorization** Capital work is properly authorized per the AEP Authorization Policy *(Primary Control)*	Verify that IR's are approved by the appropriate level of management before authorizing in PeopleSoft and subsequently by the Sub Co Board of Directors	IR's that are not approved by the appropriate level of management are not authorized in PeopleSoft or submitted to the Sub Co Board of Directors until appropriate approvals are obtained	PAR *Monthly*
13.3	**Overspent IR's** Spending Authorization for approved IR's is not exceeded *(Primary & Secondary Control)*	Review IR actual costs as compared to the approved estimate to determine if projected costs are going to exceed approved estimate	Revisions are prepared when it is projected that costs will exceed corporate revision tolerances	BU's / PAR *Quarterly*
Corporate/BU Governance Monitoring				
13.4	**Spending Limit** Annual Budget approved by the Board will not be exceeded by more than $50M without approval from the AEP Inc. Board of Directors	Monitor the Budget (Spending Limit) that is approved annually by the AEP Inc. Board of Directors	Obtain approval from the AEP Inc. Board of Directors in the form of a Board resolution prior to exceeding the limit If the amount overspent cannot be determined until after the year end books are closed, then obtain approval at the next scheduled Board meeting after the books are closed	PAR *Monthly*
13.5(a)	**Blankets / Annual Programs** **(Aggregate Spend)** Spending for approved Blankets /Annual Programs is not exceeded (including pre-engineering spend)	Monitor percent of aggregate actual spend to budget to ensure blankets / annual programs are revised prior to overspending **total by function and region/company*	Revisions are prepared when it is projected that costs will exceed corporate revision tolerances	PAR / BU's *Monthly, beginning in July*
13.5(b)	**Blankets / Annual Programs** **(Individual Jobs)** Spending for individual jobs within a Blanket / Annual Program is not exceeded	Monitor individual jobs within a blanket / annual program to determine if projected costs are going to exceed approved total dollar limitation and submit monitoring report results to PAR	Provide PAR with planned resolution when it is projected that an individual job costs will exceed corporate revision tolerances (see Appendix A)	BU's / PAR *Quarterly, beginning in April*
13.6	**In Service Dates** IR's that have an in service date 12 months prior to the current date are reviewed	Identify stale IR's that have an in service date 12 months prior to the current date and have NOT been closed	Schedule of identified IR's is prepared and the appropriate parties are contacted, requesting that the IR be closed or that the in-service date is updated	PAR / BU's *Quarterly*
13.7	**Project Approval**	Verify capital/removal projects > $500K ($3M for service restoration) have an approved IR	Prepare and route an IR for Sub Company Board approval	BU's *Monthly*

Review / Revision:

Every policy must be reviewed and certified as current on an annual or more frequent basis. The most current of those dates and the employee conducting it should be shown here, with that date added to the top of the first page and the footer of all pages. At the discretion of the owner, more detailed "Edit History" and/or "Approvals" areas may be maintained here, showing all activity on this policy over the specified time period.

Approved by: Oliver Sever – 06/23/2016

Title:	AEP Authorization Policy (REV 001)	**Date:**	May 29, 2015
Owner:	Brian Tierney, Chief Financial Officer	**Sponsoring Area(s):**	CP&B and Corporate Accounting

Policy Purpose Statement:

This Policy provides guidance necessary to ensure all commitments and financial transactions on behalf of the Company are properly authorized, and that such authorization is appropriately documented.

Detail:

1.0 **Scope:** This policy provides the corporate rules governing the assignment of authority to authorize commitments and financial transactions. Such authorization authority shall be considered a core management responsibility and shall be delegated only to the extent necessary.

1.1 The Board of Directors of the Parent Company, by resolution dated April 23, 2013, authorized and adopted the following:

- that the Chief Financial Officer of American Electric Power Service Corporation be, and hereby is, authorized and directed to issue and administer a Corporate Authorization Policy providing dollar limits for the approval of transactions within the guidelines summarized in Exhibit A (see page 3) and establishing procedures for the delegation of authority by the executive officers of the Company and American Electric Power Service Corporation within their respective limits; and further
- that the Chief Financial Officer of American Electric Power Service Corporation be, and hereby is, authorized to revise the Corporate Authorization Policy, as necessary from time to time, subject to the guidelines summarized in Exhibit A.

2.0 **Policy Details:**

2.1 General Principles:

2.1.1 This Authorization policy governs the approval of transactions related to the following:

- Acquisitions and Divestures
- Capital and Lease Improvements
- Commitments (contracts, purchase requisitions, lease agreements, releases, letters of intent, hiring employees and other agreements/expenditures that commit funds of the Company)
- Guarantees

2.1.2 Related policies not included in this document must be followed in concert with this policy:

- Acquisitions and Divestures – ***AEP Strategic Decision Guidelines*** administered by Risk and Strategic Initiatives
- Capital and Lease Improvements – ***AEP Improvement Requisition Policy and Procedures*** administered by Corporate Planning & Budgeting
- Commitments for the Acquisition of Goods and Services - ***AEP Procurement Policy*** administered by Supply Chain, Procurement and Fleet
- Credit card transactions - ***AEP Credit Card Policy*** administered by Supply Chain, Procurement and Fleet
- Guarantees - **AEP *Corporate Financing Policy*** administered by Treasury.

2.1.3 This Policy shall not contradict the operation of law nor supersede authorizations in approved board resolutions, including the following: banking transactions, borrowing transactions, energy trading transactions and tax payments.

2.2 Authorization Limits and Delegation of Authority Procedures:

2.2.1 Authorizations shall be approved as final only by AEP or subsidiary company authorized officers or employee delegates within the authorization limits established in Exhibit A (see page 3). **Contractors shall not have final approval authority**.

2.2.2 Officers listed in Exhibit A may delegate up to their authority either permanently or temporarily. **Delegation of authorization authority exceeding $10,000 shall only be made to employees at or above salary grade 9 in the new SP20 salary structure, effective January 2, 2015, or at or above salary grade 24 in the EXEM structure.** Delegations in excess of $10,000 to employees below this level require approval review by the Chief Procurement Officer (CPO) as delegated by the Chief Financial Officer (CFO) and will only be permitted when supported by evidence that such delegation is necessary due to unique circumstances.

2.2.3 Delegation of authority shall generally be assigned electronically in the Human Resources (HR) Financial Approvals System. Authorization Exception Requests, created as a result of 2.2.2 above, will be routed for approval within the system as such: 1st level approval to the next member of the organizational hierarchy grade 9/24 or above; 2nd level approval to the system administrator (Accounting Operations); 3rd level approval to the CPO.

2.2.4 Delegation of authority control is defined in the ***Financial Approvals Procedures*** maintained by Accounting.

2.2.5 All delegations of authority within the Financial Approvals System automatically result in a system-generated email notification to the manager one level above the delegator.

2.2.6 In certain instances it may be necessary to provide specific individuals with high authorization limits to cover particular items such as dividend payments, taxes, fuel, etc. Additionally, business units or groups may want to process many changes at once due to organizational changes (new roles, new reporting relationships, etc.). In these cases, the delegator may not want to include everyone in the delegation chain or process every change individually. It is acceptable for the delegator(s) to provide written approval to the system administrator to make such delegation, and the system administrator will retain the documented approval.

2.2.7 It is the responsibility of each individual who is delegated authorization limits to act in the best interest of the Company in exercising such authority. Delegation of authority to subordinates should only be done when necessary for efficient and effective performance of the subordinate's responsibilities. **In all cases in which an individual delegates a portion of their approval authority to a subordinate the delegator retains responsibility for assuring the appropriateness of the subordinate's use of that authority.**

2.2.8 Delegations shall be restricted both in terms of number of individuals receiving delegations and the limits delegated, to the extent possible. **Annually each individual who has delegated authorization limits to subordinates shall reassess the need to continue such delegation, and at what level, based upon each of the delegate's job responsibilities.** If a delegate has not exercised their authorization authority over the past year, or has not authorized transactions at a level as high as their current authorized level, it is a strong indicator that such delegation is probably not required or not required at the current level. The completion of this review and results are to be reported annually to each delegator's manager. **Compliance with this requirement is subject to periodic audit.**

As approved by the Board of Directors of American Electric Power Company, Inc. on April 23, 2013

Exhibit A: Authorization Limits Table (excluding internal AEP transactions)

Item	AEP Inc. Board of Directors	Chief Executive Officer	AEPSC EVPs	Company Presidents, AEPSC SVPs
Capital and Lease Improvement Requisitions				
If within the latest approved total annual spending limit*		Over $20 Million	Up to $20 million (and all blankets/annual programs)	Up to $10 million (except as delegated)
If in excess of total annual spending limit*	Over $50 million	Up to $50 million	No authority (except as delegated)	No authority (except as delegated)
Acquisitions**	Over $50 million	Up to $50 million	No authority (except as delegated)	No authority (except as delegated)
Divestitures**	Over $50 million	Up to $50 million	No authority (except as delegated)	No authority (except as delegated)
Other				
Other Commitments***		Over $20 million	Up to $20 million	Up to $10 million (except as delegated)
Guarantees	The CFO or Treasurer (except as delegated) must approve all guarantees.			

*Total annual spending limit
Refers to the current year spend submitted to and approved by the AEP, Inc. Board of Directors each year (Approved Budget). This limit applies only to the current year; however, all future dollars for multi-year projects are required to be included in the latest forecast.

**Acquisitions & Divestitures means the acquisition or divestiture of a business or substantially all the assets of a company, or any agreement for the purchase and sale of real or personal property in excess of $20 million.

***Other Commitments include contracts (e.g., fuel purchase agreements), purchase requisitions, lease agreements, releases, letters of intent, hiring of employees (including employment agreements) and other agreements or expenditures that commit funds of the Company.
O&M associated with other commitments is assumed to be included in or offset within the Approved Budget at the time the commitment is entered.

Review / Revision:

Reviewed by:	Jack Kincaid, Manager – Accounts Payable	05/04/15
Reviewed by:	Julie Williams, Assistant Controller – Accounting Operations	05/06/15
Approved by:	Brian Tierney, Chief Financial Officer	05/29/15

REQUEST

AG_2_005 Refer to the Company's Response to the Attorney General's Initial RFI Question 1.c. State whether the proposed project, and/or any of the additional projects the Company identified, contain or will contain a cap on project revenue requirements, either in whole or in part. If so, provide documentation and an explanation describing same.

RESPONSE

The proposed project is subject to the budgeting and expenditure processes and controls described in the Company's responses to AG 1-6 and AG 2-4.

Witness: Ranie K. Wohnhas

KENTUCKY POWER
CASE NO. 2017-00328
ATTORNEY GENERAL'S SUPPLEMENTAL SET OF DATA REQUESTS
DATED: FEBRUARY 2, 2018

REQUEST

AG_2_006 Refer to the Company's Response to the Attorney General's Initial RFI Question 1.c. State whether any of the Company's planned transmission projects are classified as NERC Critical Infrastructure Projects (also known as "CIP 14").

RESPONSE

The planned projects identified in response to the AG RFI Question 1c are not related to any assets identified in NERC CIP-14 analyses performed to date.

Witness: Ranie Wohnhas

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director, Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

Commonwealth of Kentucky)
)   Case No. 2017-00328
County of Boyd   )

Subscribed and sworn before me, a Notary Public, by Ranie K. Wohnhas this 9 day of February, 2018.

Trisha M. Young Blum

Notary Public

My Commission Expires 3-18-19

COMMONWEALTH OF KENTUCKY

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

VERIFICATION

The undersigned, Michael G. Lasslo, being duly sworn, deposes and says he is the Reliability Manager for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Michael G. Lasslo

Michael G. Lasslo

Commonwealth of Kentucky	)	
	)	Case No. 2017-00328
County of Perry	)	

Subscribed and sworn before me, a Notary Public, by Michael G. Lasslo this 9TH day of February, 2018.

Notary Public

My Commission Expires 4/5/2019

RONALD L. CANFIELD
Notary Public - State at Large
KENTUCKY - Notary ID # 530778
My Commission Expires April 5, 2019