UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

The Office of the Ohio Consumers' Counsel, Complainant, v. PJM Interconnection, L.L.C., American Electric Power Service Corporation, on behalf of Ohio Power Company and AEP Ohio Transmission Company, American Transmission systems, Inc., AES Ohio, a/k/a The Dayton Power and Light Company, and Duke Energy Ohio, LLC, Respondents.	))))))))))))	Docket No. EL23-105-000

COMMENTS IN SUPPORT OF COMPLAINT

Pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") September 29, 2023, Combined Notice of Filings #1[1] and the Commission's October 11, 2023, Notice of Extension of Time,[2] the PJM Industrial Customer Coalition ("PJMICC")[3], the Industrial Energy Consumers of America ("IECA"), and the American Forest and Paper Association ("AF&PA") (collectively, "Industrial Customers") hereby submit these comments in support of the Office of the Ohio Consumers' Counsel's ("OCC") Complaint against PJM Interconnection, LLC ("PJM") and the Ohio Transmission Utilities[4] relative to transmission projects in Ohio, and

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[1] Combined Notice of Filings #1, *The Office of the Ohio Consumers' Counsel v. PJM Interconnection, L.L.C.*, Docket No. EL23-105-000 (Sept. 29, 2023).

[2] Notice of Extension of Time, *The Office of the Ohio Consumers' Counsel v. PJM Interconnection, L.L.C.*, Docket No. EL23-105-000 (Oct. 11, 2023).

[3] PJMICC, IECA, and AF&PA earlier filed doc-less motions to intervene in this proceeding.

[4] The Ohio Transmission Utilities include affiliates of American Electric Power Corporation ("AEP"), being Ohio Power Company ("AEP Ohio Power") and AEP Ohio Transmission Company, Inc. ("AEP Ohio Transmission"); the FirstEnergy affiliate American Transmission Systems, Inc. ("ATSI"); AES Ohio, a/k/a The Dayton Power and Light

the transmission rates and planning processes contained in PJM's ("PJM") Open Access Transmission Tariff ("Tariff"). OCC's Complaint was filed September 28, 2023, in the above-referenced docket.[5] The Commission should grant the Complaint and require PJM to modify its Tariff to adopt the remedies discussed in these Comments.

I. BACKGROUND

The Complaint alleges that there is no oversight for "need, prudence, and cost-effectiveness" for local transmission facilities by any regulatory agencies.[6] The Complaint argues that over "85% of the estimated costs for proposed new transmission between 2018 and 2022 in Ohio are a function of utilities' spending on Supplemental Projects."[7] And because these capital investments are rolled into rate base, the Complaint alleges that the resulting transmission rates to be unjust, unreasonable, and unduly discriminatory. The Complaint advocates for amendments to the PJM Tariff, instituting an Independent Transmission Monitor, the use of stated-rate approaches for transmission rates, and the development of a different remedy should FERC reject its other proposals.[8]

Company ("AES Ohio" or "DP&L"); and Duke Energy Ohio, LLC ("Duke") (collectively, "Ohio Transmission Utilities").

[5] *See The Office of the Ohio Consumers' Counsel v. PJM Interconnection, L.L.C.*, Complaint of the Office of the Ohio Consumers' Counsel to Protect Ohio Consumers Under the PJM Tariff From the Failures of Multiple Agencies to Regulate Hundreds of Millions of Dollars in Monopoly Electric Transmission Charges for "Supplemental Projects" Planned by AEP, AES, Duke, and FirstEnergy and Request for Fast-Track Processing, Docket No. EL23-105-000 (filed Sept. 28, 2023) ("Complaint").

[6] *See id*. at p. 1.

[7] *Id*. at 25.

[8] *Id*. at pp. 33-37.

II. SUMMARY

The existing practice of allowing Supplemental Projects[9] to be built and then rolled into rate base without any meaningful regulatory oversight is unjust, unreasonable, unduly burdensome, and preferential. No practical review exists of Supplemental Projects. Prudence challenges are not viable and very rarely succeed. The Formula Rate Transmission Protocols of the Ohio Transmission Utilities suffer from serious inadequacies that cause them to fail to protect consumers and deny consumers due process. The PJM Attachment-M3 process, which the Commission adopted several years ago as a hopeful mechanism for reviewing Supplemental Projects for need and cost-effectiveness, is seriously deficient and deprives consumers of any meaningful review and engagement that would enable consumers to fairly scrutinize Supplemental Projects. State commission review during Certificate of Convenience and Public Necessity ("CPCN") application processes are insufficient in Ohio, and generally insufficient in a number of other states in the PJM Region, to enable a thorough review of Supplemental Projects for both need and cost-effectiveness. So where is the check on the level of Supplemental Project spending? There is none. And exponentially increasing transmission rates are the inevitable consequence. And that is the problem that renders the status quo unjust and unreasonable.

In the Complaint, after demonstrating that the existing regulatory structure was not just and reasonable (at least in Ohio), the OCC proposes several remedial measures, including amending the PJM Tariff; developing an Independent Transmission Monitor; using a stated-rate approach for transmission projects; and having FERC develop its own solution to ensure just and reasonable

[9] Supplemental Projects are "[t]ransmission Facilities as defined in Consolidated Transmission Owners Agreement, section 1.27 constructed by a Transmission Owner pursuant to a Public Policy Requirement but not included in a Regional Transmission Expansion Plan as a Required Transmission Enhancement." PJM Open Access Transmission Tariff, Schedule 12.b.xii.a (available at: https://www.pjm.com/directory/merged-tariffs/oatt.pdf)(last visited Nov. 10, 2023).

rates should FERC reject the other proposed solutions. While several of these options have merit, none provide the full scope of relief that the Industrial Customers' Recommendation would provide. Thus, in addition to supplementing the evidence in the Complaint, to show that existing practices are not just and reasonable, the Industrial Customers recommend that the Commission adopt a bright-line 100 kV threshold for inclusion of transmission projects into regional planning processes to ensure that consumers receive the full benefits of transmission development at the lowest reasonable cost. A voltage threshold of 100 kV would provide a bright-line, non-subjective criterion for determining transmission projects that must be regionally planned. That voltage threshold comports with prior Commission orders that recognize transmission facilities with regional and bulk electric system impacts. Regional planning would ensure independent oversight and review of proposed transmission projects, independent approval of proposed transmission projects, and synchronization with least-cost transmission planning across the entire region. Adopting a 100 kV threshold for regional planning would also expand competition to a wider array of transmission projects and would ensure a process that is purposely designed to produce transmission rates that are just and reasonable.

III. EXISTING PRACTICES ARE NOT JUST AND REASONABLE.

Using Supplemental Projects to effectuate transmission grid expansion is a practice that affects rates under the Federal Power Act. When a Transmission Owner builds a new transmission facility as a Supplemental Project, the entity will roll the capital cost of the project into rate base. This practice enables the utility to earn a return on its capital investment, and it encourages utilities to spend more than a societally optimal amount on transmission improvements. Because this practice impacts rates, the Commission has a statutory duty to provide oversight and regulation of these projects to ensure that transmission rates remain just and reasonable under Sections 205 and

206 of the Federal Power Act.[10] The practice of rolling through transmission formula rates the capital costs of Supplemental Projects that receive no meaningful review is unjust and unreasonable, and it causes transmission rates to be unjust and unreasonable.

A. Prudence Challenges Are Not a Viable Option for Containing Supplemental Project Spending.

Prudence challenges are not a viable option for consumers to contest the level of transmission owners' spend on Supplemental Projects. In fact, there appear to be no cases at least in the past 20 years in which FERC has rejected transmission expenditures as imprudent. That observation is not surprising. The presumption of prudence provided to transmission owners is highly deferential and must be overcome by concrete evidence presented by consumers, who are operating from an information deficit, before the transmission owner bears the burden of affirmatively demonstrating the prudence of its transmission investment. The process almost guarantees that consumers will fail.

The problem with the traditional prudence standard is highly deferential to the transmission owners. The standard is as follows:

> [M]anagers of a utility have broad discretion to conduct business affairs and to incur costs necessary to provide service to utility customers. The Commission held that the appropriate test to be used in a prudence review is whether the costs incurred are the costs which a reasonable utility management would have made, in good faith, under the same circumstances, and at the relevant point in time.[11]

The Commission adds,

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[10] *See California Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 400 (D.C. Cir. 2004) ("Congress empowered the Commission not merely to effect a reformation of some 'practice' in a more traditional sense of actions habitually being taken by a utility in connection with a rate found to be unjust or unreasonable . . . ."); *see also S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("a failure to act qualifies as a "practice" under Section 206 that it must remedy when the failure to act is 'unjust, unreasonable, unduly discriminatory or preferential,' 16 U.S.C. § 824e(a), and directly affects or is closely related to jurisdictional rates . . . .").

[11] *New England Power Co.*, 42 FERC ¶ 61,016 (1988), *citing Re New England Power Co.*, 31 FERC ¶ 61,047 (1985).

> A prudence inquiry addresses whether the [utility] conducted reasonable evaluation of the costs and benefits prior to incurring a financial commitment. A prudence determination is based upon what the [utility] knew or should have known at the time a decision was made. The prudence standard ensures that ratepayers are not required to pay for 'unnecessary costs.'[12]

And further,

> The regulated entity has the burden of proof to establish prudence . . . in order to ensure that rate cases are manageable, a presumption of prudence applies until the challenging party 'creates a serious doubt as to the prudence of an expenditure . . . . ' Serious doubt must be more than a 'bare allegation of imprudence,' but this threshold may not be so demanding that it effectively reverses the statutory burden of proof. Once such serious doubt has been raised, the [utility] has 'the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.'[13]

In addition, prudence determinations are highly fact-determinative, and require the complainant "to do more than make mere unsubstantiated allegations."[14] Because a serious doubt is the burden of proof, complainants have often failed to meet the burden, and they lose their cases.

The Commission has ordered evidentiary hearings to explore the prudence of certain investments, for both electric transmission and electric generation.[15] However, the only case we could find where FERC found that the complainants met the burden of serious doubt was where the utility owned a minority interest of a coal plant and a nuclear plant and failed to sue the majority

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[12] *Louisiana Pub. Serv. Comm'n, Arkansas Pub. Serv. Comm'n, & Council of the City of New Orleans, Louisiana Sys. Energy Res., Inc., Entergy Servs., LLC, Entergy Operations, Inc., & Entergy Corp.*, 181 FERC ¶ 61,135 (2022), internal citations omitted ("La. PSC") v. Entergy.

[13] *Id*., citing *BP Pipelines*, 153 FERC ¶ 61,233 at PP 12-13 (citing *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985), *order on reh'g*, 32 FERC ¶ 61,112, *aff'd sub nom., Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986)).

[14] *New England Conf. of Pub. Utilities Commissioners, Inc.*, 124 FERC ¶ 61,291 (2008).

[15] *See Potomac-Appalachian Transmission Highline, LLC Alison Haverty*, 140 FERC ¶ 61,229, at P 79 (2012)(exploring the prudence of transmission-related ""lobbying costs, general advertising and outside services employed, Reliable Power Coalition's costs, double-counting of costs between FERC accounts, shared parent company costs among affiliates, membership costs, and donations and expenditures for civic, political and related activities . . . ."); *Louisiana Pub. Serv. Comm'n, Arkansas Pub. Serv. Comm'n, & Council of the City of New Orleans, Louisiana Sys. Energy Res., Inc., Entergy Servs., LLC, Entergy Operations, Inc., & Entergy Corp.*, 181 FERC ¶ 61,135 (2022)(in a generation-related proceeding, setting for hearing "the issue of the prudence of the 2012 Uprate, including Respondents' request for privileged treatment of the 2009 Investment Proposal").

interest holder of both plants, which operated the plants. While the minority interest holder sued the plant manager for the operation of the nuclear plant, FERC found that it was imprudent that the utility did not sue the manager for the operation of the coal plant. FERC noted that while it was hesitant to second-guess the utility and that it did not want to "encourage empty litigation," it could not conclude on the pleadings that the complainants met their burden, and it instituted a limited 206 investigation into the utility's prudence, and whether the investigation was barred by the terms of the Municipalities' settlements.[16] There appear to be no cases in the past 20 years in which the Commission has rejected as imprudent any transmission-related investment.

To show that a project is imprudent is highly-fact intensive and the burden of proof is nearly impossible to meet. Transmission owners do not have an affirmative obligation to establish that their projects are prudent before they can begin construction and pass the costs onto consumers, which occurs rather easily through transmission formula rates. PJM and the Ohio Transmission Utilities cannot reasonably rely on consumers' right to file prudence challenges as an effective check on Supplemental Project spending.

B. Formula Rate Transmission Protocols Are Not a Viable Option for Containing Supplemental Project Spending.

Formula Rate Transmission Protocols do not adequately protect consumers from imprudent Supplemental Project spending because, even under most protocols, the burden of denying cost recovery for Supplemental Project investment lies with the consumer, not the utility. Protocols do not give consumers an adequate opportunity to make a challenge to the proposed supplemental projects. The protocols provide no opportunity to compel transmission owners' responses to discovery. The protocols provide no opportunity to cross-examine utility witnesses about the

[16] *Towns & Cities of Clayton, Lewes, Middleton, Milford, New Castle, Newark, Seaford, & Smyrna, Delaware*, 72 FERC ¶ 61,289 (1995).

decisions to engage in Supplemental Project spending. Other problems involve the burden of proof being on the consumer and the burdens of exhausting all possible mechanisms for a challenge before a stakeholder can launch a Section 206 complaint. And even if the stakeholder successfully overcomes the burden of proof and exhausts its procedural options, the transmission owner has often proceeded with, or even completed, Supplemental Project construction, which places the Commission in a difficult position of denying cost recovery for a facility that has been placed in service. As a result, there is not an adequate opportunity to respond to and challenge a proposed Supplemental Project.

We analyze below the relevant sections of the Formula Rate Protocols of several of the transmission owners that have been named as respondents in the OCC's Complaint. Full copies of the Formula Rate Protocols are attached as exhibits to these Comments.

1. <u>AEP's Formula Rate Protocols</u>.

Formula rate protocols for Ohio Power Company are found in Attachment H-14A of the PJM Open Access Transmission Tariff, which is included in Exhibit A. Section 3.e.v of Attachment H-14A notes that the posting of the Net Revenue Requirement and True-Up Adjustment ("the Annual Update") are subject to prudence reviews and challenges, but the protocols explicitly state "that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges." Section 4 of Attachment H-14A establishes the "Annual Review Procedures." Paragraph (a) gives interested parties up to 210 calendar-days to make a challenge in writing. "An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge." Upon receipt of a challenge, AEP must appoint a senior representative to work with the party, and then AEP has

20 business days to respond. After each annual Publication date, interested parties have up to 150 calendar days for a "Discovery Period" to serve AEP with "reasonable information requests." Section 4.e.f. specifies,

> Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.

After AEP receives an information request, AEP has 15 business days to respond. Section 4.j. provides that challenges related to Accounting Changes shall be treated in the same manner as challenges to the Annual Update.

Section 5.a. gives parties 270 days after the Annual Update to file a formal challenge with FERC. Section 5.b requires Formal Challenges to be filed under the Protocols instead of under FPA Section 206. Among other requirements, the challenge must "set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including . . . the prudence of actual costs and expenditures . . . . " It is also worth mentioning that the scope of any challenge, whether formal or informal, includes only those issues that may be necessary to determine: (i) the extent or effect of an

Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. During a Formal Challenge proceeding, and pursuant to Section 5.f., AEP must show the justness and reasonableness of its rate by demonstrating that it has adhered to the Protocols. The formula rate transmission protocols for AEP Ohio Transmission Company are located in Attachment H-20A, which is included in Exhibit B, and includes the same language and process. The bottom-line is that consumers, not the utility, bear the burden of demonstrating the imprudence of Supplemental Project spending, and, unless the Commission sets a formal challenge for evidentiary hearing, consumers have no right to force or compel AEP to respond to discovery requests and have no right to cross-examine AEP witnesses.

2. ATSI's Formula Rate Protocols.

ATSI's formula rate protocols, contained in PJM Tariff Attachment H-21 and included in Exhibit C, are very similar to AEP's formula rate protocols with minor differences. The formula rate protocols have some serious issues in their design that make them inadequate at providing just and reasonable procedures in the determination of just and reasonable rates. Some key issues with the protocols are:

a. Formula rate protocols do not impose on the utility the burden of demonstrating the justness, reasonableness, or prudence of the costs being flowed through formula rates. This burden rests with the challenger.
b. There are no discovery responses provided under oath or affirmation.

c. No opportunities exist to compel discovery responses for utilities' inadequate answers. This issue creates an opportunity for the transmission owners to dodge the questions being asked and to frustrate the challengers' purpose of factfinding.
d. No opportunities exist for cross-examination of claims that purport to justify expenditures. Without an opportunity for cross-examination, there is no way to test the veracity and completeness of what is being represented.
e. Some protocols include provisions that require consumers to exhaust informal and formal challenge processes before filing a Section 206 complaint. ATSI's protocol has this problem. This issue makes it more cumbersome for challengers and can block significant challenges from being heard.
f. Projects are already built by the time that challenges or complaints are fully and finally resolved. As a result, the challengers will be paying rates to recover the costs of projects that may not have been needed in the first place.
g. There is no involvement by FERC Trial Staff in the annual rate update process. FERC Trial Staff engages in the initial establishment of transmission formula rates but has no role in the annual processes where actual costs flow through the formulas. Trial Staff's expertise is not available to consumers at this stage. And Trial Staff does not have the benefit of experiencing how transmission formula rates actually work in practice.

As a consequence of these deficiencies, challengers working under transmission formula rate protocols are forced to pay rates that may not be just and reasonable. The opportunities for meaningful participation in the ratemaking process are illusory, and it cannot be said that challengers have due process.

The Federal Power Act imposes an obligation that all transmission rates to be charged and paid are to be just and reasonable, and that the practices impacting those rates are also to be just and reasonable.[17] When customers must pay rates for Supplemental Projects that have costs that are not prudently incurred, with no effective means to challenge the prudency of the investment, rates are not just and reasonable.

[17] *See* 16 U.S.C. § 824d(a).

C. Substantial increases in Transmission Rates in the PJM Region Correlate Closely with Implementation of Transmission Formula Rates.

The inadequacies of the transmission formula rate regime are borne out by the substantial transmission rate increases that occur year-over-year following the implementation of transmission formula rates. And the problem is not limited to the Ohio Transmission Utilities. Increases in network integration transmission service ("NITS") rates in many of the PJM Zones, following the zonal adoption of a transmission formula rate, have far outpaced the rate of inflation. Below is analysis of the NITS rates that existed under a period when a transmission owner had in place a stated transmission rate and then the NITS rates that have been assessed each year since the implementation of transmission formula rates. The evidence is pretty clear that, even if the adoption of transmission formula rates is not the cause of the transmission rate increases, they must be a substantial contributing factor that warrants closer Commission scrutiny.

The chart below shows the rapid increases in NITS rates since AEP,[18] ATSI,[19] and, more recently, Dayton,[20] adopted transmission formula rates. In each graph, the red-hashed vertical line shows when the transmission formula rate went into effect. The step increases show the annual updates to the NITS rate that have occurred under the formulas.

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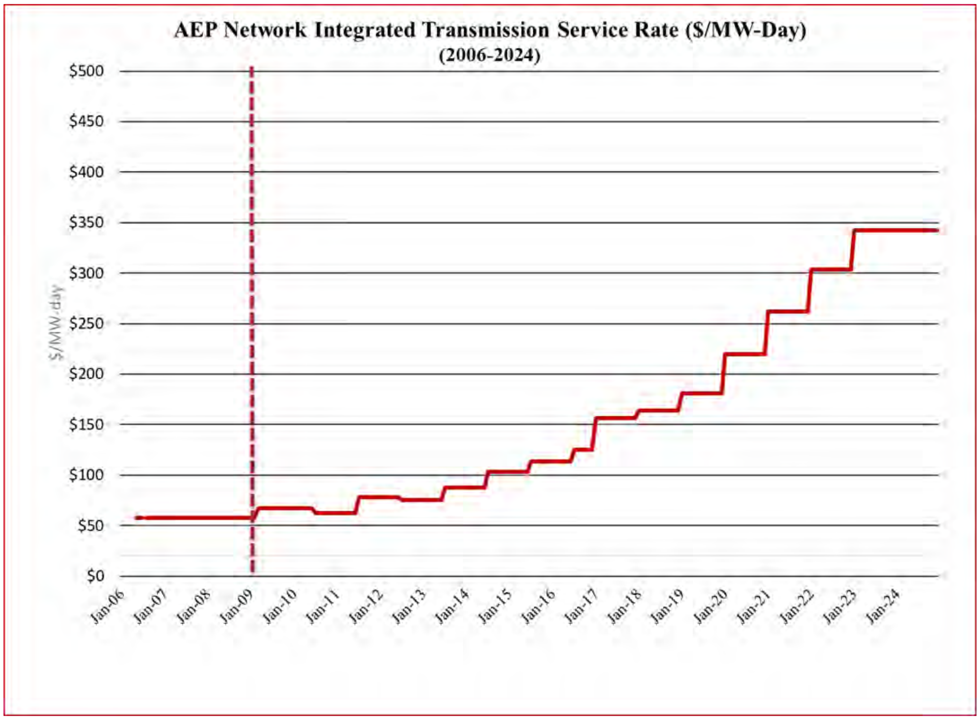
[18] *American Electric Power Service Corp.*, Exhibit AEP-303, PJM OATT Attachments H-14, H-14A, H-14B and pro forma Schedules 1A, 7 and 8 Black-lined Version, Attachment H-14, First Revised Sheet No. 314B.01 at P 1, Docket No. ER08-1329-000 (filed July 31, 2008); *American Electric Power Service Corp.*, Supplemental Filing, Formula Rate Update for AEP East Operating Companies in PJM to be Effective July 1, 2010 through June 30, 2011, Docket No. ER08-1329-000 (filed June 8, 2010); *American Electric Power Service Corp.*, Supplemental Filing, Attachment A, Formula Rate Update for AEP Transmission Company subsidiaries in PJM to be Effective July 1, 2010 through June 30, 2011, Docket No. ER10-355-000 (filed June 8, 2010); PJM, Formula Rates, 2012-2024, *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023).

[19] OASIS, Historical Rate Information, 2006-2009, *available at* https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Historical_Rate.html (last visited Nov. 16, 2023); *American Transmission Systems, Inc.*, Amendment to 2011 Transmission Formula Rate Annual Update, Attachment A, Attachment H-21A at p. 1, lines 16-16a, Docket No. ER11-3508-001 (filed July 14, 2011); *American Transmission Systems, Inc.*, 2012 Transmission Formula Rate Annual Update, Attachment A, Attachment H-21A at p. 1, lines 16-16a, Docket No. ER11-3508-000 (filed May 1, 2012); *American Transmission Systems, Inc.*, Amendment to 2013 Transmission Formula Rate Annual Update, Attachment A, Attachment H-21A at p. 1, lines 16-16a, Docket No. ER11-3508-001 (filed May 21, 2013); *American Transmission Systems, Inc.*, 2014 Transmission Formula Rate Annual Update, Attachment H-21A at p. 1, lines 16-16a, Docket No. ER11-3508-000 (filed May 1, 2014); *American Transmission Systems, Inc.*, 2017 PTRR Informational Filing, Attachment B, Attachment H-21A at p. 1, line 16, Docket No. ER17-1546-000 (filed May 1, 2017); *American Transmission Systems, Inc.*, 2018 PTRR Informational Filing, Attachment B, Attachment H-21A at p. 1, line 16, Docket No. ER18-1524-000 (filed May 1, 2018); *American Transmission Systems, Inc.*, 2019 PTRR Informational Filing, Attachment B, Attachment H-21A at p. 1, line 16, Docket No. ER19-1767-000 (filed May 1, 2019); *American Transmission Systems, Inc.*, 2020 PTRR Informational Filing, Attachment B, Attachment H-21A at p. 1, line 16, Docket No. ER20-1756-000 (filed May 1, 2020*); American Transmission Systems, Inc.*, Projected Transmission Revenue Requirement for Rate Year 2021, Attachment H-21A at p. 1, line 16 *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023); *American Transmission Systems, Inc.*, 2022 PTRR, Attachment H-21A at p. 1, line 16, *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023); *American Transmission Systems, Inc.*, 2023 PTRR Informational Filing, Attachment B, Attachment H-21A at p. 1, line 16, Docket No. ER23-1868-000 (filed May 1, 2023); PJM, Formula Rates, *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023);

[20] *Alcoa Power Generating Inc. – Long Sault Division, et al.*, Order Accepting Revisions to Stated Transmission Rates in Response to the Commission's Order to Show Cause and Terminating Section 206 Proceedings, 165 FERC ¶ 61,094 (2018); *The Dayton Power and Light Company*, Application to Establish a Formula Transmission Rate at pp. 4-5 and Attachment 2 "Red-Line" Tariff Pages, Attachment H-15 at p. 46, Docket No. ER20-1150-000 (filed Mar. 3, 2020); *The Dayton Power and Light Company*, Offer of Settlement at I.E., Attachment 7, Attachment H-15A at line 174, and Attachment 8, Attachment H-15A at line 174, Docket No. ER20-1150-000 (filed Dec. 10, 2020); PJM, Formula Rates, 2021-2024, *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023).


AEP Network Integrated Transmission Service Rate ($/MW-Day)
(2006-2024)
$/MW-day
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Jan-06
Jan-07
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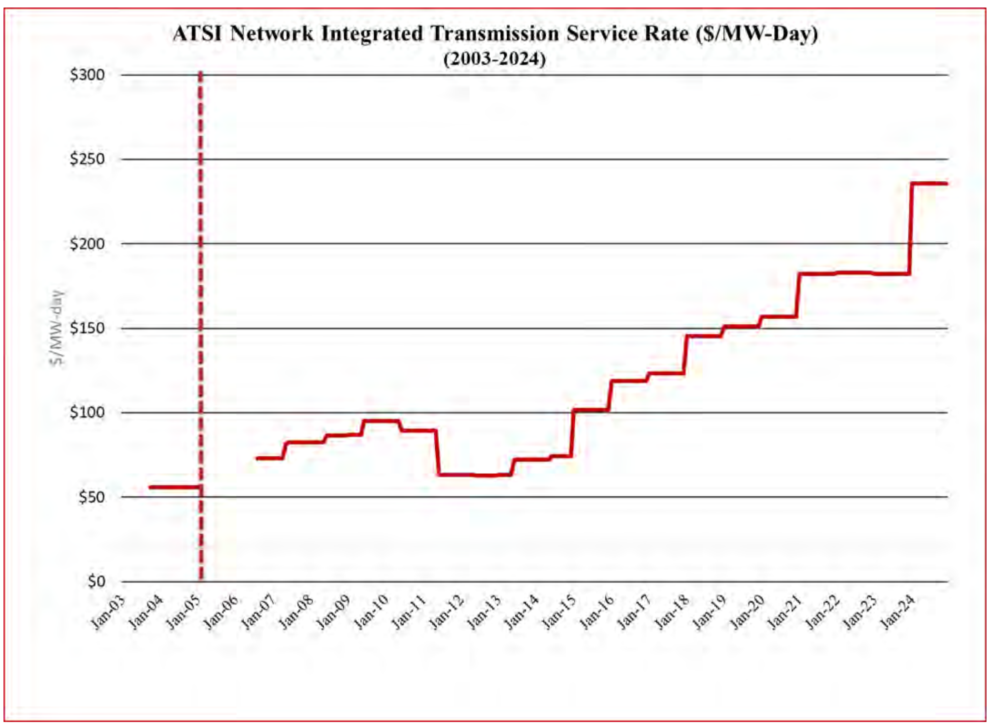
ATSI Network Integrated Transmission Service Rate ($/MW-Day)
(2003-2024)
$/MW-day
$300
$250
$200
$150
$100
$50
$0
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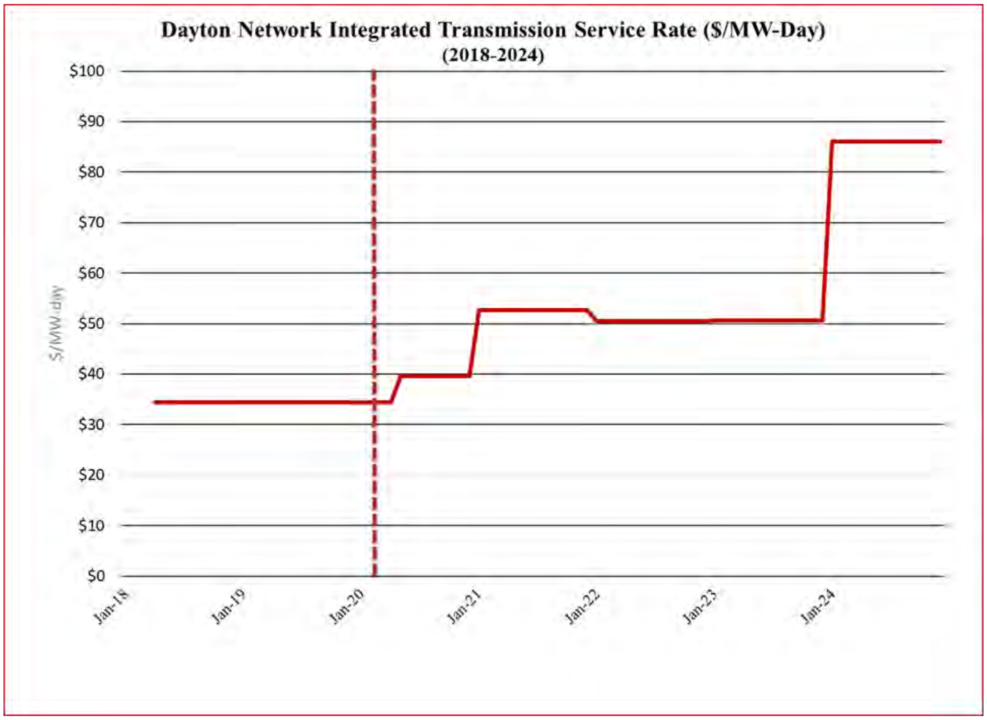

And the problem is not unique to the State of Ohio. The zone in the PJM Region that has experienced the most dramatic NITS rate increases is the Public Service Electric and Gas Company ("PSEG") zone. The vertical red-hashed line shows the effective date of the PSEG transmission formula rate.[21] As the graph illustrates, PSEG NITS rates were stable for the six years prior to the adoption of a transmission formula rate.[22] NITS rates since the adoption of a transmission formula rate have increased by about $160,000/MW-Year (eight-fold or 800%) between January 2003 and January 2024.[23] On average, that is an increase of $7,619.05/MW/year each year over a 20-year horizon.

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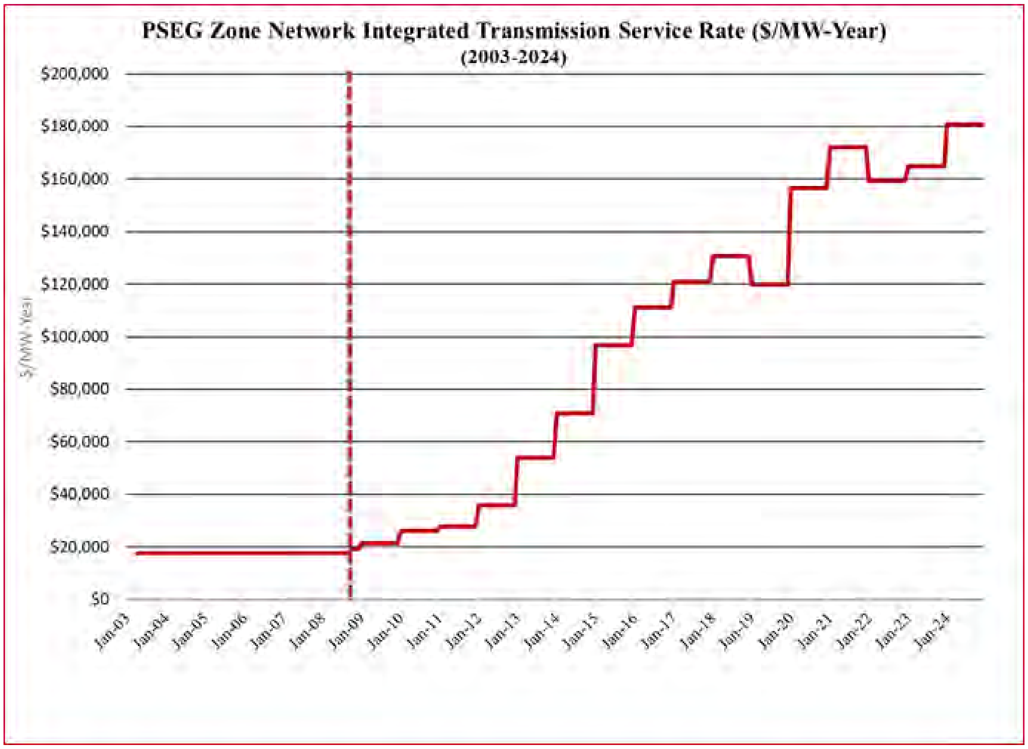
[21] *Pub. Serv. Elec. and Gas Co.*, Order on Formula Rate Proposal, 124 FERC ¶ 61,303 at PP 1, 10 (2008).

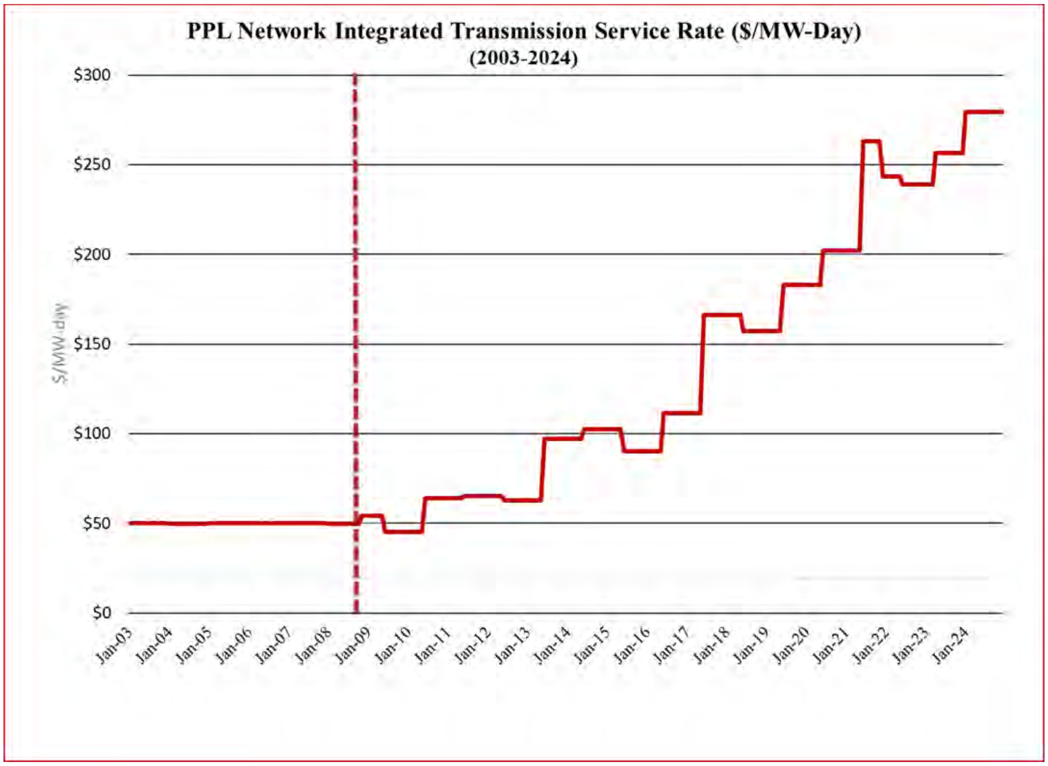
[22] *Pub. Serv. Elec. and Gas Co.*, Formula Rate Filing, Appendix B, Original Sheet No. 311 Effective Mar. 20, 2002, Attachment H-10 at P 1, Docket No. ER08-1233-000 (filed July 7, 2008).

[23] *Id.*, Appendix C, Exhibit No. PEG-4 at p. 4, line 167; *Pub. Serv. Elec. and Gas Co.*, 2009 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER08-1233-000 (filed Oct. 15, 2008); *Pub. Serv. Elec. and Gas Co.*, 2010 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 7, 2009); *Pub. Serv. Elec. and Gas Co.*, 2011 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2010);



Pub. Serv. Elec. and Gas Co., 2012 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 17, 2011); *Pub. Serv. Elec. and Gas Co.*, 2013 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2012); *Pub. Serv. Elec. and Gas Co.*, 2014 Formula Rate Modified Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Dec. 13, 2013); *Pub. Serv. Elec. and Gas Co.*, 2015 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2014); *Pub. Serv. Elec. and Gas Co.*, 2016 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2015); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2017 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 17, 2016); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2018 Formula Rate Annual Update (Errata), Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 27, 2017); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2019 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2018); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2020 Formula Rate Annual Update (Second Revision), Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Jan. 17, 2020); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2021 Formula Rate Annual Update (Revision), Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 22, 2021); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2022 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 15, 2021); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2023 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 17, 2022); *Pub. Serv. Elec. and Gas Co.*, Informational Filing of 2024 Formula Rate Annual Update, Attachment H-10A, Formula Rate-Appendix A at line 167, Docket No. ER09-1257-000 (filed Oct. 16, 2023).

A similar but, to date, less severe phenomenon exists in the PPL Zone,[24] where the adoption of formula transmission rates has correlated with a 560% increase in transmission rates over a similar time period.



In Industrial Customers' experience, the problem is not with the Excel spreadsheet that provides the formulas for calculating the rate. The problem is with the lack of discipline on the incurrence of the costs that are flowing through that formula. As the Complaint argues, and as experience and the analysis above shows, the transmission formula rate regime provides no effective check

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[24] *PPL Elec. Utils. Corp.*, Revised Tariff Sheets to the PJM Interconnection, L.L.C. Open Access Transmission Tariff, Appendix C, PPL Electric Utilities Corp. Attachment H-8 (Redline version), Second Revised Sheet No. 307 at P 1, Docket No. ER08-1457-000 (filed Aug. 28, 2008); *PPL Elec. Utils. Corp.*, Offer of Settlement, Appendix D Populated Formula Rate, Attachment H-8G at p. 4, line 151, Docket No. ER08-1457-000, *et al*. (filed May 1, 2009); *PPL Elec. Utils. Corp.*, Informational Filing of 2009 Formula Rate Annual Update, Exhibit 1, Attachment H-8G at p. 1, line 151 (Docket No. ER08-1457-000, *et al.* (filed May 15, 2009); *PPL Elec. Utils. Corp.*, Errata to Informational Filing of 2010 Formula Rate Annual Update, Exhibit 1, Attachment H-8G at p. 4, line 151, Docket No. ER09-1148-000 (filed May 18, 2010); PJM, Formula Rates, 2011-2024, *available at* https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates (last visited Nov. 16, 2023).

on the level of Supplemental Project spending and, as a consequence, consumers have been hit with meteoric rises in NITS rates in many zones in the PJM Region.

D. The Attachment M-3 Process Is Not a Viable Option for Containing Supplemental Project Spending.

There are also severe deficiencies in the Commission-mandated PJM stakeholder processes for review of Supplemental Projects, which is contained in PJM Tariff Attachment M-3 ("M-3 Process"), that make the process woefully inadequate. A copy of Attachment M-3 of the PJM Tariff is attached as Exhibit D.

First, while the M-3 Process prescribes a "Needs Meeting" for the purpose of reviewing the need for each Supplemental Project, the M-3 Process does not have any requirements for how much information a transmission owner must provide during such a Needs Meeting. Section C.3 of Attachment M-3 provides:

> No fewer than 25 days after the Assumptions Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review the identified criteria violations and resulting system needs, if any, that may drive the need for an Attachment M-3 Project (Needs Meeting). Each Transmission Owner will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and models that it uses to plan Attachment M-3 Projects. The Transmission Owners shall share and post their identified criteria violations and drivers no fewer than 10 days in advance of the Needs Meeting. Stakeholders may provide comments on the criteria violations and drivers to the Transmission Owner for consideration prior to, at, or following the Needs Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Needs Meeting and may respond or provide feedback as appropriate.

Experience has shown that the identified drivers are often vague, generic, and non-descriptive, communicating information of little to no value for identifying the project and highlighting the benefits to the transmission system. It could take a few years for projects to address identified drivers including "performance and risk." For example, during the Western Subregional meeting on April 21, 2023, FirstEnergy (APS) presented three solutions that had already been completed. Those solutions are attached as Exhibit E (APS-2021-007, 008, 009 pages 12-15). As a result, the transmission owners are able to go through the motions of complying with the M-3 Process, while not actually demonstrating a tangible and concrete need for the Supplemental Projects. And the posting of the inadequate information and stakeholders' opportunity to probe that information all must occur within a 20-day period. Because the information that the transmission owners provide suffers from these issues, stakeholders are unable to meaningfully review and engage with these projects.

Second, it has become more common for solutions to be presented after the projects are completed. The recourse for these situations is not clear. As an example, FirstEnergy (MAIT) introduced a need and solution for Penelec - PN-2023-014 and 015. Need 014 was completed in November 2022, but the Needs Meeting occurred on September 14, 2023, and the Solution Meeting was held on October 19, 2023. Need 015 was already under construction at the time of those meetings, and is estimated to be completed by November 29, 2023, a little more than a month after the Solution Meeting. In that instance, FirstEnergy provided two solutions that were already under construction or completed without review or an opportunity for the projects to face scrutiny.

Third, in an analysis of the submitted Supplemental Projects for April 2023, attached as Exhibit H, there was a total of 23 projects submitted with an estimated cost of $476.38 million. Of these 23 projects, 16 solutions, representing an estimated cost of $195.78 million, have no state Commission oversight.[25] During the subregional discussions, attached as Exhibit G, the relevant transmission owners were asked for information relating to how the estimated cost figure was developed; a breakdown of the project budget; and whether there was any oversight from state

[25] See Exhibit H.

utility commissions.[26] The answers from each of the transmission owners were incredibly generic and failed to provide any insight that would be helpful to answering the inquiries. For example, the transmission owners stated, in response to questions about cost estimates, that they use "industry-standard cost estimation practices," that are "based on initial scope of work assumptions." These descriptions tell us nothing about how the transmission owners actually made the calculations about cost and cost-effectiveness, and what they assumed in their models, assuming they even used some form of modelling for evaluating cost-effectiveness. The answers to the project budget question suffer from similar defects. And the question to whether there is state oversight is often answered with a standard two-sentence response that essentially states that the answer is "codified in state law and is publicly available" and the "[insert transmission owner here] will obtain all necessary approvals required by state law." These types of responses are not meaningful, yet they occur frequently in the M-3 Process, ostensibly because there is no consequence for providing inadequate responses. Indeed, the transmission owners would be hard-pressed to identify substantial investments that were not implemented as a result of scrutiny applied during the M-3 Process. The Commission cannot rely on the M-3 Process as an answer to the regulatory gaps and process deficiencies that the Complaint identifies.

E. The Problem With Supplemental Projects is Not Unique to Ohio – Few States in PJM Have Sufficiently Thorough Review Procedures to Ensure that the Resulting Transmission Rates are Just and Reasonable.

While there are a few exceptions, where state procedures for evaluating new transmission projects exist, those procedures generally focus only on the need for the project and do not scrutinize the cost estimates or the cost-effectiveness of new transmission projects. Nor should

[26] See Exhibit G.

they. The regulation of the rates for the transmission of electric energy in interstate commerce rests solely on FERC's shoulders.

Below is a brief survey of the laws governing state commission review of new transmission projects.

Delaware.

In Delaware, CPCNs are required for electric utilities that begin service.[27] Factors that the Commission considers in granting the certificate include:

1. Whether PJM Interconnection, L.L.C. (or its successor) ("PJM") has selected the applicant to develop or own transmission facilities included in the regional transmission expansion plan approved through PJM's Federal Energy Regulatory Commission-approved developer qualification and competitive procurement process, or if such PJM approval has not occurred:

    a. The demonstrated experience, operating expertise, and long-term viability of the applicant or its affiliates, partners, or parent company;
    b. The need for and impact of any transmission facilities proposed by the applicant on the safe, adequate, and reliable operation or delivery of electric supply services; and
    c. The engineering and technical design of any transmission facilities proposed by the applicant; and
    d. The impact of granting the certificate of public convenience and necessity application on the State's economy and the benefits to the State's ratepayers; and
    e. The impact of granting the certificate of public convenience and necessity application on the health, safety, and welfare of the general public.[28]

However, to expand a transmission facility requires a hearing. The Commission must determine whether the extension is "reasonable and practicable and will furnish sufficient revenue to justify the construction and maintenance of the same, and when the financial condition of the public utility

[27] See DEL. CODE. ANN. tit. 26, §203E.

[28] *Id.*

reasonably warrants the original expenditures required in order to make and operate such extension . . . . "[29] Criteria that the Commission is required to evaluate include "the size and amount of additional and potential customers to be served, whether the new customers will contribute to any capital expenditures required by the extension and whether the public utility must borrow funds to provide the extension of service."[30] However, and importantly, "these regulations shall not be construed to require any public utility to secure an Electric Transmission Supplier Certificate for any construction, modifications, upgrades, or extensions within the perimeter of any territory already served by it."[31]

Illinois.

"A certificate of public convenience and necessity requiring the transaction of public utility business in any area of this State shall include authorization to the public utility receiving the certificate of public convenience and necessity to construct such plant, equipment, property, or facility as is provided for under the terms and conditions of its tariff and as is necessary to provide utility service and carry out the transaction of public utility business by the public utility in the designated area."[32] However, new facilities require a CPCN before construction can begin, and the decision for the Commerce Commission to issue the CPCN requires a hearing.[33] The criteria that the utility must show to obtain the CPCN from the Commerce Commission are:

> i. that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers or that the proposed construction will promote the development of an effectively competitive electricity market that operates efficiently,

[29] *Id*. at § 204.

[30] *Id*.

[31] *Id*. at § 4.0.

[32] 220 ILCS 5/8406(a).

[33] *See Id*. at (b).

is equitable to all customers, and is the least cost means of satisfying those objectives; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and

ii. that the utility is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers.[34]

The statute requires the Commerce Commission to "attach primary weight to the cost or cost savings to the customers of the utility. The Commission may consider any or all factors which will or may affect such cost or cost savings, including the public utility's engineering judgment regarding the materials used for construction."[35] However, a CPCN is not required for 'high voltage electric service lines,' which means that the electric line has a design voltage of 100 kV or more when the utility is replacing or upgrading the high voltage electric line and related facilities; when the line and related facilities are being relocated to accommodate construction or expansion of transportation infrastructure; or when the high voltage electric service line and related facilities is constructed to serve a single customer or interconnect a generator to the public utility's transmission system provided that the interconnection customer has a right of way or owns the underlying property.[36] For expedited review of an application for a CPCN, one of the requirements is for the utility to provide all: "(iv) assumptions, bases, formulae, and methods used in the development and preparation of the diagrams and accompanying data, and a technical description . . . ."[37] The utility must also show that it held 3 pre-filing meetings to receive public comment in each county where the Project is to be located.[38]

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[34] *Id.*

[35] *Id*. at (d).

[36] *See Id*. at (g)(1)-(3).

[37] *Id*. at § 8-406.1(a)(1)(B)(iv).

[38] *Id*. at (a)(3).

Indiana.

Indiana has no CPCN required for electric transmission lines. It is only required for power generation projects. For example,

> Every public utility is required to furnish reasonably adequate service and facilities . . . The commission, in order to expedite the determination of rate questions, or to avoid unnecessary and unreasonable expense, or to avoid discrimination in rates between classes of customers, or, whenever in the judgment of the commission public interest so requires, may, for ratemaking and accounting purposes, or either of them, consider a single municipality and/or two (2) or more municipalities and/or the adjacent and/or intervening rural territory as a regional unit where the same utility serves such region, and may within such region prescribe uniform rates for consumers or patrons of the same class.[39]

However, the regulatory commission must hold a hearing and declare that a second public utility is required where equipment is already operated by a preexisting public utility under a license, franchise, or permit in a municipality and a second utility wishes to own, manage, control, or operate any other equipment.[40] In Indiana, there is no hearing, no burden of proof on the utility, no discovery, and no cross-examination of witnesses to determine if there is a public need for the Supplemental Project.

Kentucky.

Kentucky requires a utility to hold a CPCN before it can begin constructing equipment or facilities used to furnish utility service to the public.[41] However, a CPCN is not required for "ordinary extensions of existing systems in the usual course of business."[42] Electric transmission lines that are 138 kV or more or greater than 5,280 feet (1 mile) in length is not an ordinary

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[39] Ind. Code Ann. § 8-1-2-4 (West).

[40] *See* Ind. Code Ann. § 8-1-2-86 (West).

[41] Ky. Rev. Stat. § 278.020(1)(a)(1).

[42] *Id*. at (1)(a)(2).

extension of an existing system in the ordinary course of business, and they do require a CPCN.[43] Ordinary extensions of existing systems in the usual course of business, for which no CPCN is required, include replacements or upgrades to existing electric transmission lines, relocations of lines to accommodate transportation infrastructure; or transmission lines constructed to serve a single customer and that passes over the customer's property.[44] Kentucky's administrative regulations further defines 'extensions in the ordinary course of business' for which CPCNs are not required, as "extensions that do not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates of service of other utilities . . . that are in the general or contiguous area in which the utility renders service, and that do not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved, or will not result in increased charges to customers."[45]

Maryland.

Maryland Annotated Code, Public Utilities § 7-207(b)(3)(i) provides, "unless a certificate of public convenience and necessity for the construction is first obtained from the Commission, a person may not begin construction of an overhead transmission line that is designed to carry a voltage in excess of 69,000 volts or exercise a right of condemnation with the construction."[46] "Construction" refers to:

i. any physical change at a site, including fabrication, erection, installation, or demolition; or
ii. the entry into a binding agreement or contractual obligation to purchase equipment exclusively for use in construction in the State or to undertake a program of actual construction in the State which cannot be canceled or

[43] Ky. Rev. Stat. § 278.020(2).

[44] *Id*. at (a)-(c).

[45] 807 KAR 5:0001, Section 15(3).

[46] Maryland Annotated Code, Public Utilities, § 7-207(b)(3)(i).

> modified without substantial loss to the owner or operator of the proposed generating station."[47]

The Commission may waive the requirement for a CPCN if the construction of an overhead transmission line greater than 69 kV does not: "1. require the person to obtain new real property or additional rights–of–way through eminent domain; or 2. require larger or higher structures to accommodate: A. increased voltage; or B. larger conductors."[48] After the Commission receives an application for a CPCN, notice is provided to a list of interested stakeholders, and then the Commission holds a public comment period and public hearing.[49] When the Commission evaluates a CPCN for a transmission line, along with several other criteria, the Commission considers the economics of the project as well as the "need to meet existing and future demand for electric service; and . . . the alternative routes that the applicant considered, including estimated capital and operating costs of each alternative route and [an explanation] why the alternative route was rejected."[50] For the Commission to issue a CPCN, the statute requires a vote of the majority of Commission members, and failure to reach a majority vote will cause the application to be denied.[51]

Michigan.

Construction of a major transmission line shall not begin until the Commission issues a CPCN.[52] A "major transmission line" is "a transmission line of 5 miles or more in length wholly or partially owned by an electric utility, affiliated transmission company, or independent

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[47] *Id*. § 7-207(a)(3)(i)(1)-(2).

[48] *Id*. § 7-207(b)(4)(i)(1-2).

[49] *Id*. § 7-702(c)-(d).

[50] *Id*. § 7-207(e)-(f).

[51] *Id*. § 2-208(h).

[52] Electric Transmission Line Certification Act, § 460.565.

transmission company through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more."[53] The applicant for a CPCN "shall schedule and hold a public meeting in each municipality through which a proposed major transmission line for which a plan has been submitted under section 4 would pass."[54] To issue a CPCN, The Commission needs to determine:

> i. The quantifiable and nonquantifiable public benefits of the proposed major transmission line justify its construction.
> ii. The proposed or alternative route is feasible and reasonable.
> iii. The proposed major transmission line does not present an unreasonable threat to public health or safety. [and]
> iv. The applicant has accepted the conditions contained in a conditional grant.[55]

Another requirement for a granted application is for the CPCN to contain a cost estimate for the transmission line. Only reasonable and prudent costs of the transmission line are to be recovered in rates, even if those costs exceed the cost estimate included in the CPCN.[56]

<u>New Jersey.</u>

New Jersey does not require a CPCN for electricity transmission projects.[57]

<u>North Carolina.</u>

In North Carolina, a CPCN is required before a public utility or person can initiate construction of a new transmission line.[58] However, relevant types of projects that do not require a CPCN for construction include: a line with capacity less than 161 kV; "the replacement or expansion of an existing line with a similar line in substantially the same location, or the rebuilding, upgrading, modifying, modernizing, or reconstructing of an existing line for the purpose of

[53] *Id*. § 460.562(g).

[54] *Id*. § 460.566(1).

[55] *Id*. at (5).

[56] *See* § 460.572.

[57] *See generally* 48 NJ St. Ch. 4; *see also generally* 48 NJ St. Ch. 13A.

[58] N.C. Gen. Stat. Ann. § 62-101(a) (West).

increasing capacity or widening an existing right-of-way;" and a transmission line within FERC's licensing jurisdiction provided that FERC has conducted a "substantially equivalent" proceeding to the state's proceeding.[59] North Carolina also allows the Commission to waive notice and hearing requirements when the purpose of the transmission line is "to connect an existing transmission line to a substation, to another public utility, or to a public utility customer when any of these is in proximity to the existing transmission line."[60] In addition, the Commission can approve an applicant to start initial construction activities if the "circumstances require immediate action."[61] However, in such case, the applicant assumes the risk and the Commission is not bound to ultimately grant the CPCN.[62]

Ohio.

Because the Complaint discusses the CPCN review process for Ohio, the Industrial Customers do not repeat here the contents of the Complaint. For a discussion of Ohio's procedure for reviewing CPCNs and the shortcomings of the procedure, see Section IV.B of the Complaint.

Pennsylvania.

In Pennsylvania, only when a utility obtains a CPCN may it begin to "offer, render, furnish, or supply" service.[63] To grant a CPCN, "the commission shall find or determine that the granting of such certificate is necessary or proper for the service, accommodation, convenience, or safety of the public," and the Commission may impose conditions that it finds to be just and reasonable."[64] To make the determination, the Commission must hold public hearings "make such

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[59] § 62-101(c)(1)-(3).

[60] § 62-101(d)(1)(b).

[61] § 62-101(e).

[62] *Id*.

[63] 66 Pa. Stat. and Cons. Stat. Ann. § 1102(a)(1) (West).

[64] § 1103(a).

inquiries, physical examinations, valuations, and investigations, and may require such plans, specifications, and estimates of cost, as it may deem necessary or proper in enabling it to reach a finding or determination."[65] When a utility builds a new transmission line, the utility applies to the Commission for authorization to locate and construct a high-voltage transmission line (also referred to as an HV line).[66] A high-voltage transmission line is defined as "an overhead electric supply line with a design voltage greater than 100,000 volts."[67] However, instead of applying to the Commission to build the line, a utility can file a "letter of notification" to the Commission. Letters of notification apply to HV lines that are proposed to be located entirely on an existing transmission right-of-way, for existing lines proposed for voltage increases, and for HV lines to be reconductored or reconstructed, so long as the size, character design, or configuration of the proposed HV line does not substantially alter the right-of-way. Letters of notification also contain some of the requirements for applications listed above, namely requirements (3) and (5).[68] If the Commission approves a letter of notification, the utility can begin construction without applying to the Commission, but if it is rejected, then the utility must apply to the Commission.[69] In the case that the utility applies to construct the line, then there is a public hearing, where the Commission will consider:

i. The present and future necessity of the proposed HV line in furnishing service to the public.
ii. The safety of the proposed HV line.
iii. [the environmental impacts of the project]
iv. the availability of reasonable alternative routes. [70]

[65] § 1103(a).

[66] § 57.71.

[67] § 57.1.

[68] § 57.72(d)(1)-(4).

[69] § 57.72(d)(5).

[70] § 57.75(e)(3).

It is also noteworthy that the utility can petition for, and the Commission can accept, expedited consideration of the application.[71] For the Commission to grant the application for the proposed HV line, it must find that:

> i. That there is a need for it.
> ii. That it will not create an unreasonable risk of danger to the health and safety of the public.
> iii. That it is in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth.
> iv. That it will have minimum adverse environmental impact, considering the electric power needs of the public, the state of available technology and the available alternatives.[72]

Tennessee.

Before a public utility can construct a line, it must obtain a CPCN. It must file a written application with the Commission, and the Commission must conduct a public hearing.[73] The Commission will not grant the CPCN if the proposed facilities compete with existing facilities, unless the existing facilities "are inadequate to meet the reasonable needs of the public . . . ."[74] During the hearing, the applicant is required to file engineering plans "and other information fully descriptive of the proposed development . . . ."[75] Evidence presented during the hearing is to be taken under oath, and is admissible in any court.[76]

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[71] § 57.75(g).

[72] § 57.76(b).

[72] Tenn. Code Ann. § 65-4-201 (West).

[73] § 65-4-203(a).

[74] § 65-4-204.

[74] *See* § 65-4-205.

[74] § 65-4-208.

[74] Va. Code Ann. § 56-265.2(A)(1) (West).

[74] *Id*.

[75] § 65-4-204.

[76] *See* § 65-4-205.

When a public utility that was not engaged in the electric utility industry on March 22, 1955, proposes to extend or construct a facility, the entity needs to apply for a CPCN. The Commission is required to reject the application if granting the CPCN is not in the public interest.[77]

Virginia.

In general, it is "unlawful for any public utility to construct, enlarge or acquire, by lease or otherwise, any facilities for use in public utility service, except ordinary extensions or improvements in the usual course of business, without first having obtained a certificate from the Commission that the public convenience and necessity require the exercise of such right or privilege."[78] The Commission can only approve a CPCN after there is a hearing with notice provided to the interested parties.[79] If the utility proposes the extension to be built outside of its territory, it must file a map showing the location of the extension, and if the utility will construct and operate the extension, the project must not interfere with the service of other public utilities. Regardless of the size of the proposed transmission facility, the Commission must consider environmental reports issued by other state agencies, local comprehensive plans, the impact on economic development, and improvements in reliability before approving construction of electrical utility facilities.[80]

For transmission line extensions that have a capacity of 138 kV or greater, the Commission must send various stakeholders a "written description of the proposed route the line is to follow, as well as a map or sketch of the route including a digital geographic information system (GIS)

[77] § 65-4-208.

[78] Va. Code Ann. § 56-265.2(A)(1) (West).

[79] *Id*.

[80] *See generally* § 56-46.1(A).

map provided by the public utility showing the location of the proposed route."[81] Before approving the project, the Commission determines whether the line is needed, and it verifies the applicant's load flow modeling, contingency analyses, and reliability needs.[82] And the Public Utility must "provide adequate evidence that existing rights-of-way cannot serve the needs of the company."[83]

West Virginia.

A CPCN is required to begin construction of a high voltage transmission line of 200 kV or more, when the line is "not an ordinary extension of an existing system in the usual course of business."[84] Following the application, the applicant publishes notice and then the Commission will hold a public hearing to determine whether the line and its location are in the public interest.[85] The Commission may approve the utility's proposal if it finds that the transmission line:

i. Will economically, adequately and reliably contribute to meeting the present and anticipated requirements for electric power of the customers served by the applicant or is necessary and desirable for present and anticipated reliability of service for electric power for its service area or region;
ii. Will be in the best interest of West Virginia customers and its citizens; and
iii. Will result in an acceptable balance between reasonable power needs and reasonable environmental factors.[86]

While granting a CPCN for a transmission line that has a completion date more than a year from the date of the grant of the CPCN, the Commission can subject the project to a continuing prudence review.[87]

[81] § 56-46.1(B).

[82] *Id*.

[83] § 56-46.1(C).

[84] W. Va. Code Ann. § 24-2-11a(a) (West).

[85] § 24-2-11a(c).

[86] § 24-2-11a(d).

[87] § 24-2-11b.

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As evident, state processes for reviewing CPCNs vary widely, ranging from no review at all and no opportunities for the public to challenge the projects to full-fledged hearings with wide opportunities for discovery and cross-examination. In cases where states do require CPCNs for certain transmission facilities, those CPCN requirements do not apply to lower-voltage transmission facilities, reconstruction ("wreck and rebuild") projects, reconductoring projects, or extensions within existing rights of way. Yet these types of projects comprise the bulk of the transmission owners' Supplemental Project spending. That may be a coincidence, and that may not be a coincidence. The bottom-line is that very few state commissions in the PJM Region have procedural safeguards in place to determine that Supplemental Projects are both necessary and cost-effective. That responsibility lies with this Commission, which certainly has the statutory authority to evaluate both.

IV. FERC HAS OPTIONS FOR SETTING THE JUST AND REASONABLE REPLACEMENT RATE.

The Commission has exclusive jurisdiction to set the just and reasonable rate for interstate electric transmission service provided by jurisdictional public utility transmission owners.[88] FERC may exercise its authority by acting on tariffs filed by transmission owners or, where appropriate, by initiating a proceeding to set a new rate, charge, or classification where the existing one has become unjust, unreasonable, unduly discriminatory, or preferential.[89] The Commission's

[88] *See* 16 U.S.C. §§ 824(d), 824e; *New York v. FERC*, 535 U.S. 1, 22 (2002).

[88] *Id*.

[89] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 56, 70, 75-76 (D.C. Cir. 2014); *see also Trans. Access Policy Grp. v. FERC*, 225 F.3d 667, 687 (D.C. Cir. 2000).

[89] Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285, 65 Fed. Reg. 809, 904 (Jan. 6, 2000), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), 65 Fed. Reg. 12,088 (Mar. 8, 2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). See also 18 C.F.R. § 35.34(k)(6).

remedial authority is not confined to setting the new just and reasonable rate, but also extends to transmission planning and cost allocation practices.[90] Through orders and regulations, the Commission has successfully used its remedial authority under the Federal Power Act to mandate certain market monitoring functions in RTO and ISO regions, while relying on the same statutory provisions that govern its ratemaking authority over the transmission and sale of electric energy in interstate commerce.[91]

A. The OCC Recommendations.

The Complaint proposes a few solutions to the problems caused by the current lack of review process for Supplemental Projects. Solutions proposed included amending the PJM tariff; developing an Independent Transmission Monitor; using a stated-rate approach for transmission projects; and having FERC develop its own solution to ensure just and reasonable rates, should FERC reject the other proposed solutions. Several of these options have merit, but none provide the full scope of relief that the Industrial Customers' Recommendation would provide.

1. Amending PJM's Tariff to Require FERC's Approval of Supplemental Projects.

Section F.1 of the Complaint proposes that FERC should amend the PJM Tariff to require the Ohio Transmission Owners to file with FERC for approval of local transmission projects that are being planned each year prior to beginning construction of any of those projects. Industrial Customers agree that there should be a fix in PJM's Tariff. However, the current deficiencies in the formula ratemaking protocols discussed above make it unlikely that the proposal will be

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[90] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 56, 70, 75-76 (D.C. Cir. 2014); *see also Trans. Access Policy Grp. v. FERC*, 225 F.3d 667, 687 (D.C. Cir. 2000).

[91] Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285, 65 Fed. Reg. 809, 904 (Jan. 6, 2000), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), 65 Fed. Reg. 12,088 (Mar. 8, 2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). See also 18 C.F.R. § 35.34(k)(6).

effective on its own. Ultimately, this proposal needs to be paired with amendments to the PJM Tariff to address the current deficiencies in each transmission owner's formula rate transmission protocols by:

1. Imposing on TOs the burden of demonstrating the justness, reasonableness, or prudence of the costs being flowed through formula rates;
2. Requiring discovery responses to be provided under oath so that other parties can verify the representations for accuracy and validity;
3. Establishing procedurally expeditious opportunities to compel discovery responses for inadequate discovery responses;
4. Providing opportunities for cross-examination of claims that purport to justify expenditures;
5. Removing all provisions in current protocols that require consumers to exhaust informal and formal challenge processes before filing a Section 206 complaint;
6. Preventing construction of projects until after challenges or complaints are fully and finally resolved; and
7. Facilitating involvement by FERC Trial staff in the annual rate update process.

While Industrial Customers generally oppose the use of formula transmission rates, any continuation of the formula rate regime should include the safeguards listed above, in conjunction with other remedies discussed below.

2. Establishing an Independent Transmission Monitor.

Section F.2 of the Complaint proposes that "FERC should develop an Independent Transmission Monitor ("ITM") that would review all local projects in Ohio." Industrial Customers generally agree that an independent entity should be reviewing and approving all transmission projects, or at least all transmission projects at 100 kV and above. Given the staggering increase in transmission spending and the proliferation of Supplemental Projects that undergo little, if any, independent review, a clarification or expansion of the existing independent market monitor ("IMM") functions, or the creation of a new ITM function, would be a timely and appropriate exercise of the Commission's authority to remedy unjust, unreasonable, unduly discriminatory, or preferential transmission rates.

Establishing independent oversight of transmission planning and, in particular, Supplemental Project development, would not cause the Commission to run afoul of sub-delegation prohibitions as long as the ITM's roles and responsibilities are properly defined. The Commission addressed identical concerns with respect to the creation of IMMs in Order 2000 where it emphasized that "the performance of market monitoring … is not intended to supplant Commission authority" but would instead provide FERC with additional means to detect market power abuses, market design flaws and opportunities for improvements in market efficiency.[92] FERC has ultimate authority to deny cost recovery for projects that do not comply with the necessary review/approval processes. Having PJM review and approve Supplemental Projects, with IMM or ITM oversight, also protects all states in the PJM market and levels the playing field between states in the region to keep the market efficient, effective, and fair in the allocation of ratepayer resources that market participants expend towards supplemental projects.

This is not the first time the Commission has considered the value of an ITM. In RM05-17-000 and RM05-25-000, which would ultimately culminate in the issuance of Order No. 890, numerous parties proposed, and the Commission considered, whether to appoint an independent entity to monitor transmission processes. The Commission noted that "overall comments on the use of an independent third party to oversee or coordinate the planning process range from those who believe it is not needed to those who feel it should be required rather than merely encouraged."[93] The ITM would monitor compliance with the rules for competitive transmission

[92] Order 2000 at 465.

[93] Order No. 890 at P 563.

processes, make suggestions for process improvements, and report any rules violations directly to the FERC Office of Enforcement.

The Commission has broad discretion in determining the scope of the ITM functions. At the very narrow end of a spectrum of authorized duties, the ITM would monitor for compliance with existing legally enforceable obligations of PJM and jurisdictional transmission owners and refer to the Commission any perceived tariff violations. For example, the ITM would monitor compliance with transmission planning process requirements. Because competition is deployed in PJM, the ITM would monitor for, and report, non-compliance with Commission-approved processes and anti-competitive conduct. At the broad end of the spectrum of functionality, an ITM may participate in any of the following areas:

1. Monitoring the transmission planning processes for optimization opportunities with respect to cost containment and competition;
2. Reporting on barriers to deploying competition for new transmission facilities above 100 kV;
3. Developing and evaluating benchmark estimates of costs using data collected over time;
4. Upon request, testifying or providing information to state siting and integrated resource plan ("IRP")-issuing authorities to assist with need and cost determinations;
5. Participating in proceedings before the Commission, as necessary, to address transmission competition administration issues; and
6. Participating in formula rate and stated rate cost recovery proceedings before the Commission.

The scope of ITM responsibilities may further be reviewed, on a periodic basis, where legal, structural, or PJM market circumstances warrant such review. To carry out its responsibilities with respect to monitoring, reporting, and advising on transmission issues, the ITM should have access to all transmission planning and cost data, including critical energy infrastructure information ("CEII"). With respect to the ITM structure, the Commission may consider enhancing the functions of the existing external Independent Market Monitor in PJM by expanding its areas of responsibilities and funding to allow for the necessary increases in technical and personnel capacity.

A PJM ITM "would be able to identify valuable recommendations for improvements in the modeling, project identification, and . . . planning processes and inconsistencies with other processes including the generation interconnection process."[94] Further, as noted by Monitoring Analytics, the information provided by an ITM would be essential for the Commission, for state public utility commissions, for all PJM market participants, for all customers in PJM, and for PJM Staff.[95]

In conclusion, having an ITM in the PJM Region (through the existing IMM or otherwise) would result in projects facing more scrutiny, and will mitigate the rate impacts on consumers of Supplemental Projects. In addition, PJM could and should serve as the reviewer and approver of Supplemental Projects. PJM is already separate from the utilities and has substantial expertise in regional transmission planning. By having these reviewing and approving functions, PJM can provide a more holistic grid planning process that includes supplemental projects as an option for reasonable and prudent grid expansion because current transmission planning is short-sighted and does not co-optimize the benefits of economic and reliability objectives. A longer planning and benefits horizon will reduce the susceptibility of transmission planning to shifts in short-term assumptions, such as the near-term generation plans of incumbent utilities that stifle efficient regional transmission development to justify rate basing generation assets at much higher cost to consumers. And the process for transmission monitoring can be overseen by the Independent

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[94] Potomac Economics Comments filed Oct. 12, 2021, in Docket No. RM21-17-000 at 9.

[95] Monitoring Analytics Comments filed Oct. 12, 2021, in Docket No. RM21-17-000 at 17.

Market Monitor to ensure that the ITM functions properly. Such responsibility can be seamlessly integrated into the oversight responsibilities of current Independent Market Monitor in PJM.

3. Using Stated Transmission Rates to Recover Project Costs.

Section F.3 of the Complaint proposes that "FERC also should consider requiring the Ohio Transmission Utilities to use only a stated-rate approach to determining transmission rates in Ohio." The Industrial Customers agree with this proposal for Ohio, and for other states in the PJM Region. The Commission's rate recovery processes should vary according to the level of independent oversight in the selection and approval of transmission facilities. While independent review and approval, and independent transmission monitoring, are lacking, the Commission should not allow transmission owners to rely on formula rate processes that lack essential prerequisites to allow meaningful stakeholder participation, cost examination, and challenges.

However, formula rate recovery may continue to be appropriate for regional transmission projects that undergo an independent board review and approval process and are subject to independent monitoring. In such circumstances, however, the transmission owner should have, and maintain, the burden of demonstrating that all costs for which it is seeking pass-through in a formula rate were prudently incurred and are otherwise just and reasonable. The current process of formula transmission rates and formula transmission rate protocols, while allowing for informational requests to be submitted to the transmission owner, does not provide the rigor or the discipline necessary to ensure that all investment is prudent. Lack of adequate independent oversight in the development of projects, and lack of effective oversight in the cost recovery process, will increase the implementation of suboptimal Supplemental Projects that can lead to higher costs and less access to the transmission system. Therefore, in the absence of a rigorous independent review of transmission project costs, it is appropriate to return to the fundamental principle that has guided cost of service ratemaking for decades and allow full discovery and cross-examination on expenditures, while placing the burden of proof on the party seeking cost recovery, through the use of stated transmission rates implemented in an evidentiary hearing context.

4. Preconstruction Review for Supplemental Projects.

The Complaint's final proposal is for FERC to "develop a remedy that is just, reasonable, not unduly discriminatory and not unduly preferential for a pre-construction review of the need, prudence and cost efficiency of local transmission projects developed by Ohio Transmission Utilities," should FERC reject all of the other proposals. The Industrial Customers recommend that, in lieu of committing FERC to review each and every supplemental project to determine if the investment is prudent, FERC and customers would be better-served by the Industrial Customers' Recommendation below.

B. Industrial Customers' Recommended Remedy.

The Commission should adopt a bright-line 100 kV threshold for transmission monitoring and regional planning to ensure consumers receive the full benefits of transmission development at just and reasonable rates. A voltage threshold of 100 kV would provide a bright-line, non-subjective criterion for determining transmission projects that must be regionally planned. The Commission, as well as the North American Electric Reliability Corporation ("NERC"), have historically recognized that power lines 100 kV and above are considered transmission facilities and are part of the bulk electric system.[96] By requiring regional planning for all projects 100 kV and above, the cost of local and smaller projects would decrease, resulting in more capital available for the types of regional projects that the Commission appears to have a desire to support. Importantly, this threshold and requirement would not impose upon state jurisdiction any additional oversight for local projects, but would only ensure that regional planning, needs and

[96] Revision to the Electric Reliability Organization Definition of Bulk Electric System, Order No. 743, 133 FERC ¶ 61,150 at P 30 (2010).

cost-effectiveness reviews, and competition for regional projects are administered by PJM. As the Pennsylvania Public Utility Commission ("PaPUC") has noted, "projects built by incumbent transmission owners [Supplemental Projects] are demonstrably more expensive in almost every case. By mile and by peak load served, over the last decade, PJM baseline projects, which are mostly subject to competition, are less expensive than transmission owner-driven local 'supplemental' projects."[97] Regional planning and competition for all projects is necessary to ensure that rates can be just and reasonable.

[97] PaPUC Comments in Docket No. RM21-17-000, at 22, citing 2021 PJM Regional Transmission Expansion Plan at 294-295, https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx (accessed Sept. 14, 2022).

IV. CONCLUSION

There is no meaningful check on transmission owners' spending on Supplemental Projects. Prudence challenges are not viable and very rarely succeed; formula rate transmission protocols suffer from serious inadequacies that cause them to fail to protect consumers; the Attachment M-3 process does not provide real opportunities for a meaningful review and engagement that would discipline in any way the level of transmission owners' spend on Supplemental Projects; and state levels of review during the Certificate of Convenience and Public Necessity application process are, in most of the states in the PJM Region, not adequate to enable a meaningful review of both the need and the cost-effectiveness of Supplemental Projects. These inherent process deficiencies cause transmission rates to be unjust and unreasonable. The Commission has multiple options for crafting a just and reasonable replacement rate. Industrial Customers strongly recommend a requirement of regional planning for all transmission projects 100 kV and above. That solution, combined with real opportunities for discovery and cross-examination that only stated rate cases can provide, would cure the process deficiencies that cause current rates to be unjust and reasonable.

Respectfully submitted,

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Dated: November 17, 2023

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via first-class mail, electronic transmission, or hand-delivery, the foregoing upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Robert A. Weishaar, Jr.
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Dated: November 17, 2023

EXHIBITS

Exhibit A: AEP’s Formula Rate Protocols, H-14A

ATTACHMENT H-14A
THE AEP EAST OPERATING COMPANIES
FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP East Companies" or "AEP") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEP shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-14B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEP's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1.<u>**Annual Projection**</u>

a.No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEP shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. AEP shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a publicly accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

b.The posting of the Annual Projection shall:

(i)Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;

(ii)Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties[1] to replicate the calculation of the projected Net Revenue Requirement;

(iii)With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)

A.Identify any Accounting Changes including:

i.The initial implementation of an accounting standard or policy;

ii.The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii.Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;

iv.The implementation of new estimation methods or policies that change prior estimates; and

v.Changes to income tax elections;

B.Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

C.Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and

D.Provide, for each item identified pursuant to Section 1.b.iii.A - C of these Protocols, a narrative explanation of the individual impact of such changes on the projected Net Revenue Requirement.

(iv)Include the following information related to affiliate cost allocation:

A.A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and

B.The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.

c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.[2] Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

d.Together with the posting of the Annual Projection, AEP shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEP will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e.To the extent AEP agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.

f.The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEP will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEP's projected Net Revenue Requirement collected during the previous Rate Year[3] will be compared to AEP's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEP's Formula Rate and based upon (i) AEP's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEP's calculation of its annual revenue requirement, (iii) the books and records of AEP (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates,[4] to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").

b.Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. Annual Update

a.On or before May 25 following each Rate Year, AEP shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.

b.If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c.The date on which the posting occurs shall be that year's "Annual Update Publication Date."

d.Together with the posting of the Annual Update, AEP shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEP will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e.The Annual Update posting for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[5]

(ii)Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual Update results from the FERC Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii)Shall identify:

A.Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:

i.The initial implementation of an accounting standard or policy;

ii.The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv.The implementation of new estimation methods or policies that change prior estimates; and

v.Changes to income tax elections;

B.Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);

C.Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

D.For each item identified pursuant to Sections 3.e.iii.A – C of these Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v)Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi)Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).

f.The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for P ostretirement Benefits Other Than Pensions.

g.**Example – Timelines for 2018 Annual Projection and 2019 Annual Update**:

On or before October 31, 2017, AEP will determine the projected Net Revenue Requirement for the 2018 Rate Year. AEP will post the Annual Projection for the 2018 Rate Year in accordance with Section 1 above. On or before May 25, 2019, AEP will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. <u>Annual Review Procedures</u>

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a.Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEP or by FERC order) ("Review Period"), to review the calculations and to notify AEP in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEP shall cause to be posted all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.

b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

c.AEP shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party.

d.AEP shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.

e.Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEP or by FERC order) to serve reasonable information requests on AEP ("Discovery Period").

f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.

g.AEP shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEP shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEP will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEP's response(s) to such requests, and a link to the website will be e-mailed to the PJM Exploder

List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party. Voluminous materials will be made available at a physical AEP site.

h. AEP shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEP's Annual Update or Annual Projection.

i.To the extent AEP and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

j.Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.

k.If a change made by AEP to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5.Resolution of Challenges

a.Interested Parties shall have up to two-hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEP or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEP informational filing and shall be served on AEP by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEP pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.

b.Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:

(i)Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;

(ii) Explain how the action or inaction violates the filed rate Template or Protocols;

(iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including

A. The extent or effect of an Accounting Change;

B.Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

C.The proper application of the Template and procedures in these Protocols;

D.The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;

E.The prudence of actual costs and expenditures;

F.The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

G.Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.

(iv)Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi)State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii)Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii)State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

c.Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

e.Any response by AEP to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.

f.In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEP shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it <u>has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable</u> <u>requirements and procedures in applying the Formula Rate</u>. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

g.Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEP to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.

h.AEP may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for P ostretirement Benefits Other Than Pensions. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEP any burden with respect to such other aspects of the Formula Rate.

Section 6.<u>Changes to Annual Updates</u>

If AEP determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its

FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

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[1] As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

[2] For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

[3] If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

[4] *PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.*

[5] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

Exhibit B: AEP's Ohio Transmission Company, H-20A

ATTACHMENT H-20 A

THE AEP TRANSMISSION COMPANIES IN THE AEP ZONE FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc. (collectively "AEPTCo") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEPTCo shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-20B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEPTCo's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1. <u>Annual Projection</u>

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEPTCo shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. AEPTCo shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a publicly accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

b. The posting of the Annual Projection shall:

   (i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;

(ii) Include all inputs in sufficient detail to identify the components of AEPTCo's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties[1] to replicate the calculation of the projected Net Revenue Requirement;

(iii) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)

A. Identify any Accounting Changes including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and

v. Changes to income tax elections;

B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and

D. Provide, for each item identified pursuant to Section 1.b.iii.A - C of these Protocols, a narrative explanation of the individual impact of such changes on the projected Net Revenue Requirement.

(iv) Include the following information related to affiliate cost allocation:

A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and

B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.

c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.[2] Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

d. Together with the posting of the Annual Projection, AEPTCo shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEPTCo will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. To the extent AEPTCo agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.

f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEPTCo will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEPTCo's projected Net Revenue Requirement collected during the previous Rate Year[3] will be compared to AEPTCo's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEPTCo's Formula Rate and based upon (i) AEPTCo's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEPTCo's calculation of its annual revenue requirement, (iii) the books and records of AEPTCo (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates,[4] to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").

b .Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credtited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. <u>Annual Update</u>

a. On or before May 25 following each Rate Year, AEPTCo shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the posting occurs shall be that year's "Annual Update Publication Date."

d. Together with the posting of the Annual Update, AEPTCo shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEPTCo will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. The Annual Update posting for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[5]

(ii) Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual Update results from the FERC Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii) Shall identify:

A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and

v. Changes to income tax elections;

B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

D. For each item identified pursuant to Sections 3.e.iii.A – C of these Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting f or Postretirement Benefits Other Than Pensions.

g. **Example – Timelines for 2018 Annual Projection and 2019 Annual Update**:

On or before October 31, 2017, AEPTCo will determine the projected Net Revenue Requirement for the 2018 Rate Year. AEPTCo will post the Annual Projection for the 2018 Rate Year in accordance with Section 1 above. On or before May 25, 2019, AEPTCo will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. <u>Annual Review Procedures</u>

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEPTCo or by FERC order) ("Review Period"), to review the calculations and to notify AEPTCo in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEPTCo shall cause to be posted all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.

b. In the event of a Preliminary Challenge, AEPTCo will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

c. AEPTCo shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEPTCo agrees or disagrees with the challenge. If AEPTCo disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEPTCo shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEPTCo and the requesting party.

d. AEPTCo shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.

e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order) to serve reasonable information requests on AEPTCo ("Discovery Period").

f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEPTCo Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.

g. AEPTCo shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEPTCo shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEPTCo will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEPTCo's response(s) to such requests, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEPTCo and the requesting party. Voluminous materials will be made available at a physical AEP site.

h. AEPTCo shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEPTCo's Annual Update or Annual Projection.

i. To the extent AEPTCo and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEPTCo or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.

k. If a change made by AEPTCo to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. <u>Resolution of Challenges</u>

a. Interested Parties shall have up to two –hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEPTCo informational filing and shall be served on AEPTCo by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEPTCo pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.

b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:

(i) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;

(ii) Explain how the action or inaction violates the filed rate Template or Protocols;

(iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including

A. The extent or effect of an Accounting Change;

B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

C. The proper application of the Template and procedures in these Protocols;

D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;

E. The prudence of actual costs and expenditures;

F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.

(iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v) S tate whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

e. Any response by AEPTCo to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.

f. In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEPTCo shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in applying the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEPTCo to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.

h. AEPTCo may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting f or Postretirement Benefits Other Than Pensions. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEPTCo any burden with respect to such other aspects of the Formula Rate.

Section 6. <u>Changes to Annual Updates</u>

If AEPTCo determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

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[1] *As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.*

[2] For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

[3] If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The

first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

[4] PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.

[5] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

Exhibit C: ATSI Formula Rate Protocols, H-21

ATTACHMENT H-21
Annual Transmission Rates -- American Transmission Systems, Incorporated for Network Integration Transmission Service

1. The transmission revenue requirement and the rate for Network Integration Transmission Service are equal to the results of the formula shown in Attachment H-21A, and will be posted on the PJM website pursuant to Attachment H-21B (Formula Rate Protocols). The transmission revenue requirement and the rate reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of American Transmission Systems, Incorporated ("ATSI"). Service utilizing other ATSI facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate set forth in Attachment H-21A shall be calculated on the basis of projections, subject to true-up to actual data in accordance with the adjustment mechanism described in Attachment H-21B (Formula Rate Protocols).

3. Within the ATSI Zone, a Network Customer's peak load shall be adjusted to include transmission loss percentages for 69 kV and above facilities applied to the measured load, as well as any distribution losses as reflected in applicable state tariffs and/or service agreements that contain specific distribution loss factors for the Network Customer. The transmission loss percentage for load served utilizing 138 kV and above facilities shall be 1.486 percent, and the transmission loss percentage for load served utilizing both 138 kV and above transmission facilities and 69 kV transmission facilities shall be 2.786 percent.

4. The rate and revenue requirement in this attachment shall be effective until amended by ATSI or modified by the Commission.

5. In addition to the rate set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse ATSI for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6. Network Customers within the ATSI Zone shall be credited for recovery of costs associated with Regional Transmission Expansion Plan ("RTEP") projects under the formula rate provided in Attachment H-21A.

7. *[RESERVED]*

Exhibit D: Attachment M-3

ATTACHMENT
M-3
ADDITIONAL PROCEDURES FOR PLANNING
SUPPLEMENTAL PROJECTS AND ASSET MANAGEMENT PROJECTS

(a) Applicability. Each Transmission Owner shall be responsible for planning and constructing in accordance with Schedule 6 of the Operating Agreement as provided in this Attachment M-3, to the extent applicable, (i) Asset Management Projects, as defined herein, (ii) Supplemental Projects, as defined in section 1.42A.02 of the Operating Agreement, and (iii) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM to address one or more of the following planning criteria:

1. NERC Reliability Standards (which includes Applicable Regional Entity reliability standards);

2. Individual Transmission Owner planning criteria as filed in FERC Form No. 715 and posted on the PJM website, provided that the Additional Procedures for the Identification and Planning of EOL Needs, set forth in section (d), shall apply, as applicable;

3. Criteria to address economic constraints in accordance with section 1.5.7 of the Operating Agreement or an agreement listed in Schedule 12-Appendix B;

4. State Agreement Approach expansions or enhancements in accordance with section 1.5.9(a)(ii) of the Operating Agreement; or

5. An expansion or enhancement to be addressed by the RTEP Planning Process pursuant to section (d)(2) of this Attachment M-3 in accordance with RTEP Planning Process procedures in Schedule 6 of the Operating Agreement.

This Attachment M-3 shall not apply to CIP-014 mitigation projects that are subject to Attachment M-4.

(b) Definitions.

1. Asset Management Project. "Asset Management Project" shall mean any modification or replacement of a Transmission Owner's Transmission Facilities that results in no more than an Incidental Increase in transmission capacity undertaken to perform maintenance, repair, and replacement work, to address an EOL Need, or to effect infrastructure security, system reliability, and automation projects the Transmission Owner undertakes to maintain its existing electric transmission system and meet regulatory compliance requirements.

2. Attachment M-3 Project. "Attachment M-3 Project" means (i) an Asset Management Project that affects the connectivity of Transmission Facilities that are included in the Transmission System, affects Transmission Facility ratings or significantly changes the impedance of Transmission Facilities; (ii) a Supplemental Project; or (iii) any other expansion or enhancement of Transmission Facilities that is not excluded from this Attachment M-3 under any of clauses (1) through (5) of section (a). "Attachment M-3

Project" does not include a project to address Form No. 715 EOL Planning Criteria. 3. Incidental Increase. "Incidental Increase" shall mean an increase in transmission capacity achieved by advancements in technology and/or replacements consistent with current Transmission Owner design standards, industry standards, codes, laws or regulations, which is not reasonably severable from an Asset Management Project. A transmission project that results in more than an Incidental Increase in transmission capacity is an expansion or enhancement of Transmission Facilities.

4. Transmission Facilities. "Transmission Facilities" shall have the meaning set forth in the Consolidated Transmission Owners Agreement, section 1.27.

5. EOL Need. "EOL Need" shall mean a need to replace a transmission line between breakers operating at or above 100 kV or a transformer, the high side of which operates at or above 100 kV and the low side of which is not connected to distribution facilities, which the Transmission Owner has determined to be near the end of its useful life, the replacement of which would be an Attachment M-3 Project.

6. Candidate EOL Needs List. "Candidate EOL Needs List" shall have the meaning ascribed to it in section (d)(1)(iii).

7. Form No. 715 EOL Planning Criteria. "Form No. 715 EOL Planning Criteria" shall mean planning criteria filed by a Transmission Owner in FERC Form No. 715 to address EOL Needs. No Transmission Owner may be compelled to file a Form No. 715 EOL Planning Criteria not required to be filed pursuant to FERC regulations applicable to Form No. 715.

8. Attachment M-3 EOL Planning Criteria. "Attachment M-3 EOL Planning Criteria" shall mean planning criteria utilized by a Transmission Owner under Attachment M-3 to address EOL Needs.

9. PJM Planning Criteria Need. "PJM Planning Criteria Need" shall mean a need to plan a transmission expansion or enhancement of Transmission Facilities other than those reserved to each Transmission Owner in accordance with section (a).

10. RTEP Planning Process. "RTEP Planning Process" shall mean the process by which PJM develops the Regional Transmission Expansion Plan under Schedule 6 of the Operating Agreement.

(c) Procedures for Review of Attachment M-3 Projects. The following procedures shall be applicable to the planning of Attachment M-3 Projects:

1. **Review of Attachment M-3 Projects.** As described in sections 1.3(c) and (d) of Schedule 6 of the Operating Agreement, the Subregional RTEP Committees shall be responsible for the review of Attachment M-3 Projects. The Subregional RTEP Committees shall have a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for Attachment M-3 Projects. Disputes shall be resolved in accordance with the procedures set forth at Schedule 5 of the Operating Agreement. For purposes of this section (c),

reference to the Subregional RTEP Committees shall be deemed to include the Transmission Expansion Advisory Committee (TEAC) when the TEAC reviews Attachment M-3 Projects in accordance with these procedures.

2. **Review of Assumptions and Methodology.** In accordance with sections 1.3(d), 1.5.4(a), and 1.5.6(b) and 1.5.6(c) of Schedule 6 of the Operating Agreement, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions, and models Transmission Owners propose to use to plan and identify Attachment M-3 Projects (Assumptions Meeting). Each Transmission Owner shall provide the criteria, assumptions, and models to PJM for posting at least 20 days in advance of the Assumptions Meeting to provide Subregional RTEP Committee Participants sufficient time to review this information. Stakeholders may provide comments on the criteria, assumptions, and models to the Transmission Owner for consideration either prior to or following the Assumptions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Assumptions Meeting and may respond or provide feedback as appropriate.

3. **Review of System Needs.** No fewer than 25 days after the Assumptions Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review the identified criteria violations and resulting system needs, if any, that may drive the need for an Attachment M-3 Project (Needs Meeting). Each Transmission Owner will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and models that it uses to plan Attachment M-3 Projects. The Transmission Owners shall share and post their identified criteria violations and drivers no fewer than 10 days in advance of the Needs Meeting. Stakeholders may provide comments on the criteria violations and drivers to the Transmission Owner for consideration prior to, at, or following the Needs Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Needs Meeting and may respond or provide feedback as appropriate.

4. **Review of Potential Solutions.** No fewer than 25 days after the Needs Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review potential solutions for the identified criteria violations (Solutions Meeting). The Transmission Owners shall share and post their potential solutions, as well as any alternatives identified by the Transmission Owners or stakeholders, no fewer than 10 days in advance of the Solutions Meeting. Stakeholders may provide comments on the potential solutions to the Transmission Owner for consideration either prior to or following the Solutions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the meeting and may respond or provide feedback as appropriate.

5. **Submission of Attachment M-3 Projects.** Each Transmission Owner will finalize for submittal to the Transmission Provider Attachment M-3 Projects for inclusion in the Local Plan in accordance with section 1.3 of Schedule 6 of the Operating Agreement and the schedule established by the Transmission Provider. Stakeholders may provide

comments on the Attachment M-3 Projects in accordance with section 1.3 of Schedule 6 of the PJM Operating Agreement before the Local Plan is integrated into the Regional Transmission Expansion Plan. Stakeholders shall have at least 10 days to comment on the Local Plan after the solutions selected by the Transmission Owner for inclusion in the Local Plan are posted. Each Transmission Owner shall review and consider comments that are received at least 10 days before the Local Plan is submitted for integration into the Regional Transmission Expansion Plan.

6. **Information Relating to Attachment M-3 Projects.** Information relating to each Transmission Owner's Attachment M-3 Projects will be provided in accordance with, and subject to the limitations set forth in, section 1.5.4 of Schedule 6 of the Operating Agreement. Local Plan Information will be provided to and posted by the Office of Interconnection as set forth in section 1.5.4(e) of Schedule 6 of the Operating Agreement.

7. **No Limitation on Additional Meetings and Communications or Use of Attachment M-3 For Other Transmission Projects.**

   i. Nothing in this Attachment M-3 precludes any Transmission Owner from agreeing with stakeholders to additional meetings or other communications regarding Attachment M-3 Projects, in addition to the Subregional RTEP Committee process.

   ii. Nothing in this Attachment M-3 precludes a Transmission Owner from using the procedures set forth in section (c) to solicit stakeholder input in the planning of Transmission Facilities not subject to this section (c) or the RTEP Planning Process.

(d) Additional Procedures for the Identification and Planning of EOL Needs.

1. **EOL Need Planning Criteria Documentation and Identification**

   i. Each PJM Transmission Owner shall develop documentation for its Attachment M-3 EOL Planning Criteria and/or its Form 715 EOL Planning Criteria through which each identifies EOL Needs.

   ii. Each Transmission Owner's Attachment M-3 EOL Planning Criteria and/or Form 715 EOL Planning Criteria shall be clearly and separately delineated and presented by the Transmission Owner at least once annually pursuant to section (c)(2) and/or in its FERC Form No. 715 at a meeting of the TEAC.

   iii. Annually, each Transmission Owner will provide to PJM a Candidate EOL Needs List comprising its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs documented under section (d)(1)(i). Each Transmission Owner may change its projection as it deems necessary and will update it annually. Any Candidate EOL Needs List provided to PJM shall remain confidential within PJM, except to the extent necessary for PJM to make the determination referenced in clause (a) of section (d)(2)(ii).

2. **Coordination of EOL Needs Planning With PJM Planning Criteria Needs**.

i. If, as part of the RTEP Planning Process, PJM initially determines that a substantial electrical overlap exists such that a single Solution may address a validated PJM Planning Criteria Need(s) identified during the current PJM planning cycle under the RTEP Planning Process and address a projected EOL Need on the Candidate EOL Needs List, which the relevant Transmission Owner has confirmed remains a projected EOL Need, the relevant Transmission Owner shall consult with PJM regarding such potential overlap.

ii. If, (a) PJM determines through the RTEP Planning Process that a proposed Required Transmission Enhancement would more efficiently and cost-effectively address the identified PJM Planning Criteria Need and may, as well, address the projected EOL Need confirmed under section (d)(2)(i), and (b) the proposed Required Transmission Enhancement is not a solution proposed by the Transmission Owner pursuant to section (c)(4), and (c) the Transmission Owner determines that the projected EOL Need is not met by the proposed Required Transmission Enhancement and determines that it will plan an Attachment M-3 Project to address the projected EOL Need or propose a project to address the Form No. 715 EOL Planning Criteria, the Transmission Owner will provide documentation to PJM and stakeholders on the rationale supporting its determination at the next appropriate meeting of the TEAC or Subregional RTEP Committee that considered the proposed Required Transmission Enhancement.

(e) Modifications. This Attachment M-3 may only be modified under section 205 of the Federal Power Act if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with section 8.5 of the Consolidated Transmission Owners Agreement.

Exhibit E: APS Supplemental Projects Completed

Subregional RTEP Committee – Western
FirstEnergy Supplemental Projects

April 21, 2023

Needs

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

APS Transmission Zone M-3 Process
Stoner Junction 138 kV Line

Need Number: APS-2023-006

Process Stage: Need Meeting 04/21/2023

Project Driver: *Equipment Material Condition, Performance and Risk*

Specific Assumption Reference:

Line Condition Rebuild/Replacement

- Age/condition of wood pole transmission line structures
- System characteristics including lightning and grounding performance, galloping overlap, insulation coordination, structural capacity needs, clearance margins, and future needs (e.g., fiber path)

System Performance Projects Global Factors

- Substation/line equipment limits

Problem Statement:

The Connellsville – Iron Bridge – King Farm (Stoner Junction) 138 kV line is exhibiting deterioration and has significant outage history

- Approximately 15 miles of this line is on wood structures nearing end of life. They are recommended for rebuild.
- 78% of structures (89 of 114) did not meet one or more assessment criteria.
- The 4.3-mile balance of line is on lattice towers where 15 of 21 had correctable defects.
- The original conductor is 336.4 26/7 ACSR with original and maintenance splices and should be considered for replacement.
- There are 31 recent maintenance conditions, primarily due to wood pole conditions or rusted hardware. Conditions are expected to deteriorate as equipment approaches end of life.

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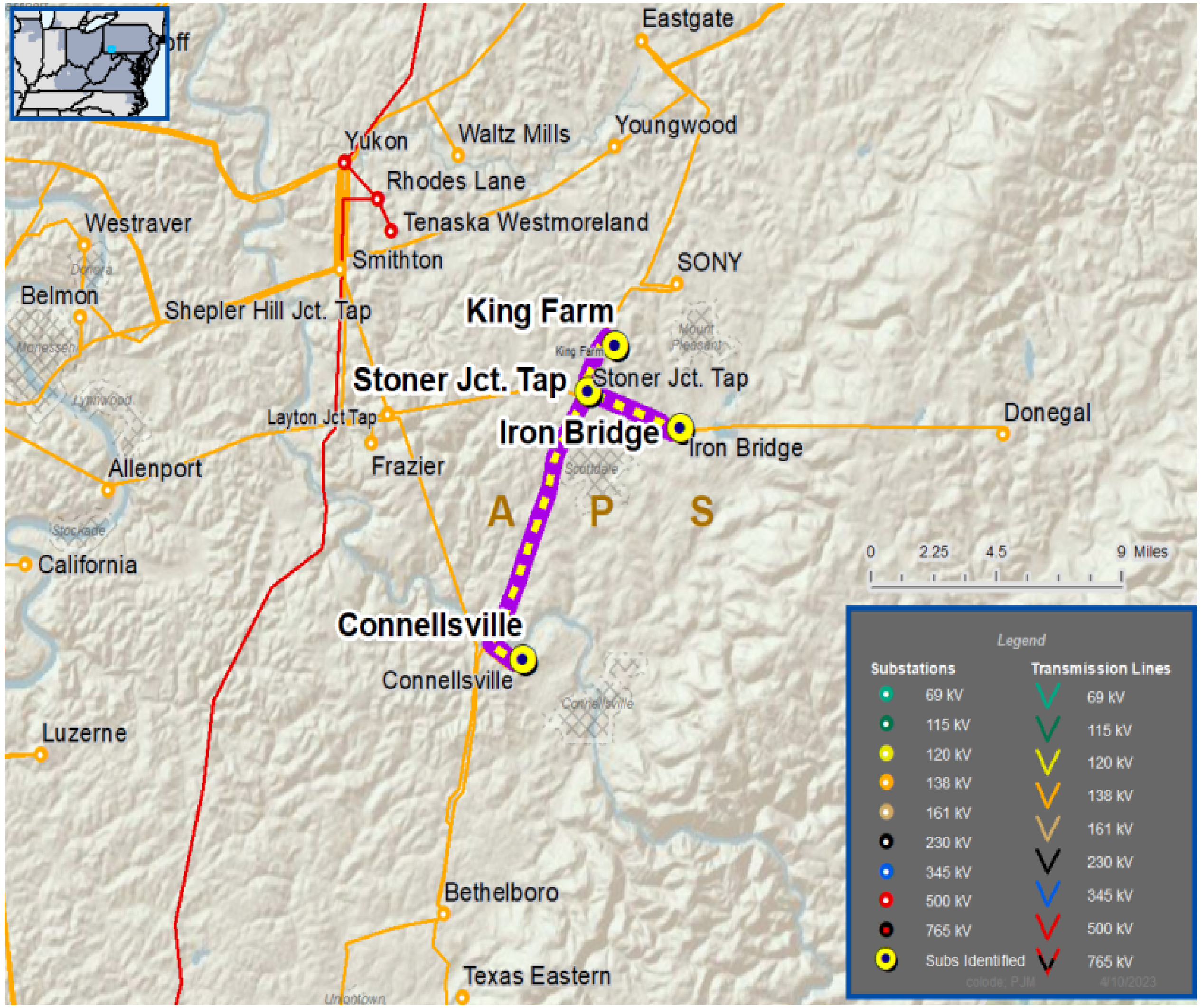

APS Transmission Zones M-3 Process
Stoner Junction 138 kV Misoperation Relays

Need Numbers: APS-2023-011

Process State: Need Meeting 04/21/2023

Project Driver: *Equipment Material Condition, Performance and Risk*

Specific Assumption Reference:

System Performance Projects Global Factors
- System reliability and performance
- Substation/line equipment limits

System Condition Projects
- Substation Condition Rebuild/Replacement

Upgrade Relay Schemes
- Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
- Communication technology upgrades

Problem Statement:
- FirstEnergy has identified protection schemes using a certain vintage of relays and communication equipment that have a history of misoperation.
- Proper operation of the protection scheme requires all the separate components perform adequately during a fault.
- In many cases the protection equipment cannot be repaired due to a lack of replacement parts and available expertise in the outdated technology.
- Transmission line ratings are limited by terminal equipment.

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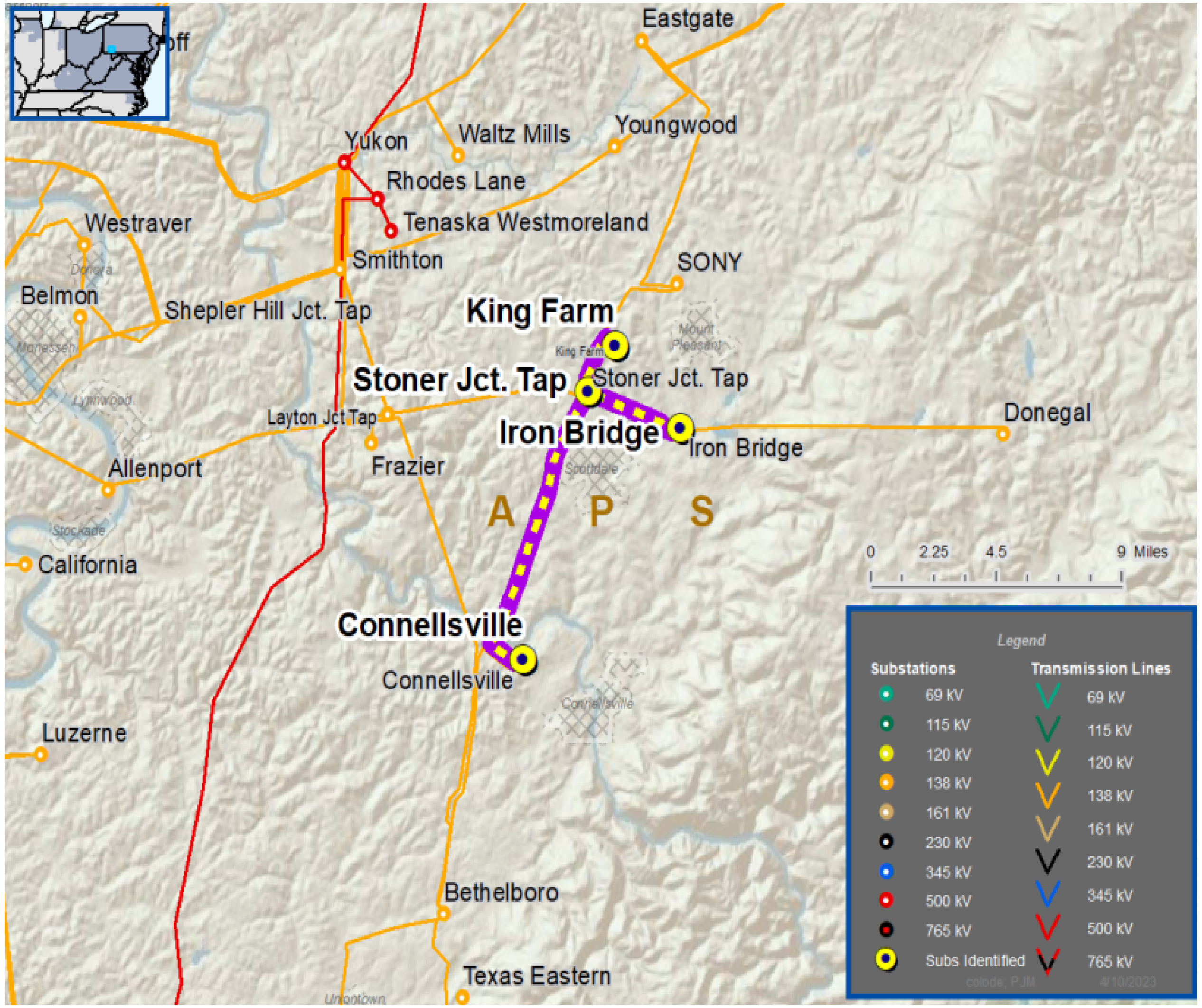


Need #	Transmission Line / Substation Locations	Existing Line Rating (SN / SE)	Existing Conductor Rating (SN / SE)	Limiting Terminal Equipment
APS-2023-006 APS-2023-011	Connellsville – Stoner Junction 138 kV	160 / 192	308 / 376	Substation Conductor, Wave Trap, Relaying
	Stoner Junction – King Farm 138 kV	293 / 343	308 / 376	Substation Conductor, Circuit Breaker, Wave Trap, Relaying
	Stoner Junction – Iron Bridge 138 kV	210 / 250	221 / 268	Substation Conductor, Circuit Breaker, Wave Trap, Relaying

Need Number: APS-2023-007

Process Stage: Need Meeting – 4/21/2023

Project Driver(s): *Customer Service*

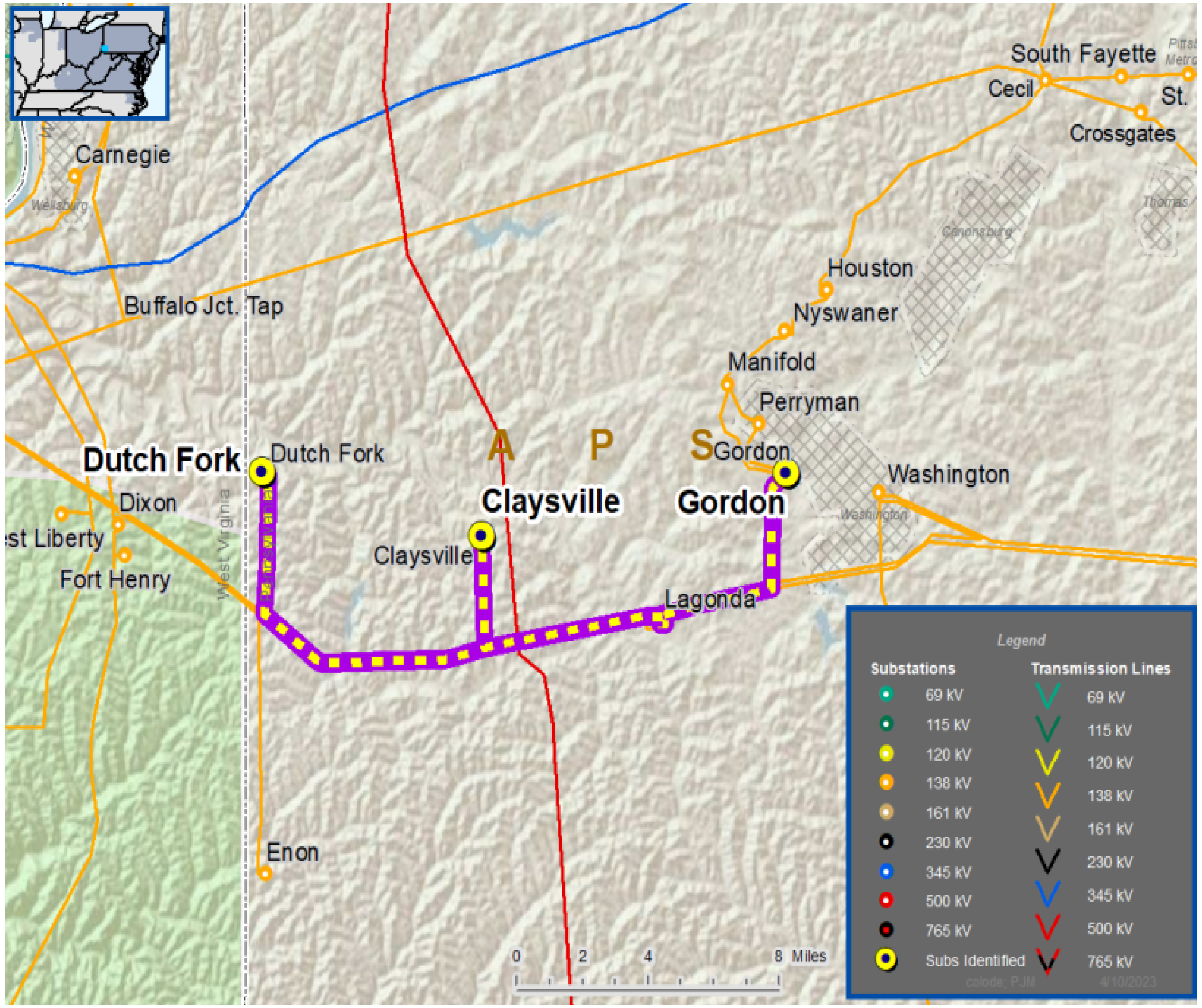
Specific Assumption Reference(s):

New customer connection request will be evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement:

New Customer Connection - has requested a new 138 kV delivery point near the Claysville-Washington 138 kV line. The anticipated load of the new customer connection is 25 MVA.

Requested in-service date is 07/10/2024.



Need Number: APS-2023-008

Process Stage: Need Meeting – 4/21/2023

Project Driver(s):

Customer Service

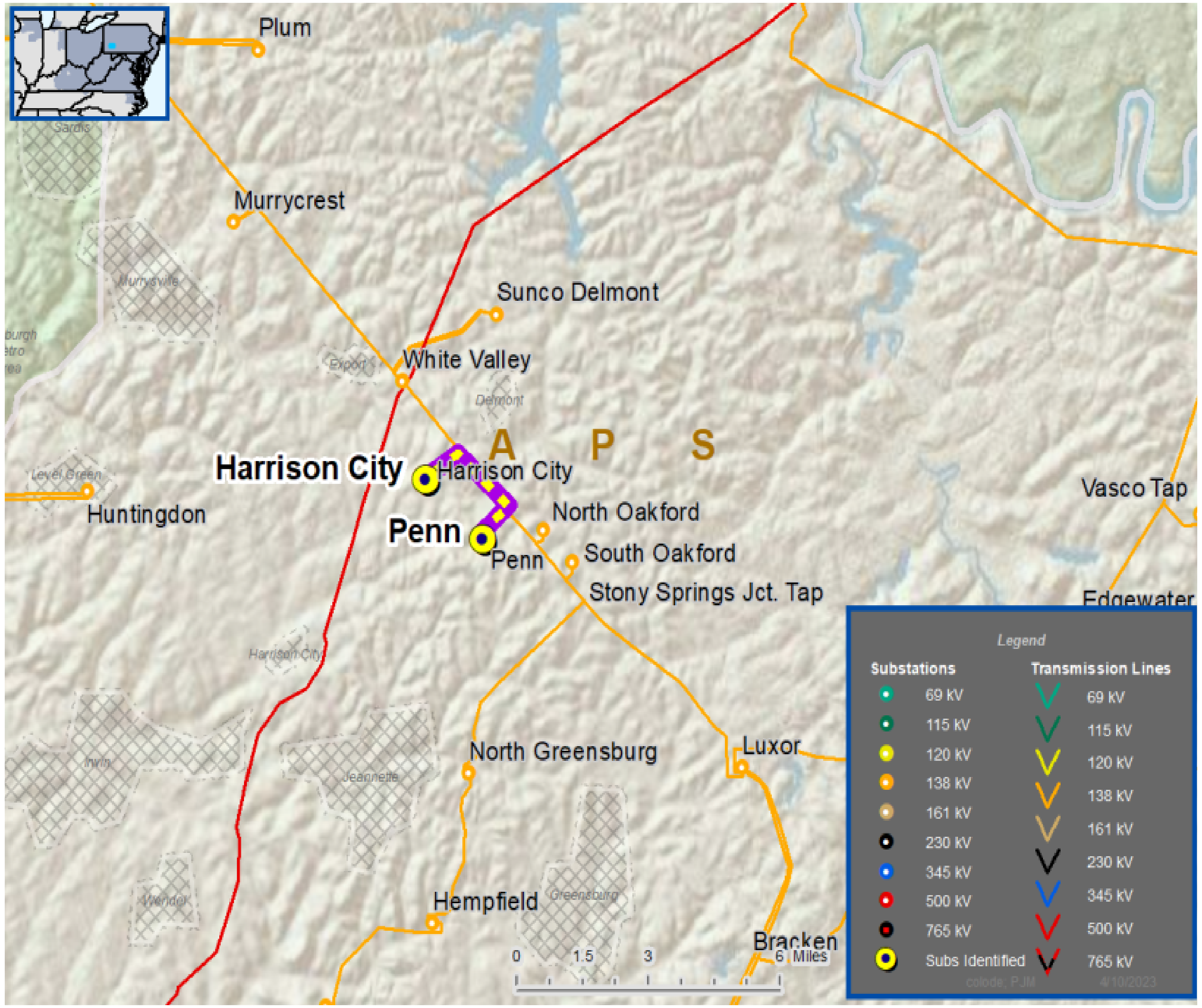
Specific Assumption Reference(s):

New customer connection request will be evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement:

New Customer Connection - has requested a new 138 kV delivery point near the Penn-Harrison City 138 kV line. The anticipated load of the new customer connection is 100 MVA.

Requested in-service date is 12/31/2024.



FirstEnergy

APS Transmission Zone M-3 Process
Ethel Springs – Bethlen 138 kV Network

Need Number: APS-2023-009

Process Stage: Need Meeting – 4/21/2023

Project Driver(s):

- *Equipment material condition, performance and risk*
- *Operational Flexibility and Efficiency*

Specific Assumption Reference(s):

System Performance

- Network radial lines

Operational Flexibility

Problem Statement:

The are two radial feeds: one to Bethlen and one to Ethel Spring.

A fault on the Loyalhanna - Social Hall 138 kV line will outage multiple 138 kV stations, which puts significant stress on the networked distribution system.

A fault on the Loyalhanna - Social Hall 138 kV line will outage radial load at Ethel Springs, and a fault on the Bethlen – Loyalhanna 138 kV line will outage radial load at Bethlen. Ethel Springs serves 6,105 customers and 14.43 MW, and Bethlen serves 5,110 customers and 11.76 MW.

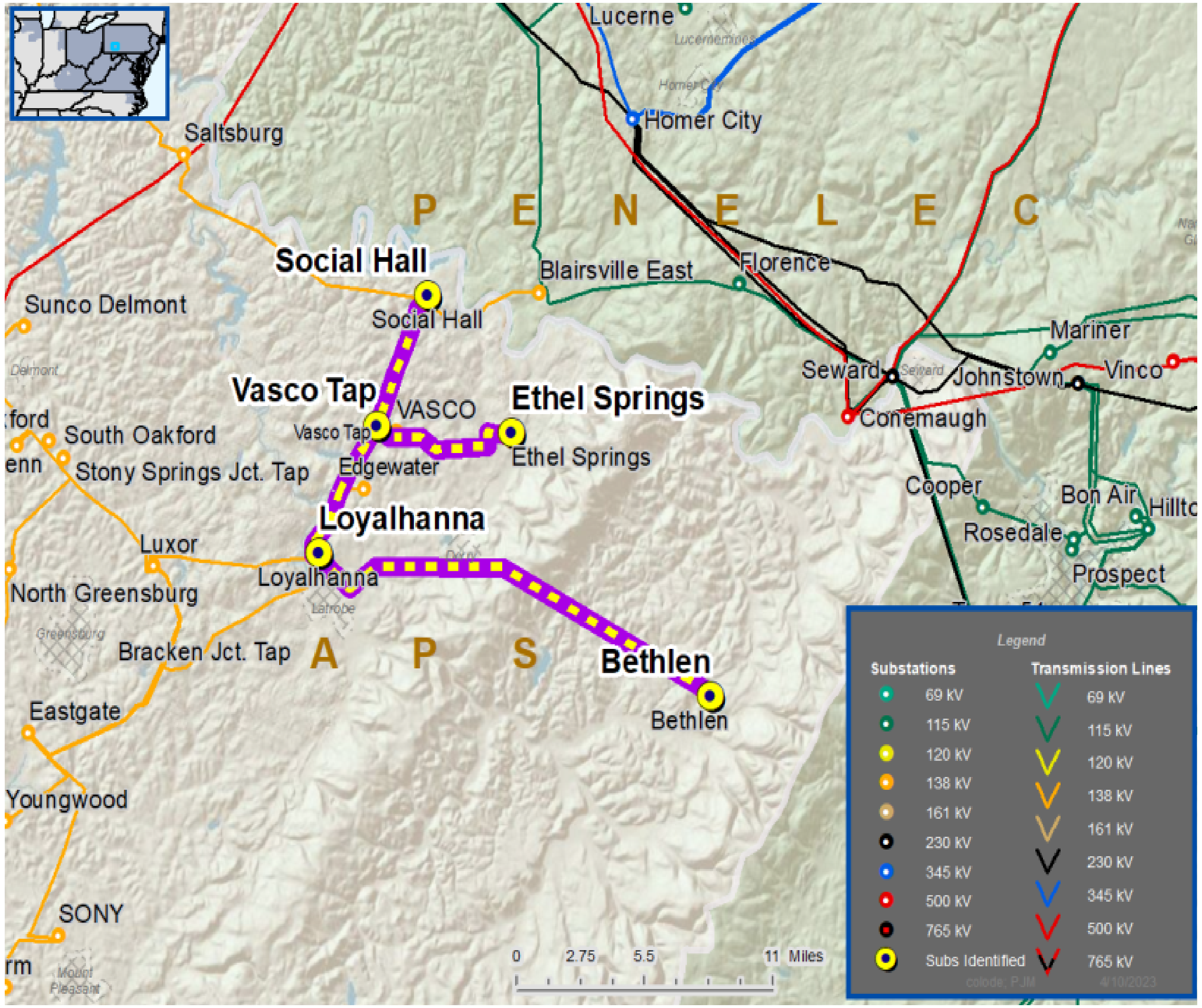
Transmission line ratings are limited by terminal equipment.

Vasco Tap – Social Hall 138 kV (Substation conductor, wave trap, CB, relaying):

- Existing line rating: 225 / 287 MVA (SN / SE)
- Existing conductor rating: 308 / 376 MVA (SN / SE)

Bethlen – Loyalhanna 138 kV (Substation conductor, relaying):

- Existing line rating: 205 / 242 MVA (SN / SE)
- Existing conductor rating: 309 / 376 MVA (SN / SE)



Guilford – Grand Point 138: Upgrade limiting terminal equipment

Need Number: APS-2023-010
Process Stage: Need Meeting – 4/21/2023

Project Driver(s):
- *Performance and risk*
- *Operational Flexibility and Efficiency*

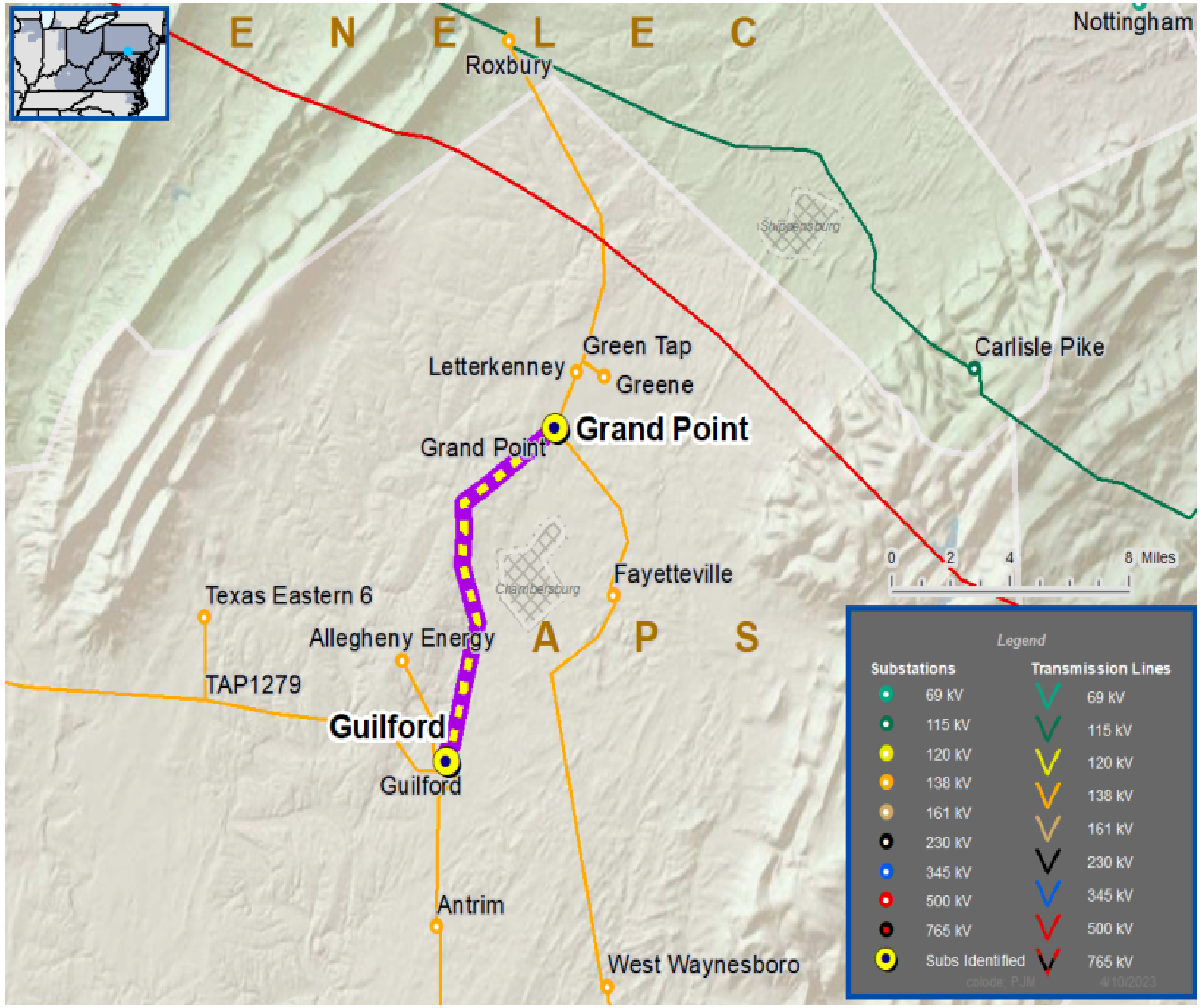
Specific Assumption Reference(s)
- System reliability and performance
- Substation/line equipment limits

Problem Statement

A new customer connection causes a thermal violation on the Guilford – Grandpoint 138 kV line.

Transmission line ratings are limited by terminal equipment.

Guilford – Grand Point 138 kV (Substation conductor, wave trap):
- Existing line rating: 195 / 209 MVA (SN / SE)
- Existing conductor rating: 221 / 268 MVA (SN / SE)



Need Number: APS-2023-012

Process Stage: Need Meeting 04/21/2023

Project Driver: *Equipment Material Condition, Performance and Risk*

Specific Assumption Reference:

Substation Condition Rebuild/Replacement

- Age/condition of structural components and their associated foundations

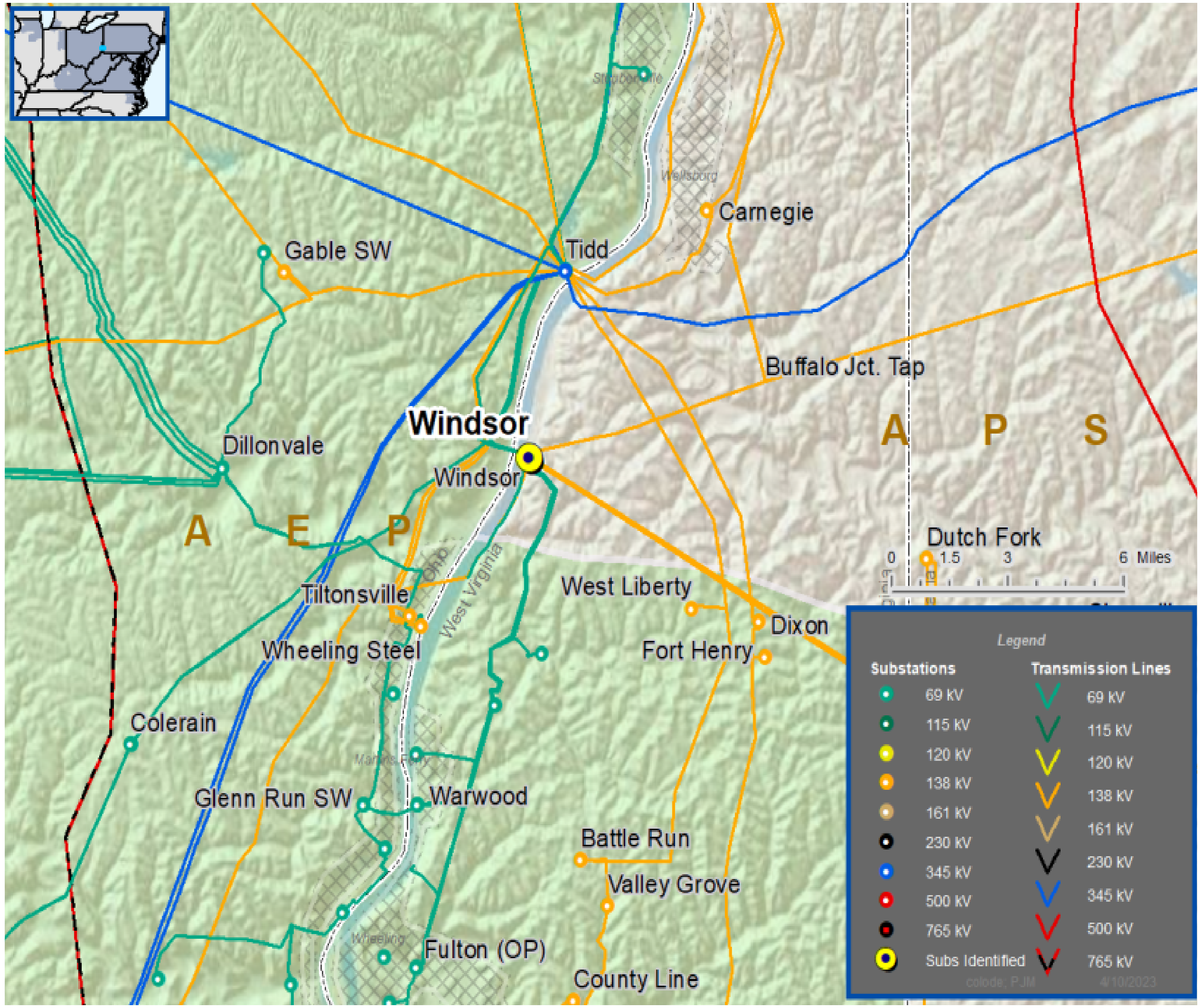
System Performance Projects Global Factors

- Substation/line equipment limits

Problem Statement:

The Windsor Substation in West Virginia is exhibiting significant deterioration and soil erosion.

- Windsor Substation was constructed in 1915.
- A condition assessment has shown eroded soil, deteriorated ground grid, crumbling structure foundations, and steel structure deterioration.
- Windsor Substation has four networked 138 kV lines, two networked 25 kV lines, and one 138/25 kV transformer.



Solution

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

FirstEnergy

APS Transmission Zone M-3 Process
Misoperation Relay Project

Need Number: APS-2021-007
Process State: Solution Meeting 04/21/2023
Previously Presented: Need Meeting 08/16/2021

Project Driver:
Equipment Material Condition, Performance and Risk

Specific Assumption Reference:
Global Factors

- System reliability and performance
- Substation and line equipment limits
- Upgrade Relay Schemes
  - Relay schemes that have a history of misoperation
  - Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
  - Communication technology upgrades
  - Bus protection schemes

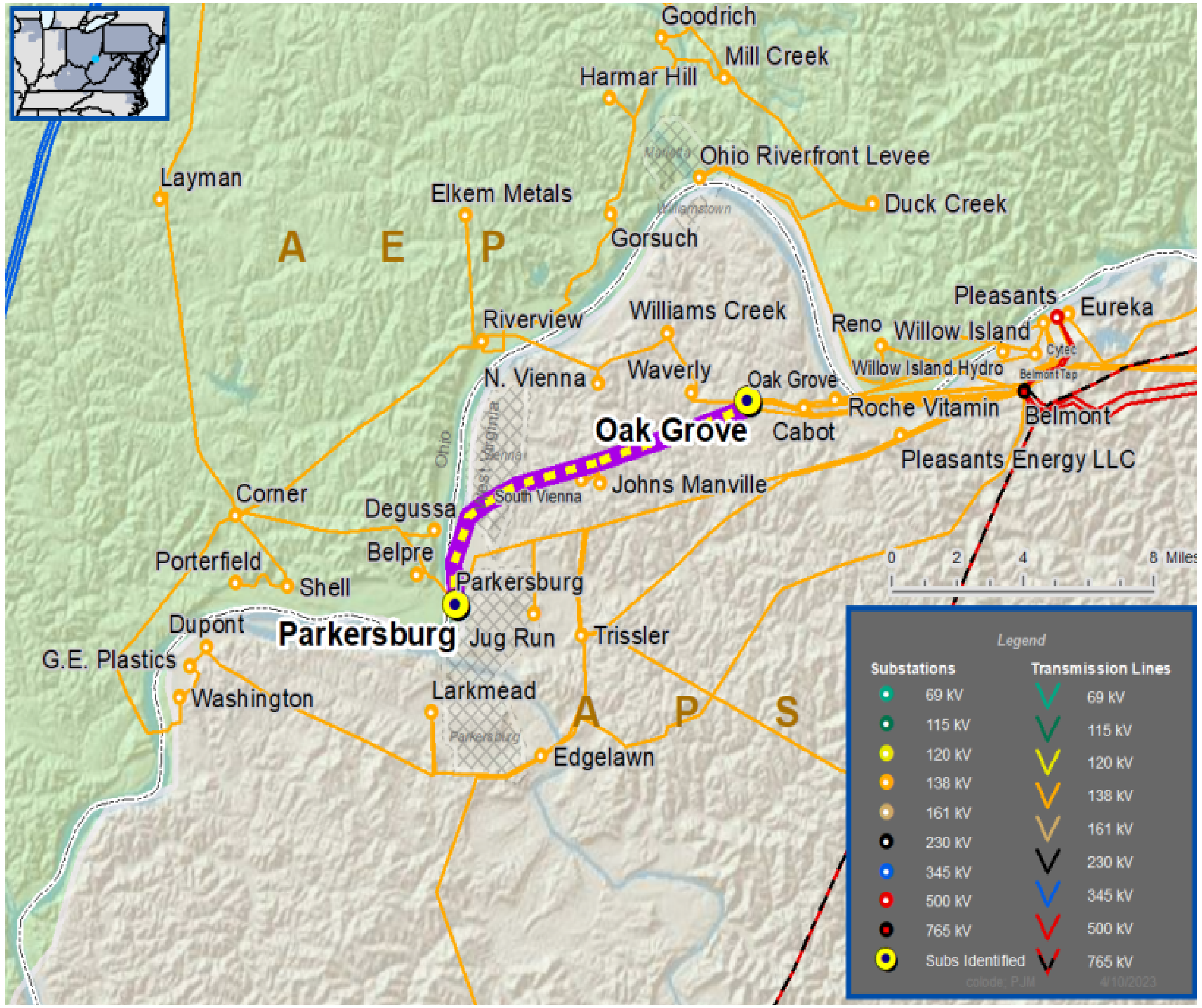
Problem Statement:

- FirstEnergy has identified protection schemes using a certain vintage of relays and communication equipment that have a history of misoperation.
- Proper operation of the protection scheme requires all the separate components perform properly together during a fault
- The identified protection equipment cannot be effectively repaired for reasons such as lack of replacement parts and available expertise in the outdated technology.
- Newer equipment provides better monitoring, enhances capability of system event analysis, and performs more reliably

- Transmission line ratings are limited by terminal equipment

Oak Grove – Parkersburg 638 138 kV Line (substation conductor)

- Existing line rating: 225 / 287 MVA (SN / SE)
- Existing Transmission conductor rating: 308 / 376 MVA (SN / SE)



Need Number: APS-2021-008
Process State: Solution Meeting 04/21/2023
Previously Presented: Need Meeting 08/16/2021

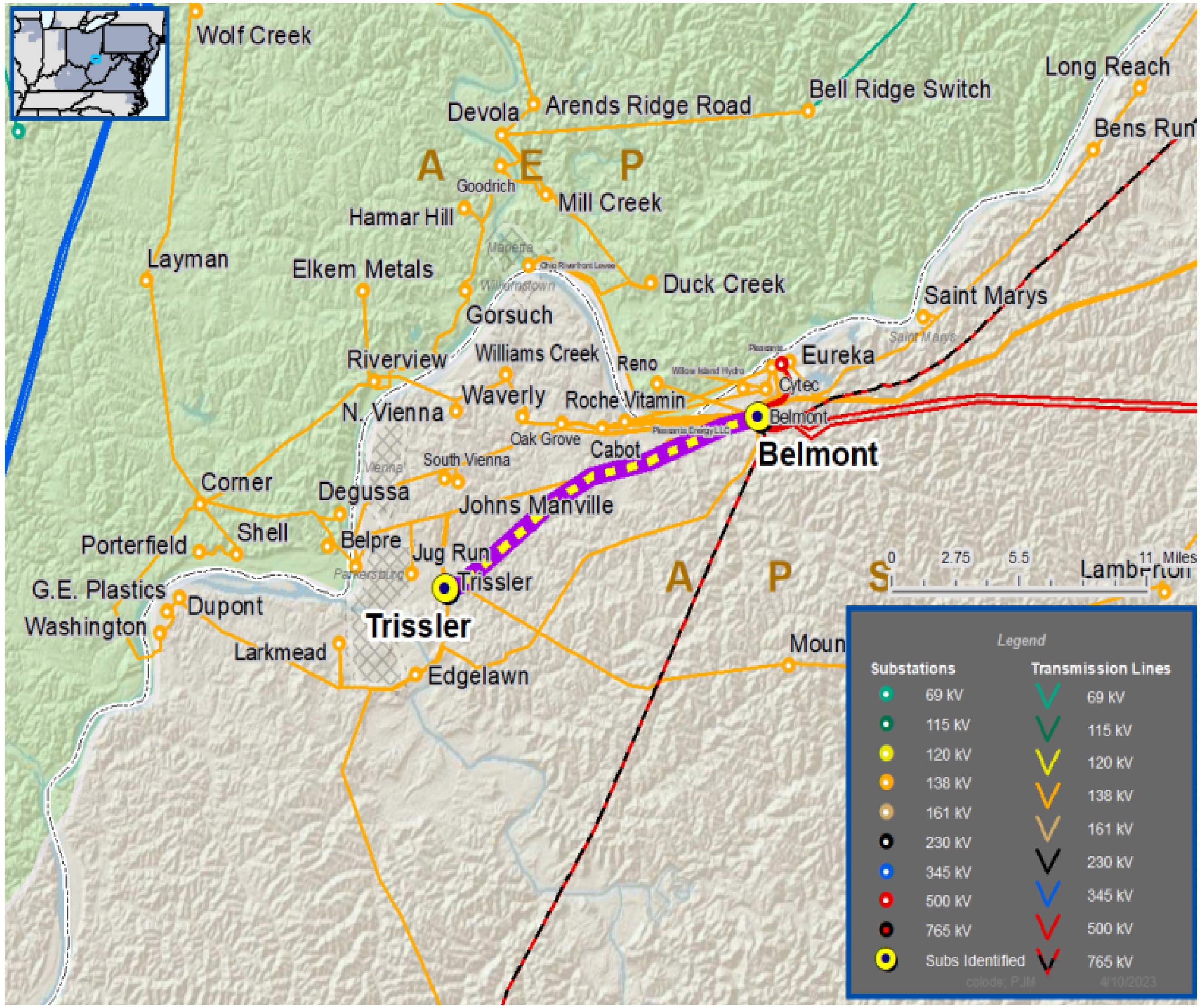
Project Driver:
Equipment Material Condition, Performance and Risk

Specific Assumption Reference:
Global Factors
- System reliability and performance
- Substation and line equipment limits
- Upgrade Relay Schemes
  - Relay schemes that have a history of misoperation
  - Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
  - Communication technology upgrades
  - Bus protection schemes

Problem Statement:
- FirstEnergy has identified protection schemes using a certain vintage of relays and communication equipment that have a history of misoperation.
- Proper operation of the protection scheme requires all the separate components perform properly together during a fault
- The identified protection equipment cannot be effectively repaired for reasons such as lack of replacement parts and available expertise in the outdated technology.
- Newer equipment provides better monitoring, enhances capability of system event analysis, and performs more reliably

- Transmission line ratings are limited by terminal equipment

Belmont – Trissler 648 138 kV Line (substation conductor)
- Existing line rating: 293 / 342 MVA (SN / SE)
- Existing Transmission conductor rating: 308 / 376 MVA (SN / SE)



APS Transmission Zone M-3 Process Misoperation Relay Project

Need Number: APS-2021-009
Process State: Solution Meeting 04/21/2023
Previously Presented: Need Meeting 08/16/2021

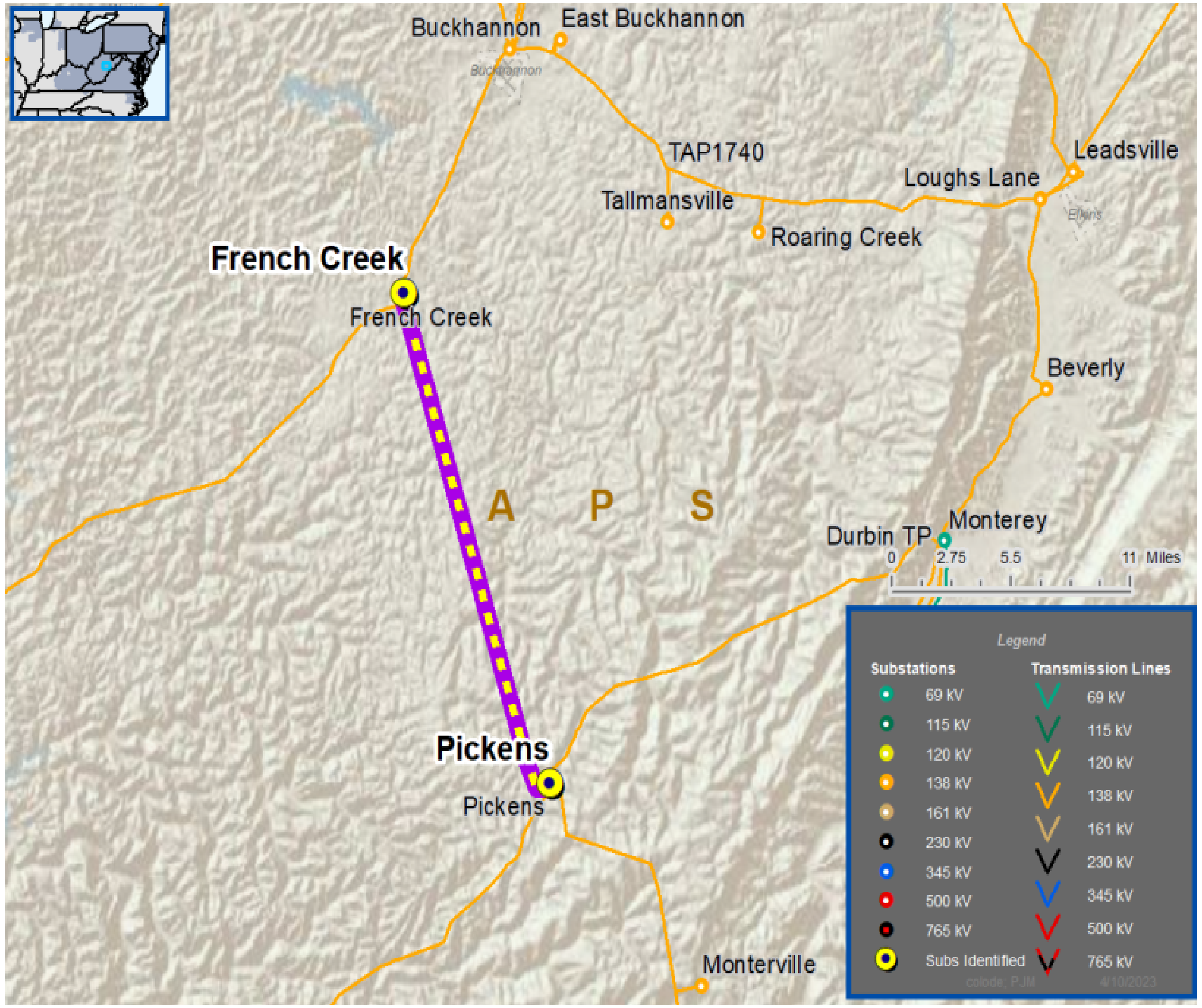
Project Driver:
Equipment Material Condition, Performance and Risk

Specific Assumption Reference:
Global Factors
- System reliability and performance
- Substation and line equipment limits
- Upgrade Relay Schemes
  - Relay schemes that have a history of misoperation
  - Obsolete and difficult to repair communication equipment (DTT, Blocking, etc.)
  - Communication technology upgrades
  - Bus protection schemes

Problem Statement:
- FirstEnergy has identified protection schemes using a certain vintage of relays and communication equipment that have a history of misoperation.
- Proper operation of the protection scheme requires all the separate components perform properly together during a fault
- The identified protection equipment cannot be effectively repaired for reasons such as lack of replacement parts and available expertise in the outdated technology.
- Newer equipment provides better monitoring, enhances capability of system event analysis, and performs more reliably

- Transmission line ratings are limited by terminal equipment

French Creek - Pickens 56 138 kV Line (substation conductor)
- Existing line rating: 292 / 306 MVA (SN / SE)
- Existing Transmission conductor rating: 308 / 376 MVA (SN / SE)



APS Transmission Zone M-3 Process Misoperation Relay Projects

Need Number	Transmission Line / Substation Locations	New MVA Line Rating (SN / SE)	Scope of Work	Estimated Cost ($ M)	Target ISD
APS-2021-007	Oak Grove – Johns Jct 138 kV Line	292 / 314	• Oak Grove 138 kV Substation – Replace substation conductor	$ 1.10 M	IN SERVICE
	Johns Jct – Parkersburg 138 kV Line	292 / 314	• Parkersburg 138 kV Substation – Replace substation conductor		
APS-2021-008	Belmont – Trissler 648 138 kV Line	308 / 376	• Belmont 138 kV Substation – Replace substation conductor and wave trap • Trissler 138 kV Substation – Replace substation conductor, circuit breaker, and wave trap	$ 2.08 M	IN SERVICE
APS-2021-009	French Creek – Pickens 138 kV Line	308 / 376	• French Creek 138 kV Substation – Replace substation conductor, circuit breaker, and wave trap • Pickens 138 kV Substation – Replace substation conductor, circuit breaker, and wave trap	$ 2.15 M	4/21/2023

Alternatives Considered: Maintain existing condition

Project Status: In construction

Model: 2022 RTEP model for 2027 Summer (50/50)

Need Number: APS-2023-003

Process Stage: Solution Meeting 4/21/2023

Previously Presented: Need Meeting 2/17/2023

Project Driver:

Customer Service

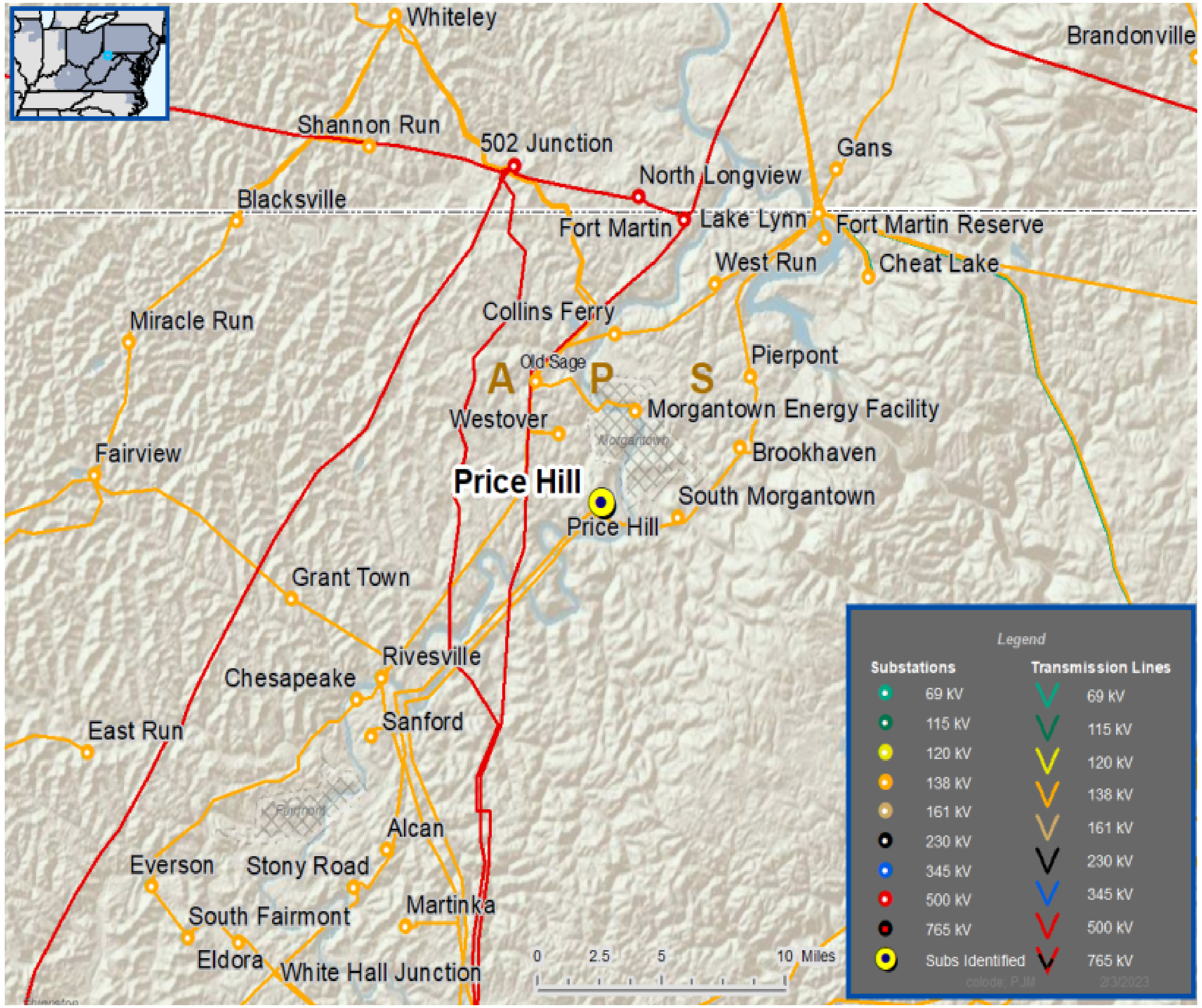
Specific Assumption Reference:

Customer request will be evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement:

New Customer Connection – A customer requested 138 kV service to support 8 MVA of load at a site near Price Hill 138 kV substation in the Mon Power service territory.

Requested in-service date is 3/17/2023



Need Number: APS-2023-003

Process Stage: Solution Meeting 4/21/2023

Proposed Solution:

- Extend the Price Hill 138 kV bus by installing (1) 138 kV breaker and associated facilities to provide service to the Customer.

Alternatives Considered:

- Serve the customer via the 12 kV distribution system

Anticipated Rating Changes:

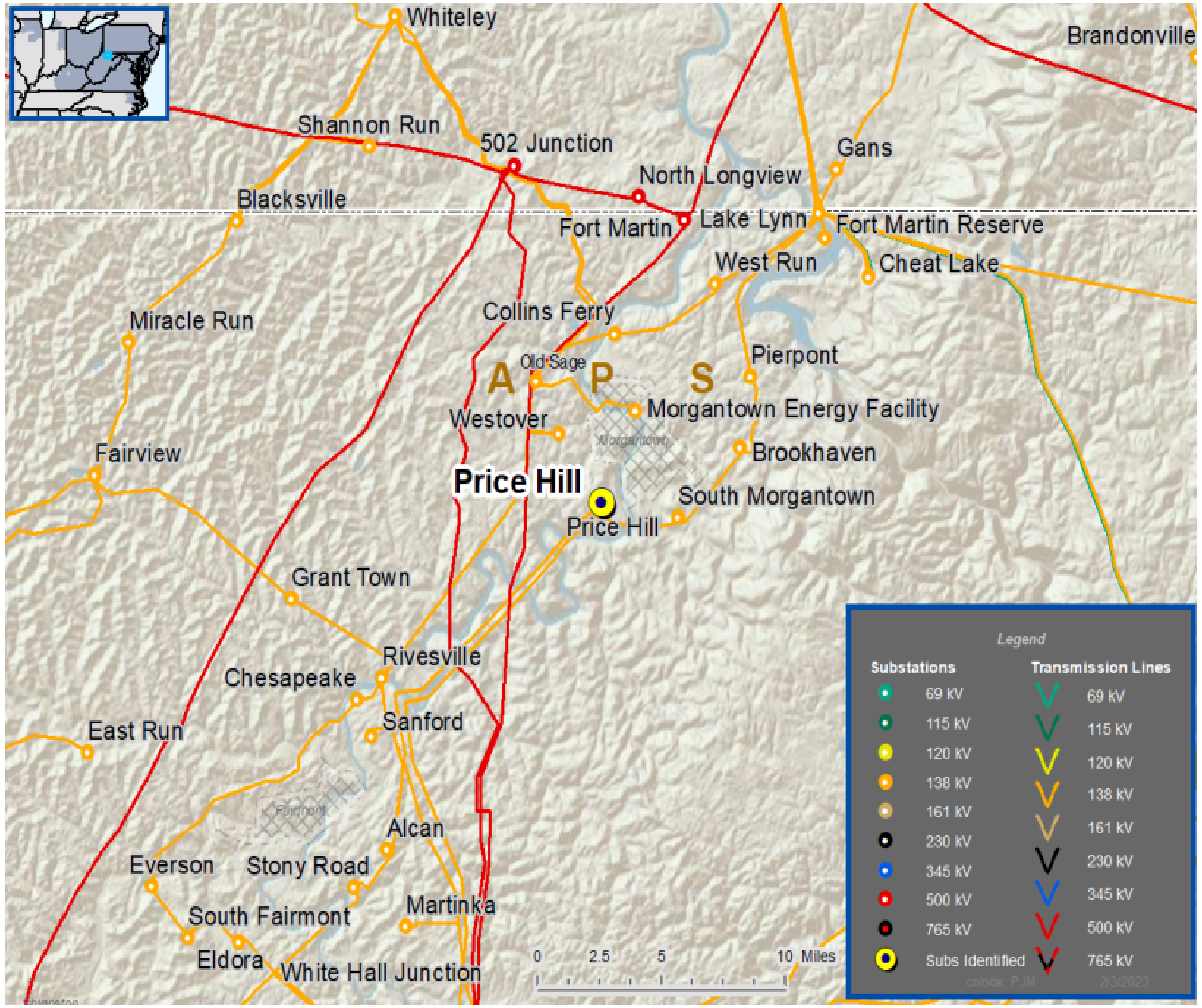
- None

Estimated Project Cost: $0.3M

Projected In-Service: 5/8/2023

Project Status: Under Construction

Model: 2022 RTEP model for 2027 Summer (50/50)



APS Transmission Zone M-3 Process

Need Number: APS-2023-004

Process Stage: Solution Meeting 04/21/2023

Previously Presented: Need Meeting 03/17/2023

Project Driver:

Equipment Material Condition, Performance and Risk

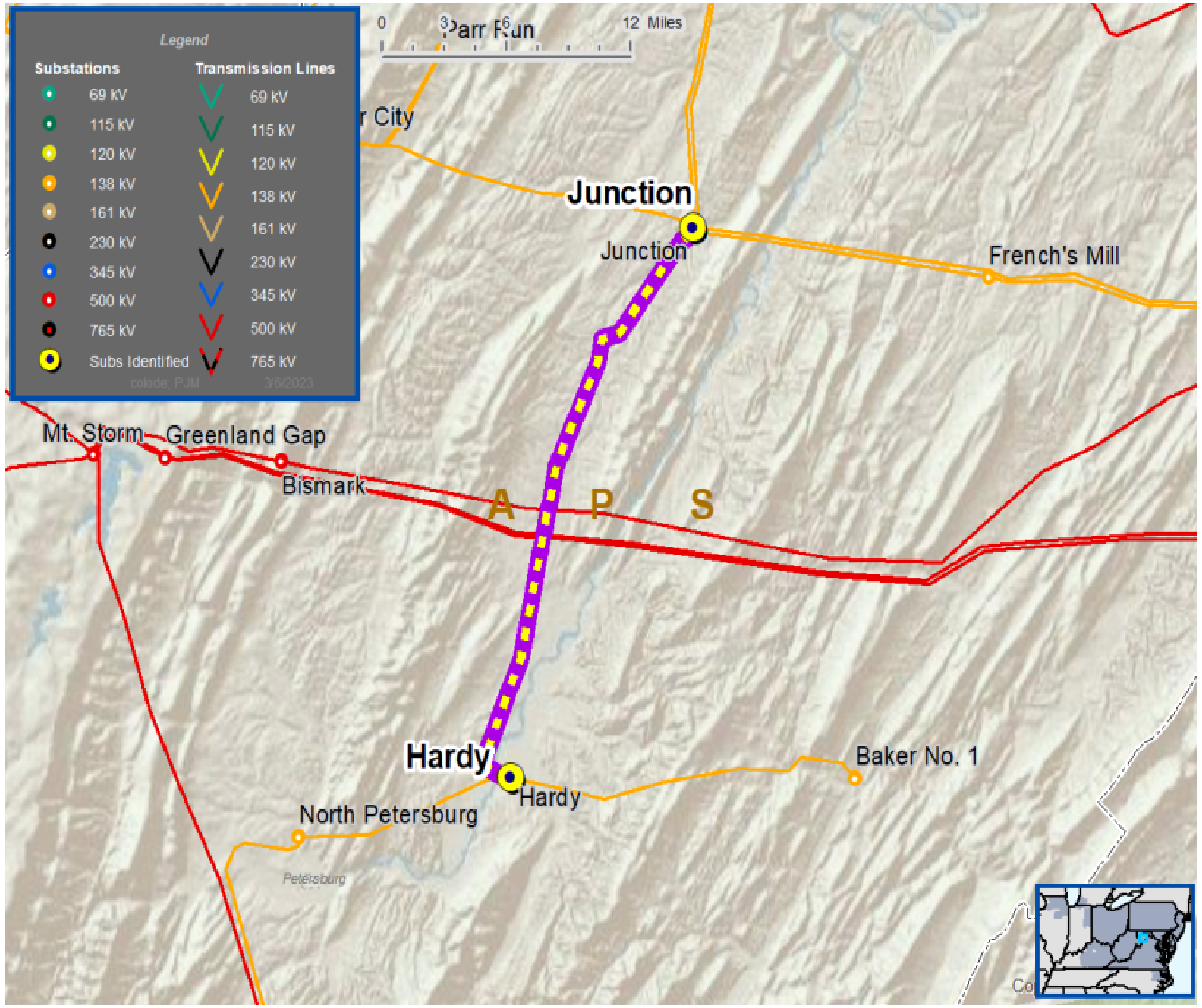
Specific Assumption Reference:

Line Condition Rebuild/Replacement
- Age/condition of wood pole transmission line structures
- System characteristics including lightning and grounding performance, galloping overlap, insulation coordination, structural capacity needs, clearance margins, and future needs (e.g., fiber path)

System Performance Projects Global Factors
- Substation/line equipment limits

Problem Statement:

The Hardy – Junction 138 kV line is exhibiting deterioration
- Total line distance is approximately 21.5 miles
- 157 of 164 structures failed assessment:
  - 145 structures are approaching expected end of life
  - 132 failed assessment due to multiple defects
  - 74 failed assessment due to decay
  - 132 failed assessment due to woodpecker holes



Need Number: APS-2023-004

Process Stage: Solution Meeting 04/21/2023

Proposed Solution:

- Rebuild the Junction-Hardy 138kV line, approximately 21.5 miles, with wood pole equivalent steel structures.
- Replace limiting substation conductor and disconnect switch at Junction 138 kV substation
- Replace limiting substation conductor at Hardy 138 kV substation

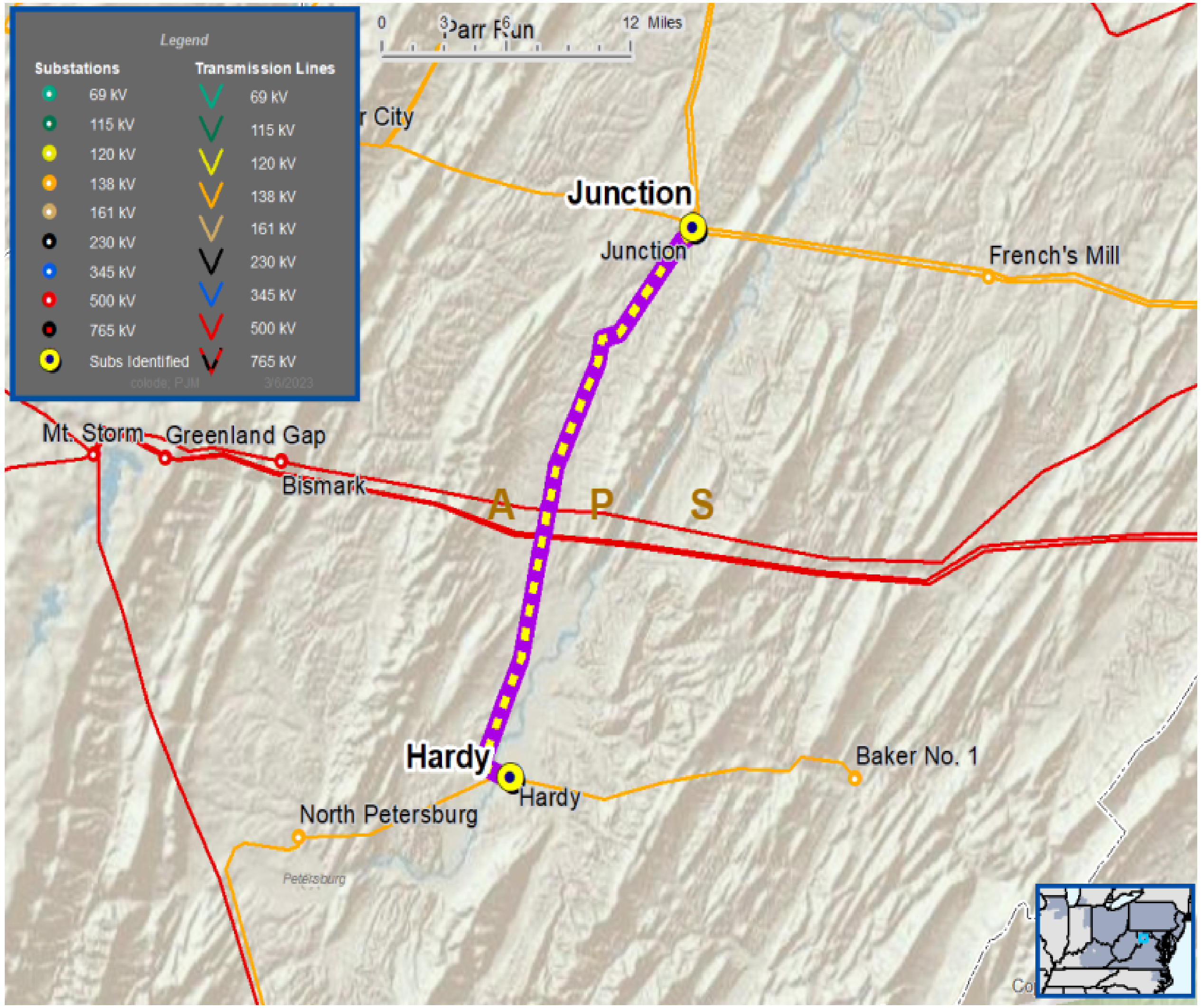
Transmission Line Ratings:

- Junction – Hardy 138 kV Line
  - Before Proposed Solution: 159 / 191 MVA (SN / SE)
  - After Proposed Solution: 221 / 268 MVA (SN / SE)

Alternatives Considered:

- Build a new greenfield line
- Maintain line in existing condition

Estimated Project Cost: $ 42.6 M
Projected In-Service: 12/1/2027
Project Status: Conceptual
Model: 2022 RTEP model for 2027 Summer (50/50)



Need Number: APS-2023-005

Process Stage: Solution Meeting 04/21/2023

Previously Presented: Need Meeting 03/17/2023

Project Driver:

Equipment Material Condition, Performance and Risk

Specific Assumption Reference:

Line Condition Rebuild/Replacement

- Age/condition of wood pole transmission line structures
- System characteristics including lightning and grounding performance, galloping overlap, insulation coordination, structural capacity needs, clearance margins, and future needs (e.g., fiber path)

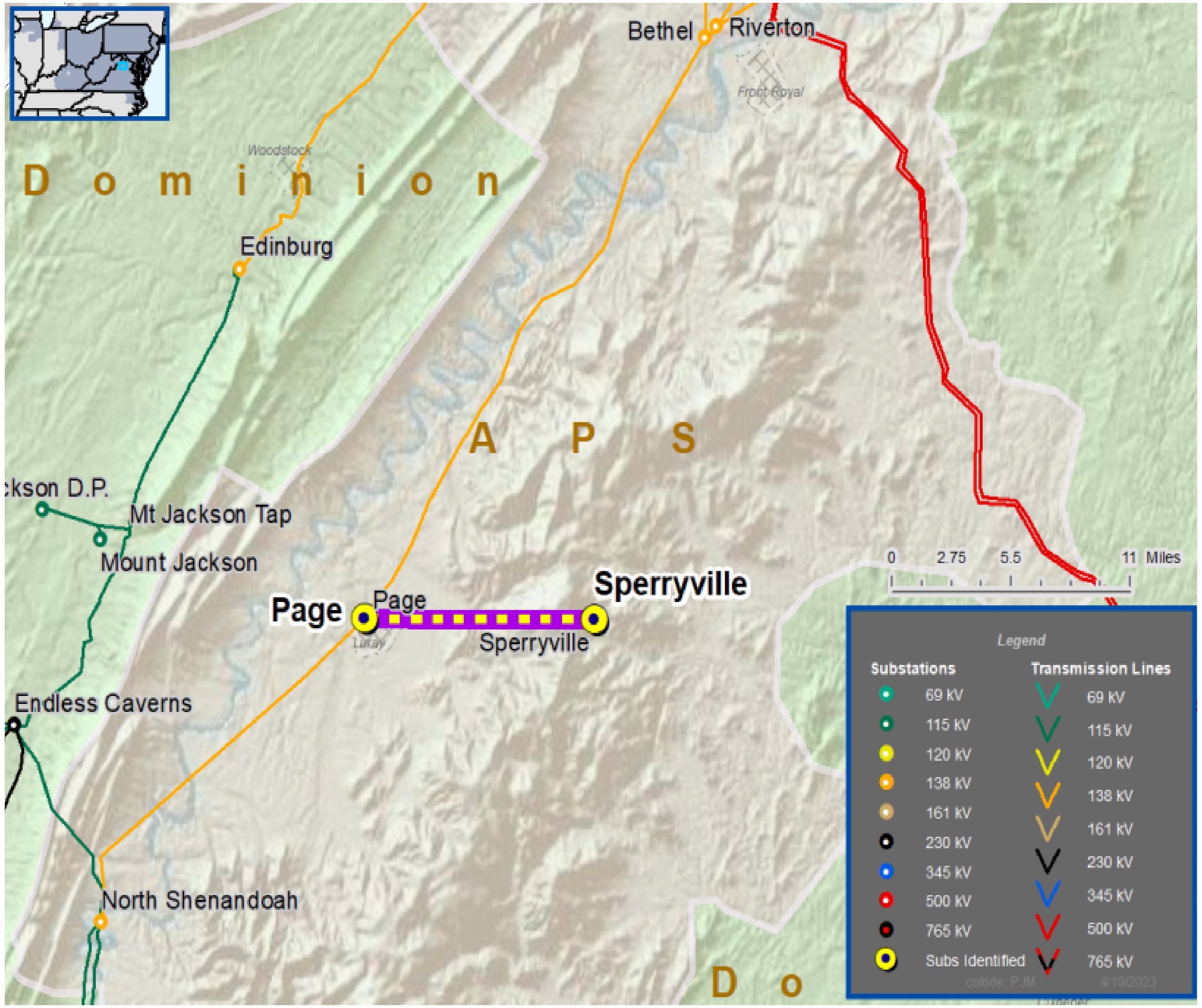
System Performance Projects Global Factors

- Substation/line equipment limits

Problem Statement:

The Page – Sperryville 138 kV line is exhibiting deterioration and has significant outage history

- Total line distance is approximately 13.8 miles.
- There is significant exposure to unplanned outages due to equipment failures and off ROW trees. Since 2014, there have been 15 outages including 5 equipment failures and 7 off ROW fall-ins
- Existing equipment is approaching expected end of life
- The terrain is extremely challenging, limiting access and extending outage durations to the supported municipal interconnection. The locations and design of structures further impedes repairs.



Need Number: APS-2023-005

Process Stage: Solution Meeting 04/21/2023

Proposed Solution:

- Rebuild the Page – Sperryville 138kV line, approximately 21.5 miles, with wood pole equivalent steel structures.
- Replace limiting substation conductor, wave trap, circuit breaker and relaying at Page 138 kV substation
- Replace limiting substation conductor, wave trap, and circuit switcher at Hardy 138 kV substation

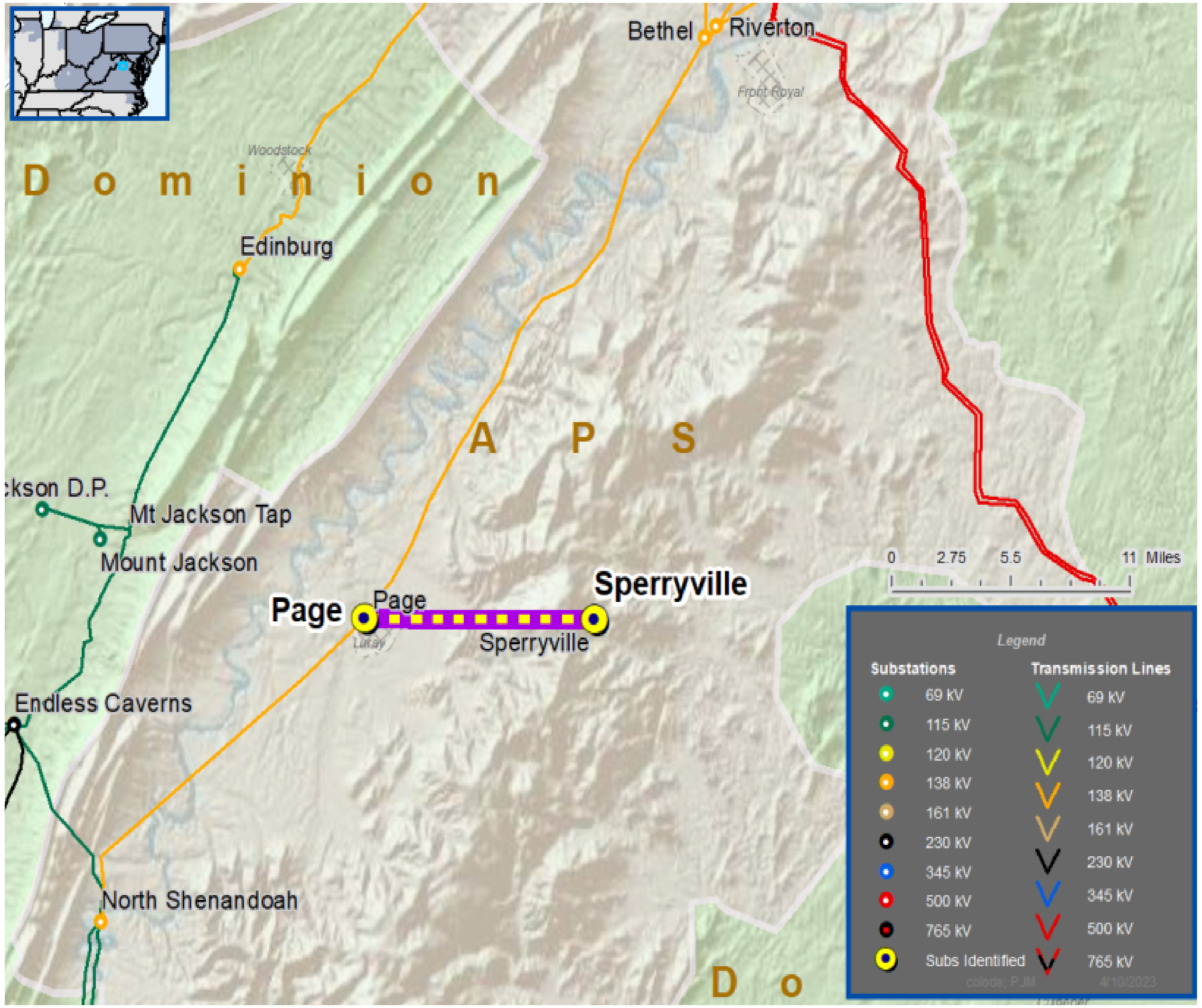
Transmission Line Ratings:

- Page – Sperryville 138 kV Line
  - Before Proposed Solution: 97 / 105 MVA (SN / SE)
  - After Proposed Solution: 309 / 376 MVA (SN / SE)

Alternatives Considered:

- Build a new greenfield line
- Maintain line in existing condition

Estimated Project Cost: $ 45.8 M
Projected In-Service: 6/1/2026
Project Status: Conceptual
Model: 2022 RTEP model for 2027 Summer (50/50)



Appendix

High Level M-3 Meeting Schedule

Assumptions

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

Needs

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

Solutions

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

Submission of Supplemental Projects & Local Plan

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

Revision History

4/xx/2022– V1 – Original version posted to pjm.com

Exhibit F: ATSI Supplemental Projects

Subregional RTEP Committee – Western
FirstEnergy Supplemental Projects

April 21, 2023

Needs

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

Need Number: ATSI-2023-002

Process Stage: Need Meeting – 04/21/2023

Supplemental Project Driver(s):

Equipment Material Condition, Performance and Risk

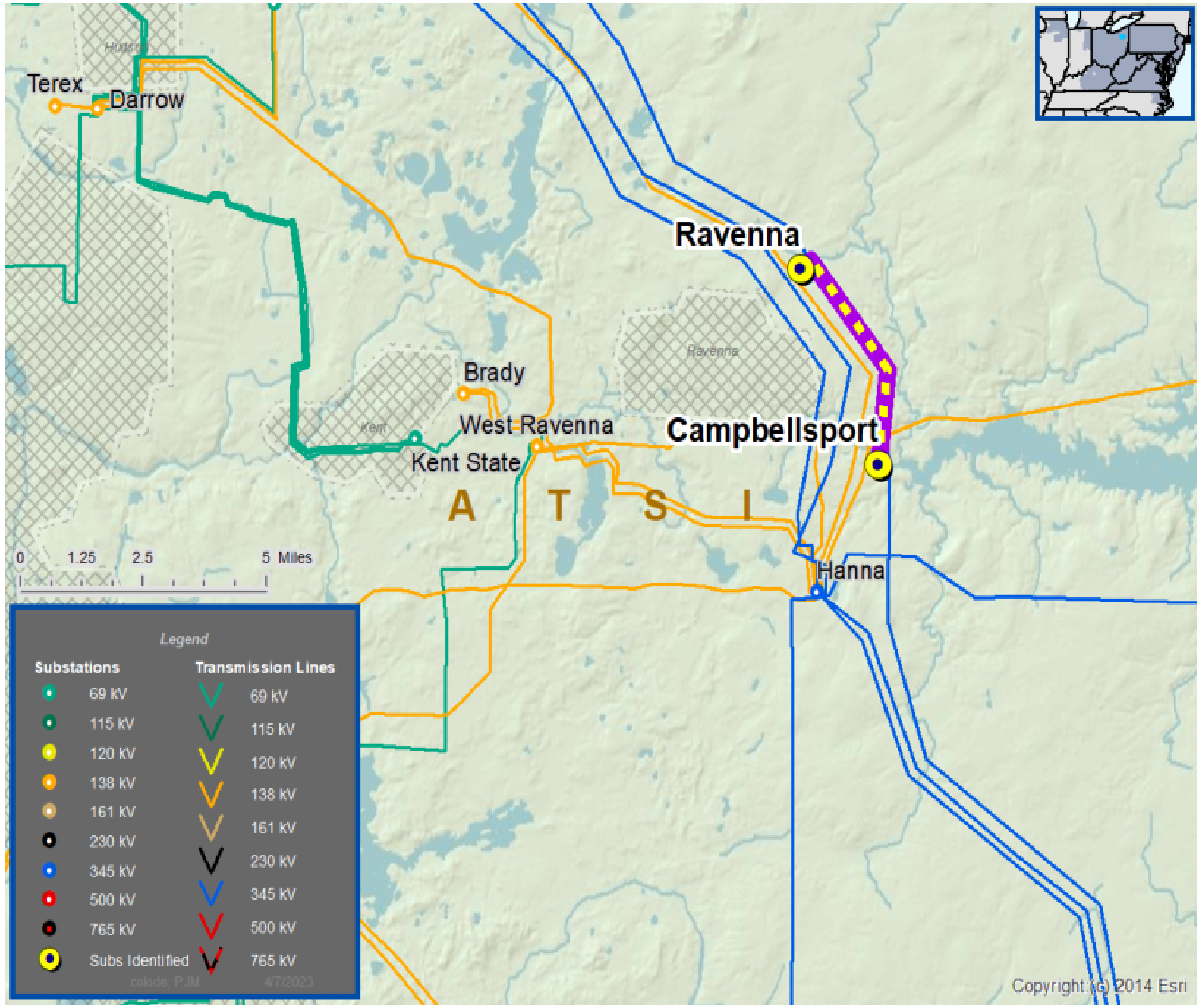
Specific Assumption Reference(s)

Line Condition Rebuild / Replacement

- Substation / Line equipment limits
- System reliability and performance
- Reliability of Non-Bulk Electric System (Non-BES) Facilities
- Transmission line with high loading

Problem Statement:

- Campbellsport - Ravenna #1 69 kV Line is 10.77 miles, and a 2.8 mile section of the line showed high loading (95% of Summer Emergency rating) using the 2021 RTEP 2026 Summer peak case for an N-1-1 outage.
- FE Transmission System Operations identified a potential real-time overload on the Campbellsport – Ravenna #1 69 kV Line and issued two PCLLRW's in two consecutive days 6/28/2021 & 6/29/2021 for the same N-1-1 outage noted above. (Line out for maintenance, plus next contingency)



FirstEnergy

ATSI Transmission Zone M-3 Process
South Akron 138 kV Substation Need

Need Number: ATSI-2023-009

Process Stage: Need Meeting – 04/21/2023

Supplemental Project Driver(s):

Operational Flexibility and Efficiency
Equipment Material Condition, Performance and Risk
Infrastructure Resilience

Specific Assumption Reference(s):

Global Considerations

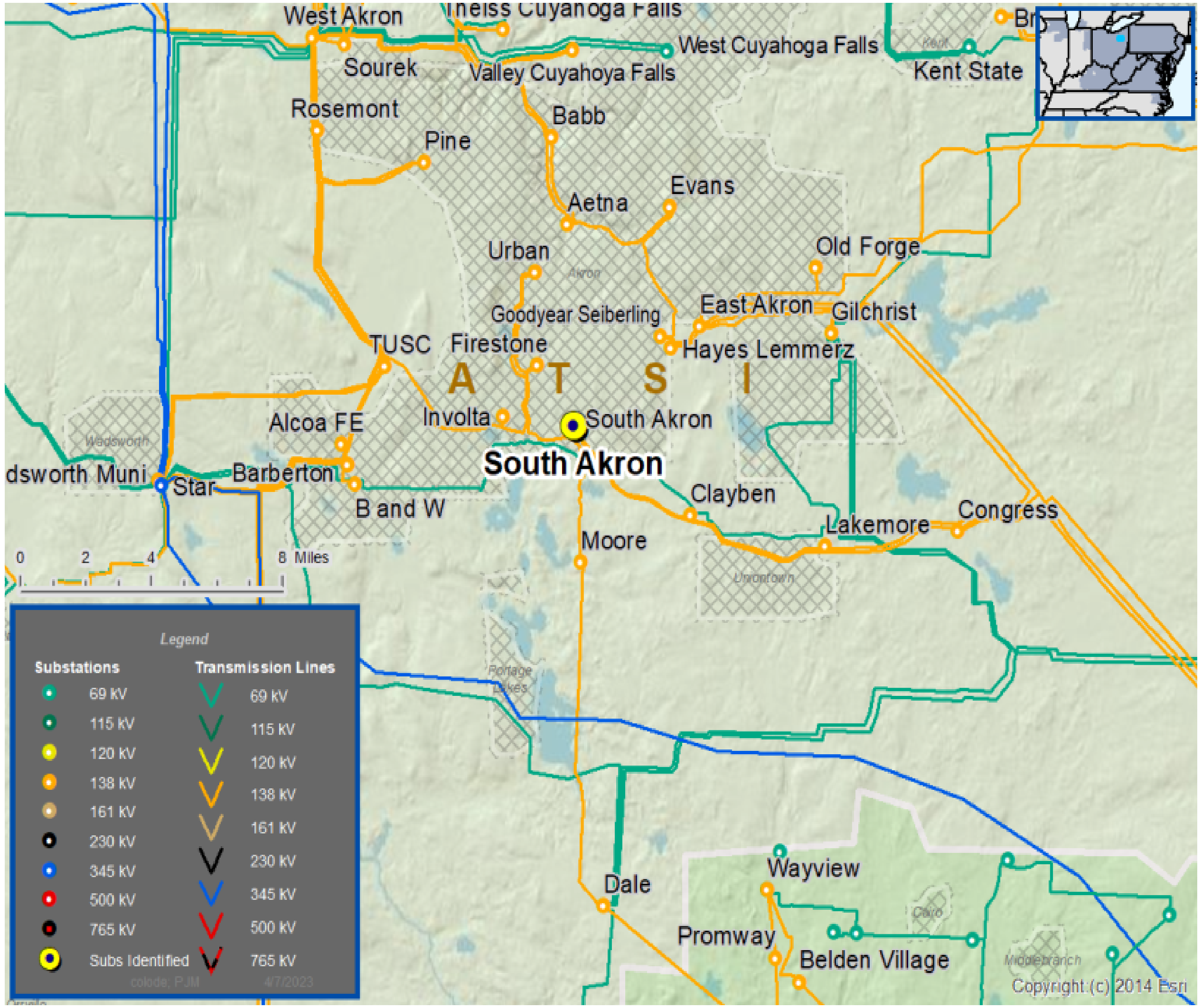
- System reliability and performance
- Load at risk in planning and operational scenarios

Substation Condition Rebuild/Replacement

- Increasing negative trend in maintenance findings and/or costs.
- Expected service life (at or beyond) or obsolescence

Add/Expand Bus Configuration

- Loss of substation bus adversely impacts transmission system performance
- Eliminate simultaneous outages to multiple networked elements under N-1 analysis
- Capability to perform system maintenance

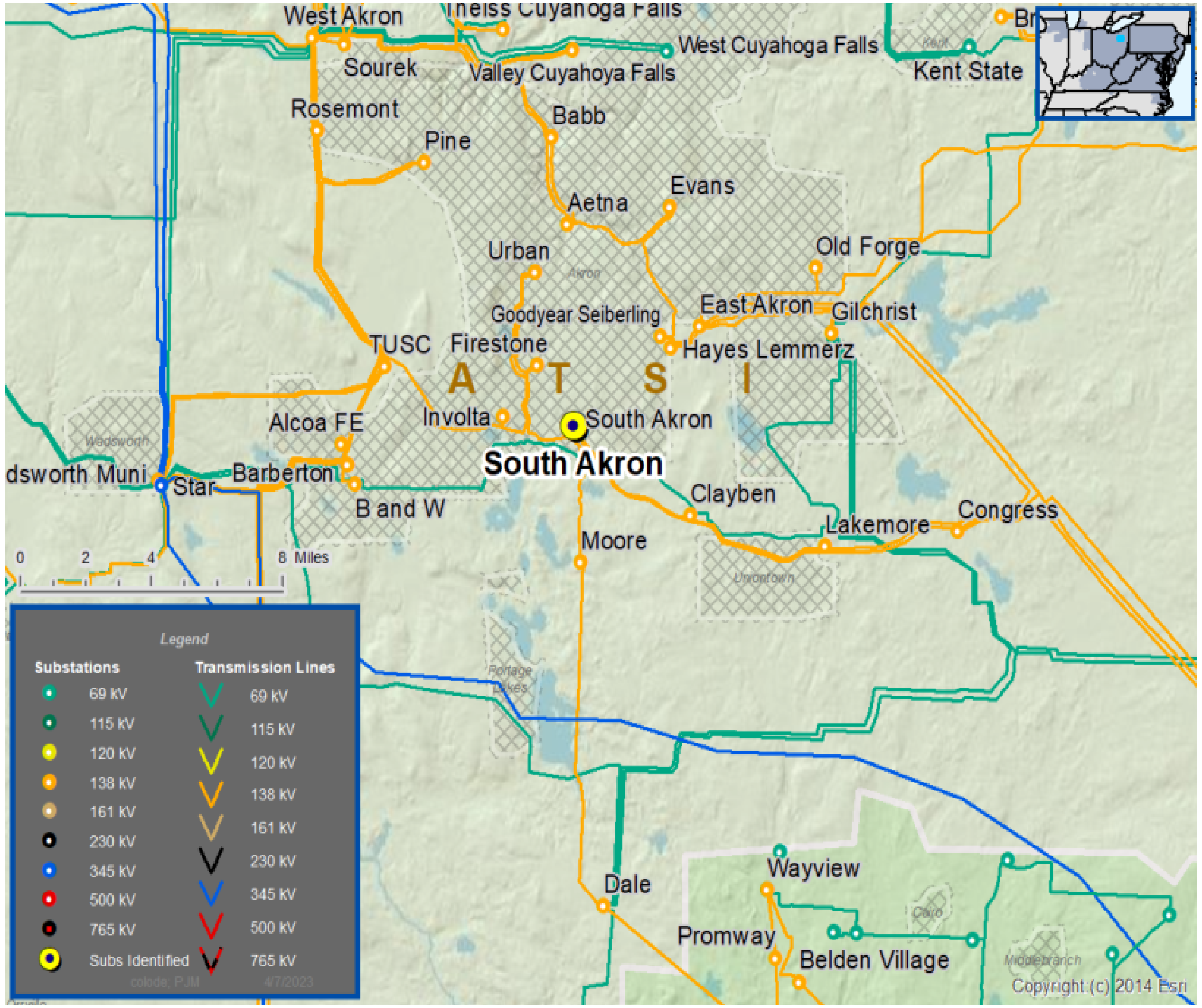


Need Number: ATSI-2023-009

Process Stage: Need Meeting – 04/21/2023

Problem Statement

- An N-1 bus outage at South Akron Substation results in the loss of approximately 55 MW and 17,000 customers.
- An N-1 bus outage at South Akron Substation results in several sub-transmission 23 kV lines overloaded beyond the summer emergency rating.
- The South Akron 138 kV bus protection consists of a non-redundant electromechanical (PVD) scheme
- 138 kV Breaker B-30 is 66 years old with increasing maintenance concerns; compressor issues, deteriorated operating mechanisms and increasing maintenance trends.
- 138 kV Breaker B-1 has a pneumatic mechanism
  - Manufacture date is 1952
  - Several corrective maintenance and preventive issues (magnetic loader failed, valve for pneumatic mechanism failed, replaced 52Y relay) and anticipated reoccurring failures
- 138 kV breaker B-10 has a pneumatic mechanism
  - Manufacture date is 1951
  - Several corrective maintenance and preventive issues (high ductor reading (high resistance on contact, air compressor for pneumatic mechanism failed, lower control valve failed for air charged to trip breaker) and anticipated reoccurring failures

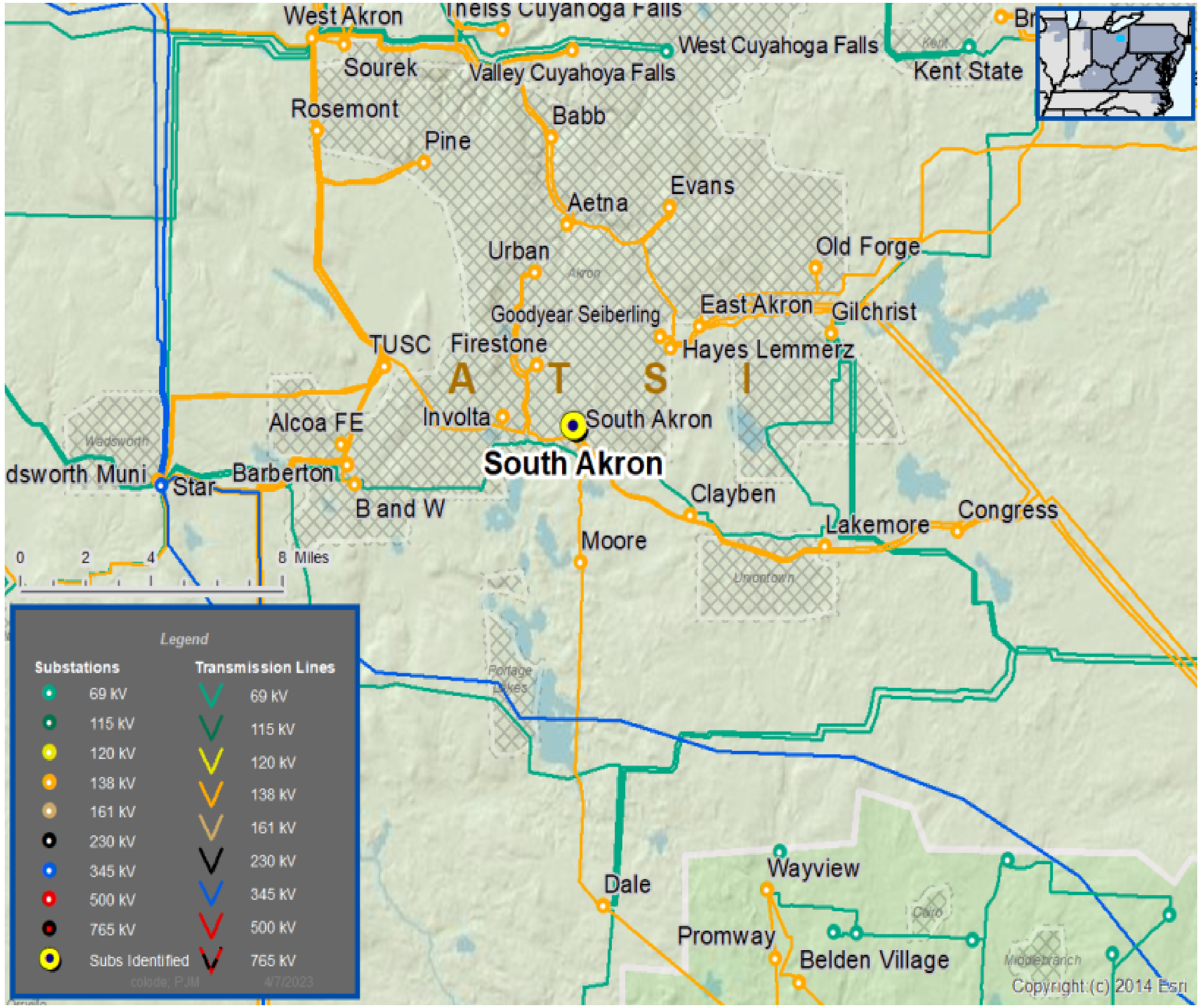


Need Number: ATSI-2023-009

Process Stage: Need Meeting – 04/21/2023

Problem Statement

- Since 2017, the South Akron 138 kV lines have experienced the following unscheduled outages:
  - The Dale-South Akron 138 kV line has one momentary and one sustained outage.
  - The Firestone-South Akron 138 kV line has one sustained outage.
  - The Lakemore-South Akron 138 kV line has one sustained outage.
  - The South Akron-Toronto 138 kV has five momentary and two sustained outages.



FirstEnergy

ATSI Transmission Zone M-3 Process
Chrysler-Maclean 138 kV New Customer

Need Number: ATSI-2023-003

Process Stage: Need Meeting – 4/21/2023

Project Driver(s):

Customer Service

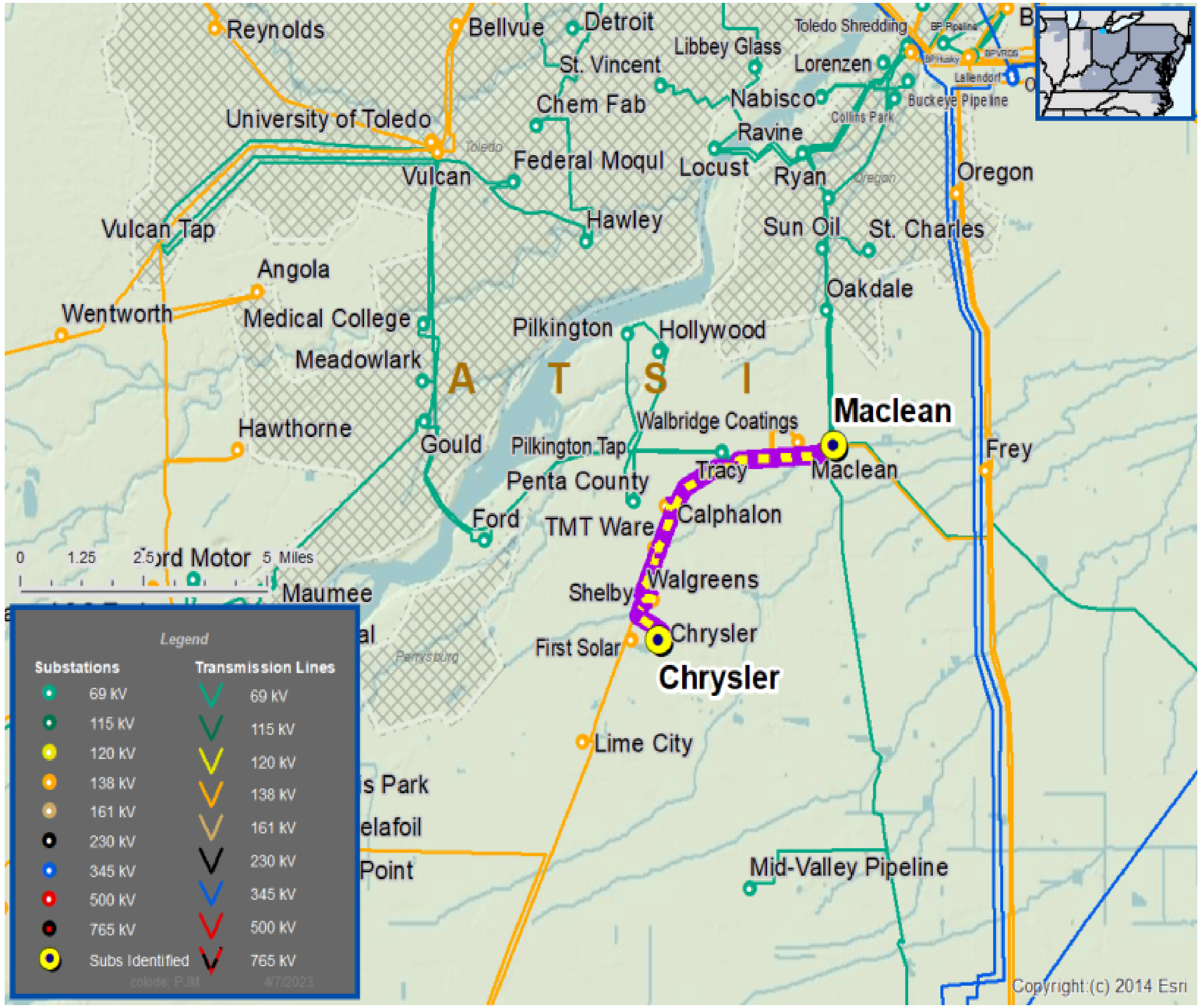
Specific Assumption Reference(s)

New customer connection request will be evaluated per FirstEnergy's "Requirements for Transmission Connected Facilities" document and "Transmission Planning Criteria" document.

Problem Statement

New Customer Connection – Customer has requested a new 138 kV delivery point near the Chrysler-Maclean 138 kV line. The anticipated load of the new customer connection is 30 MVA.

Requested in-service date is 10/01/2024.



Solution

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

ATSI Transmission Zone M-3 Process
Maysville 69 kV Area

Need Number: ATSI-2021-005
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 10/15/2021

Supplemental Project Driver(s):
Operational Flexibility and Efficiency
Equipment Material Condition, Performance and Risk

Specific Assumption Reference(s)
Global Considerations

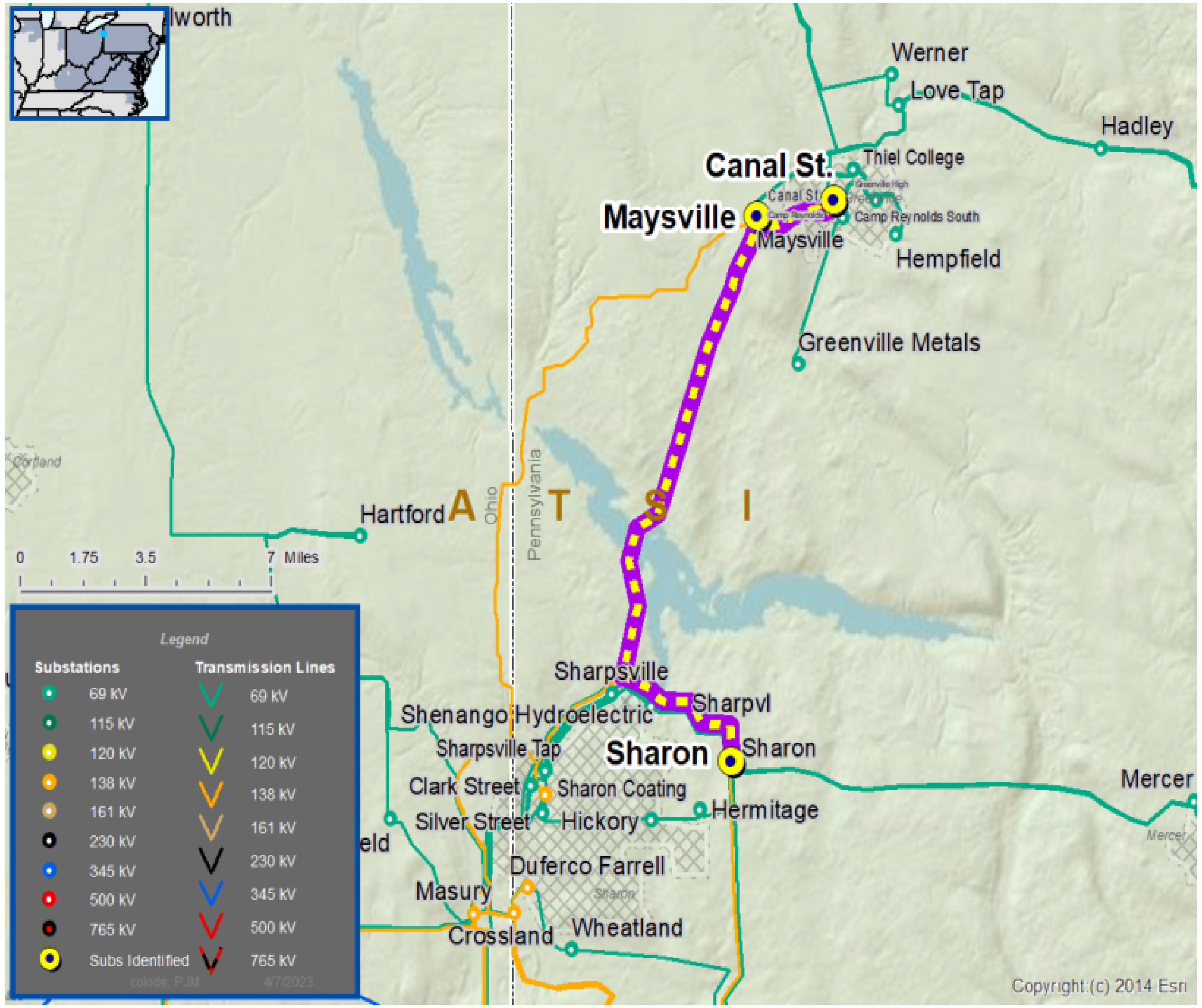
- System Reliability and Performance
- Substation/line equipment limits
- Reliability of Non-BES Facilities
- Load at risk in planning and operational scenarios.
- Load and/or customers at risk on single transmission lines

Network Radial Lines

- Load at risk and/or customers affected
- Proximity to other networked facilities

Build New Transmission Line

- Network radial lines

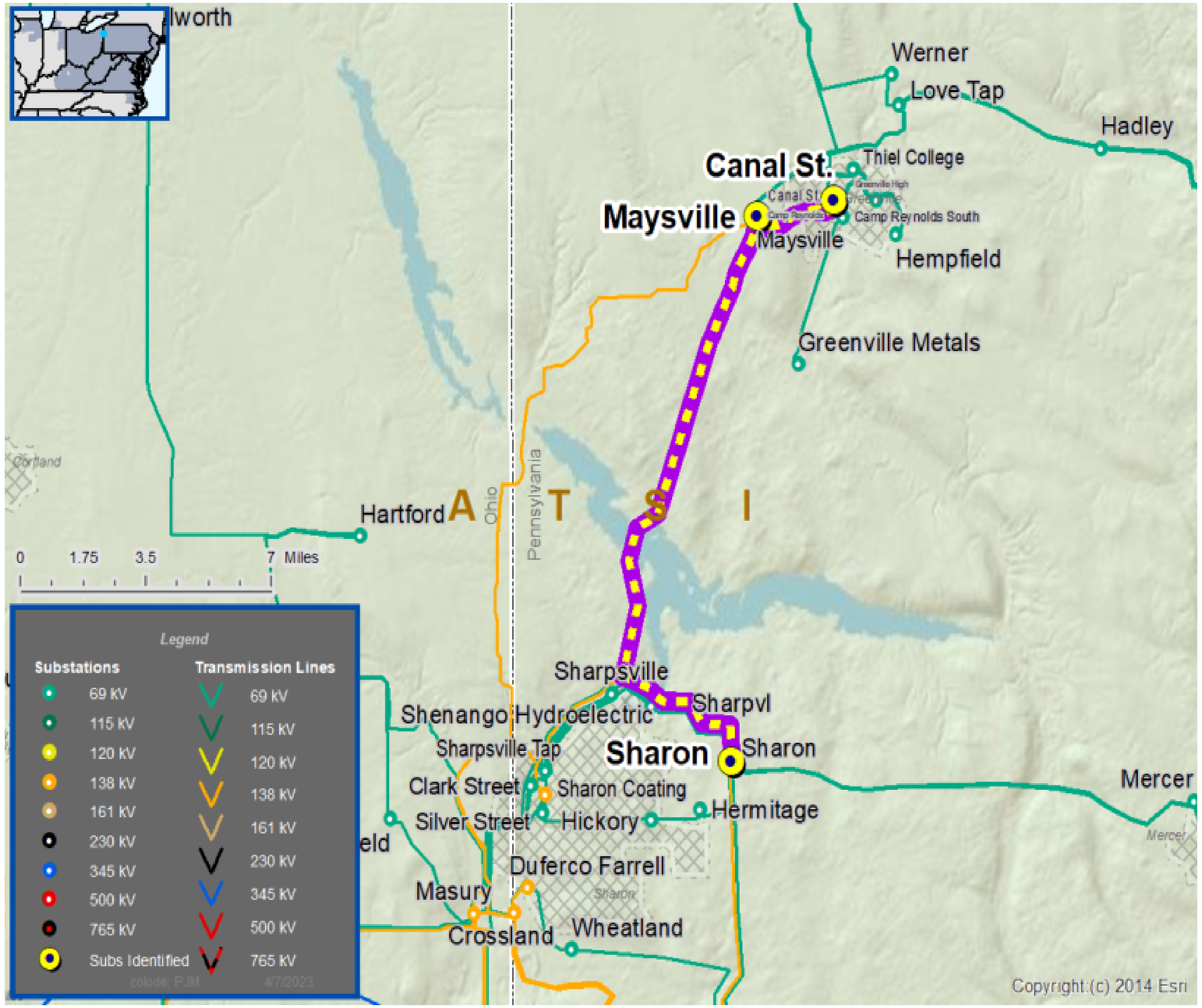


Need Number: ATSI-2021-005
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 10/15/2021

Problem Statement

Canal (Maysville) 69 kV Line

- The Canal (Maysville) Y-79 69 kV Line serves 14 MW and 6,500 customers on a ~3.6 mile radial
- A P1-2 contingency for the loss of the Canal (Maysville) Y-79 69 kV Line will outage roughly 14 MW and 6,500 customers
- The Canal (Maysville) Y-79 69 kV Line has experienced 1 sustained outage the past 5 years
- The Maysville-Sharon Y-301 69 kV Line serves 18 MW and 2,600 customers at two delivery points served on a ~2.7-mile tap
- A P1-2 contingency for the loss of the Maysville-Sharon Y-301 69 kV Line will outage roughly 18 MW and 2,600 customers
- The Maysville-Sharon Y-301 69 kV Line has experienced 4 sustained outages the past 5 years



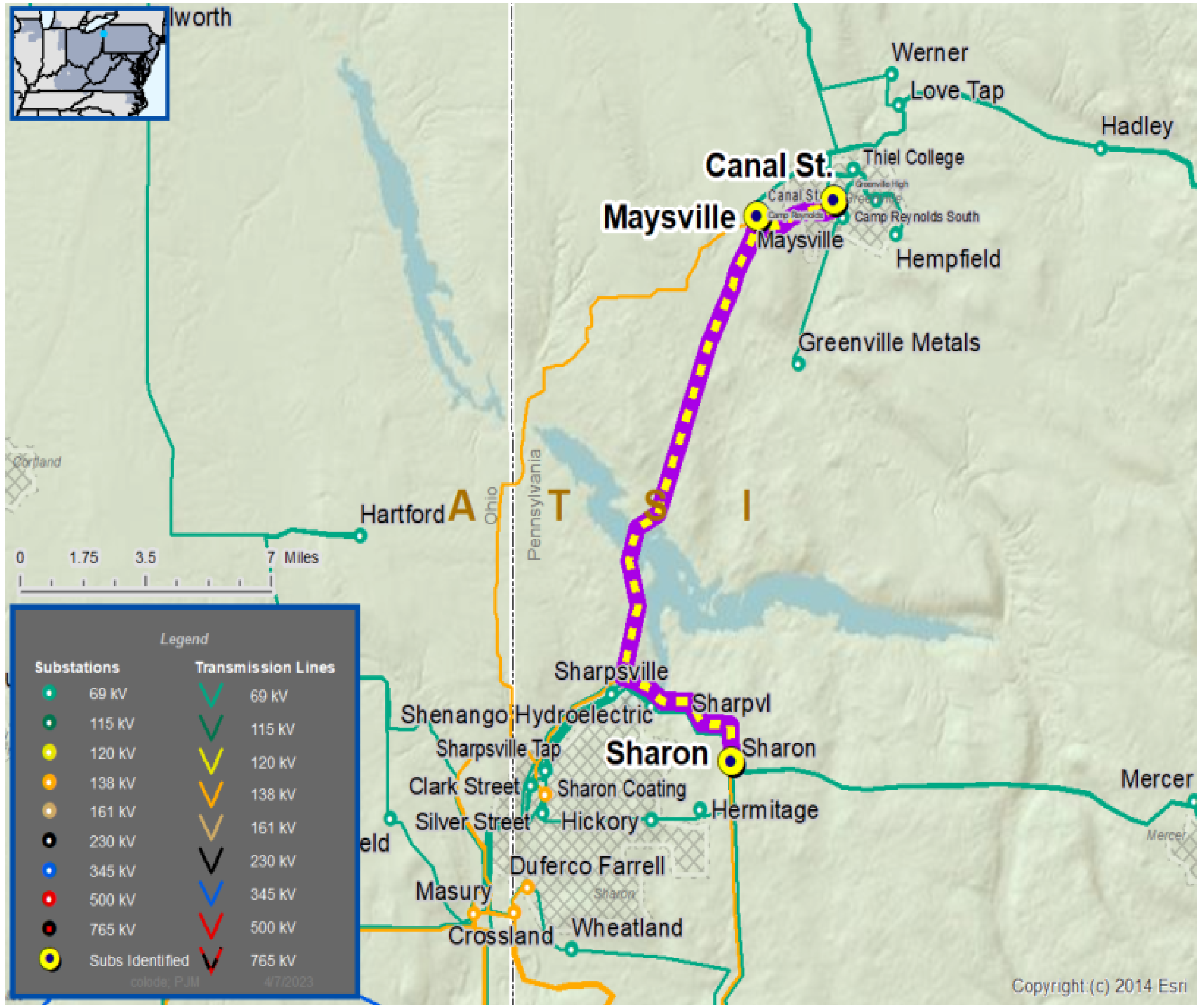
ATSI Transmission Zone M-3 Process
Maysville 69 kV Area

Need Number: ATSI-2021-005
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 10/15/2021

Proposed Solution:

- Remove switches A118 and A119 on the Maysville-Sharon Y-301 69 kV Line
- De-energize roughly 3.6 miles of the Maysville-Sharon 69 kV line from Maysville to the Camp Reynolds tap location.
- Remove switches A2153, A23, A2151, A260, A261 and A2152 at Greenville
- Build approximately 3.0 mi of 69 kV line connecting the Camp Reynolds (near TY19) tap to the Canal Tap (near TY104)
- Add 69 kV line switches with SCADA at Camp Reynolds tap, Greenville Metal tap, and Canal tap
- Add one 69 kV line switch with SCADA at Trinity tap

- **Transmission Line Ratings:**
- Maysville-Sharon Y301 69 kV Line
  - Before Proposed Solution: 69 MVA SN / 72 MVA SE
- Canal-Greenville 69 kV Line
  - Before Proposed Solution: 47 MVA SN / 56 MVA SE
- Sharon-Greenville 69 kV Line
  - After Proposed Solution: 47 MVA SN / 56 MVA SE

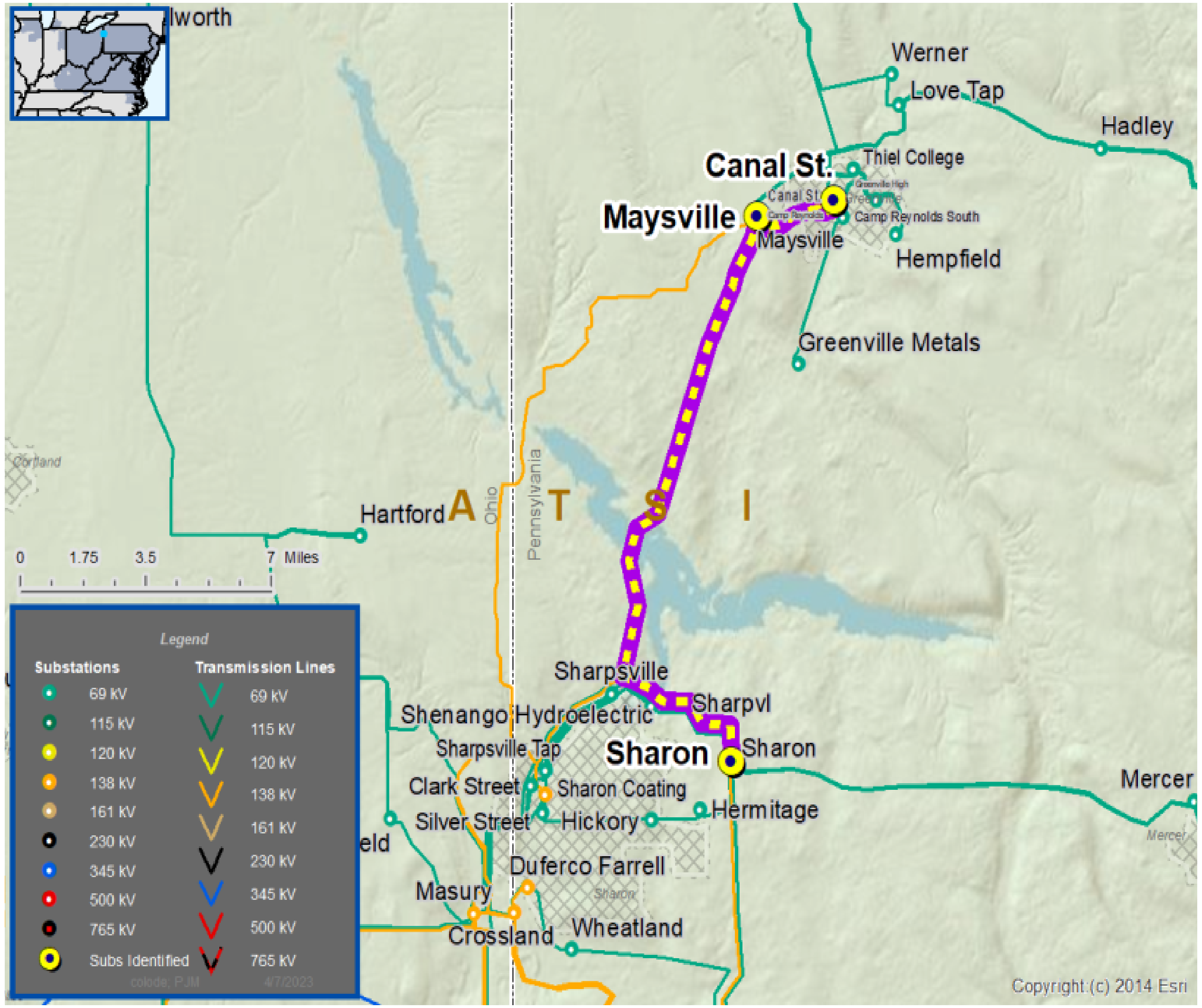


ATSI Transmission Zone M-3 Process
Maysville 69 kV Area

Need Number: ATSI-2021-005
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 10/15/2021

Alternatives Considered:
There were no reasonable alternatives to network the two radial 69 kV lines to improve the reliability of service to the customers served from the radial lines.

Estimated Project Cost: $12.2 M
Projected In-Service: 6/1/2025
Project Status: Engineering
Model: 2022 Series 2027 Summer RTEP 50/50



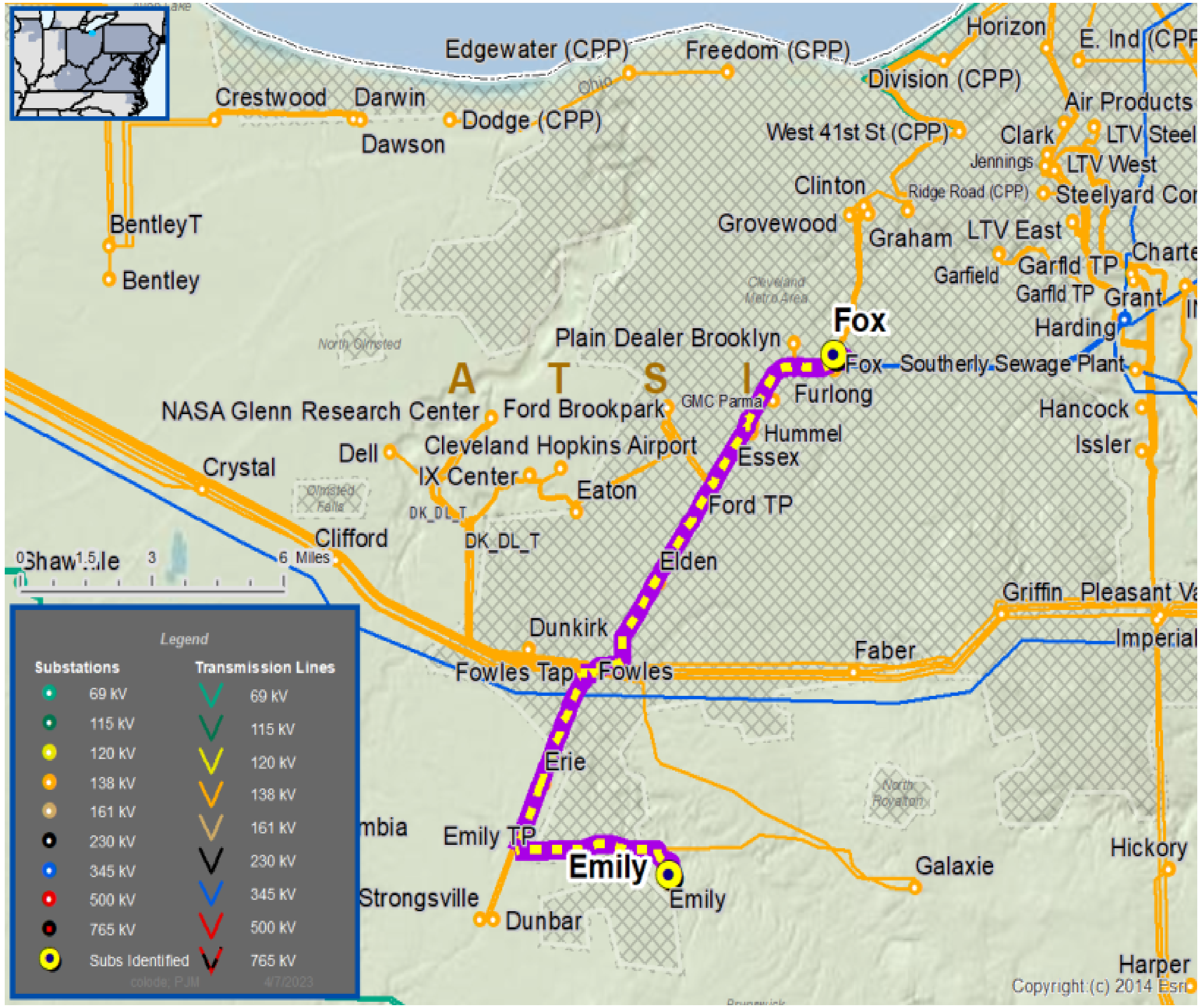
ATSI Transmission Zone M-3 Process
Emily-Fox 138 kV Q14 Line

Need Number: ATSI-2022-023
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 09/16/2022

Supplemental Project Driver(s):
Equipment Material Condition, Performance, and Risk
Infrastructure Resilience

Specific Assumption Reference(s):
Global Factors
- System Reliability and Performance
- Increase line loading limits
- Age/condition of transmission line conductors
- Line Condition Rebuild/Replacement

Problem Statement
- During inspection of the Emily-Fox 138 kV Line (approximately 19 miles), seven (7) wood pole structures failed sound testing and/or decay has been noted, as well as miscellaneous broken insulators, missing or broken grounds, hardware, braces, climbing pegs, etc



ATSI Transmission Zone M-3 Process
Emily-Fox 138 kV Q14 Line

Need Number: ATSI-2022-023
Process Stage: Solution Meeting – 04/21/2023
Previously Presented: Need Meeting – 09/16/2022

Proposed Solution:

Fowles 138 kV Substation

- Replace existing 500 Cu strain bus at Fowles 138 kV (Emily – Fox 138 kV Line is routed through Fowles 138 kV Station)

Emily – Fox Q14 138 kV Line

- Replace and upgrade seven (7) wood pole structures on Emily – Fox 138 kV Q14 Line
- Replace damaged and worn insulators on ten (10) additional structures

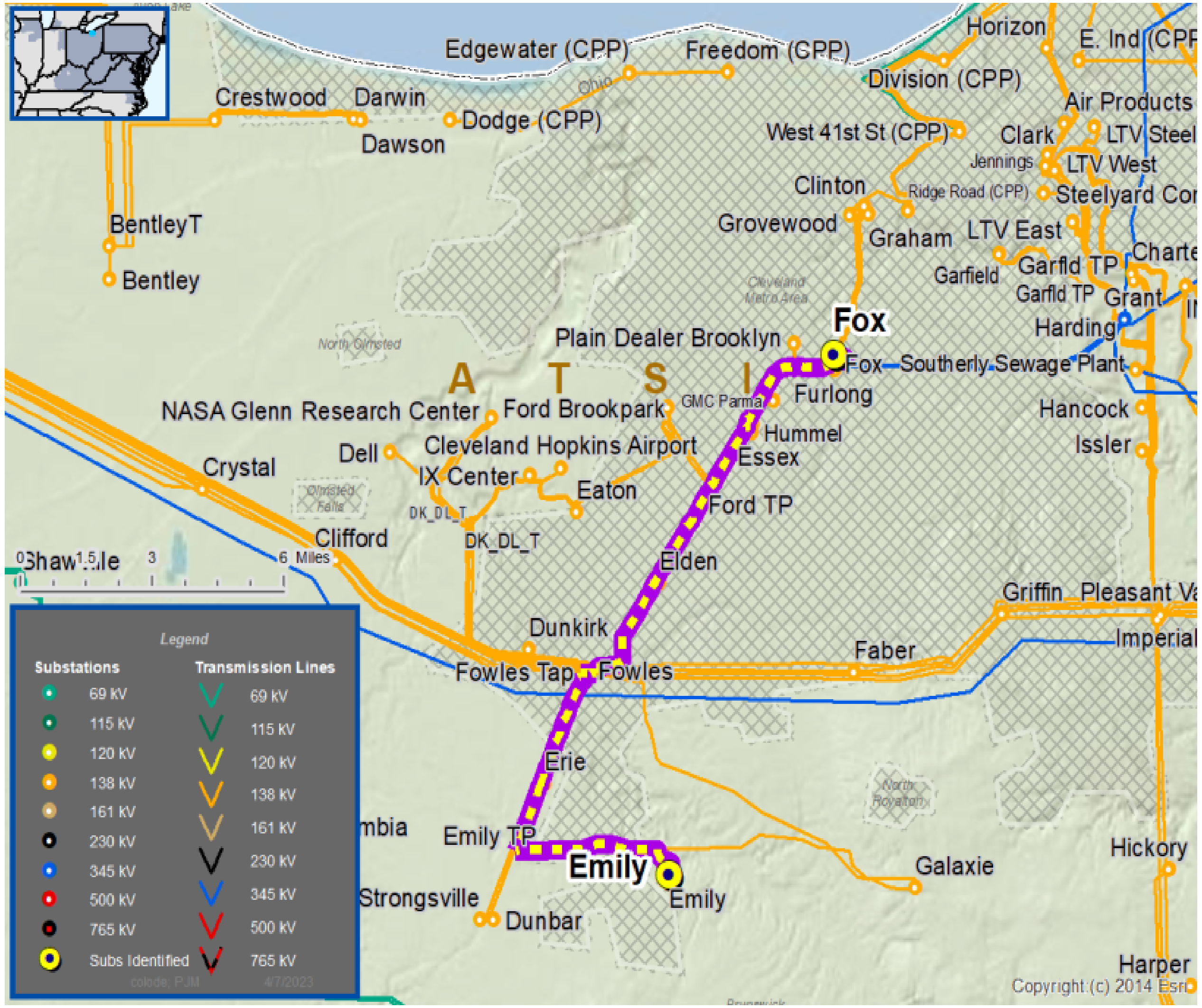
Transmission Line Ratings:

- Existing Galaxie – Hummel Tap line section rating: 176 SN / 229 SE / 253 WN / 284 WE
- New Galaxie – Hummel Tap line section rating: 347 SN / 423 SE / 393 WN / 501 WE

Alternatives Considered:

- Maintain existing condition and elevated risk of wood pole/insulator failures, increasing maintenance costs, and reduced transmission line loadability during peak conditions.

Estimated Project Cost: $1.1M
Projected In-Service: 12/31/2023
Status: Engineering
Model: 2022 Series 2027 Summer RTEP 50/50



Re-Present Solutions

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

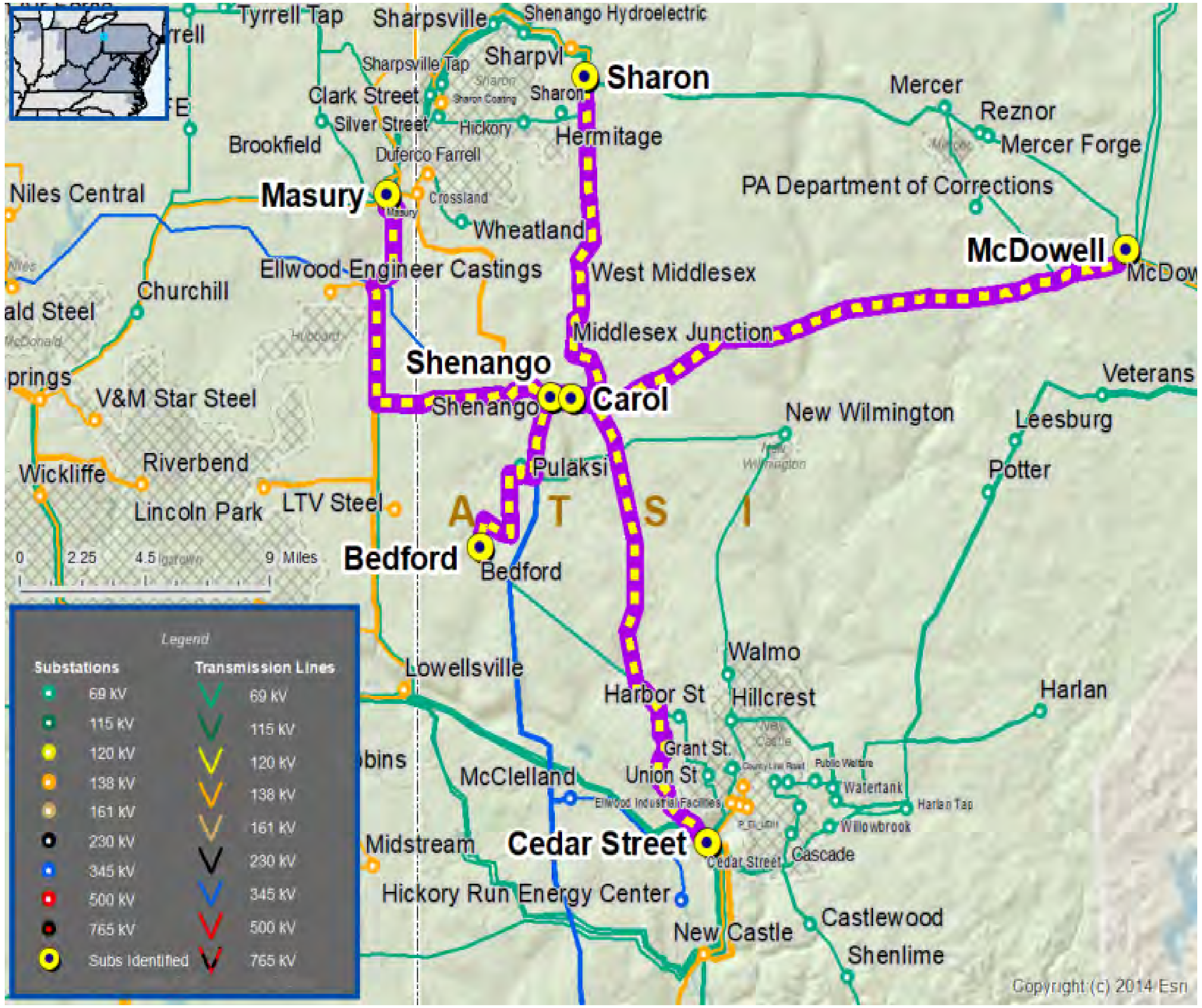
ATSI Transmission Zone M-3 Process
Carol 138-69 kV Switching Station

Need Number: (s1712)
Process Stage: Re-Present Solutions Meeting – 04/21/2023
Previously Presented: Need Meeting – 8/31/2018
Solution Meeting – 9/28/2018

Supplemental Project Driver(s):
Operational Flexibility and Efficiency

Specific Assumption Reference(s):
Global Factors
- Load Loss
- System Reliability and Performance

Problem Statement
- Improve operational flexibility during maintenance and restoration efforts.
- Reduce amount of potential local load loss (Approximately 35 MWs worse case) under multiple (P1) contingency conditions on the 69 kV system.
    - Loss of the Cedar Street-Cascade (Walmo) 69 kV normally open radial line
- Improve relay coordination and network normally open 69 kV lines.
- Approximately 21,000 customers and radial load of 86 MWs at risk in the area.



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FirstEnergy

ATSI Transmission Zone M-3 Process
Carol 138-69 kV Switching Station

Need Number: (s1712)

Process Stage: Re-Present Solutions Meeting – 04/21/2023

Previously Presented: Need Meeting – 8/31/2018

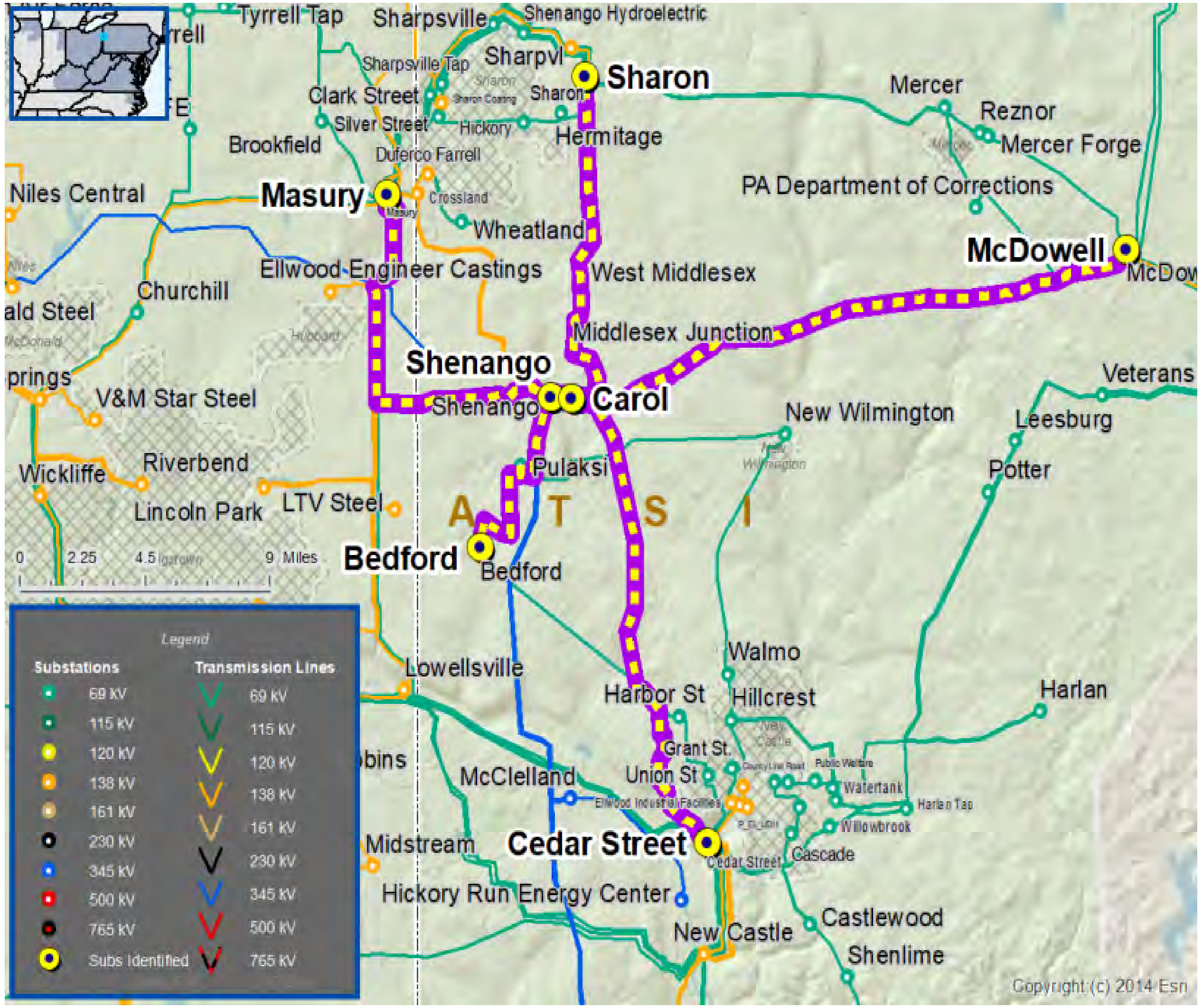
Solution Meeting – 9/28/2018

Proposed Solution:

~~*Shenango 69 kV Switching Station*~~

- ~~Network radial 69 kV system by constructing two double circuit 477 ACSR 69 kV lines (~ 1.2 miles) to create four (4) new 69 kV circuits from the new Shenango 69 kV station~~
  - ~~Shenango-Masury 69 kV line~~
  - ~~Shenango-Sharon 69 kV line~~
  - ~~Shenango-Cedar Street #1 69 kV line~~
  - ~~Shenango-Cedar Street #2 69 kV line~~
- ~~Install two (2) 138/69 kV transformers at Shenango~~
- ~~Expand Shenango substation to create a six (6) breaker 69 kV ring bus~~

Shenango substation is built in a floodplain with significant challenges, including permitting and environmental mitigation costs.



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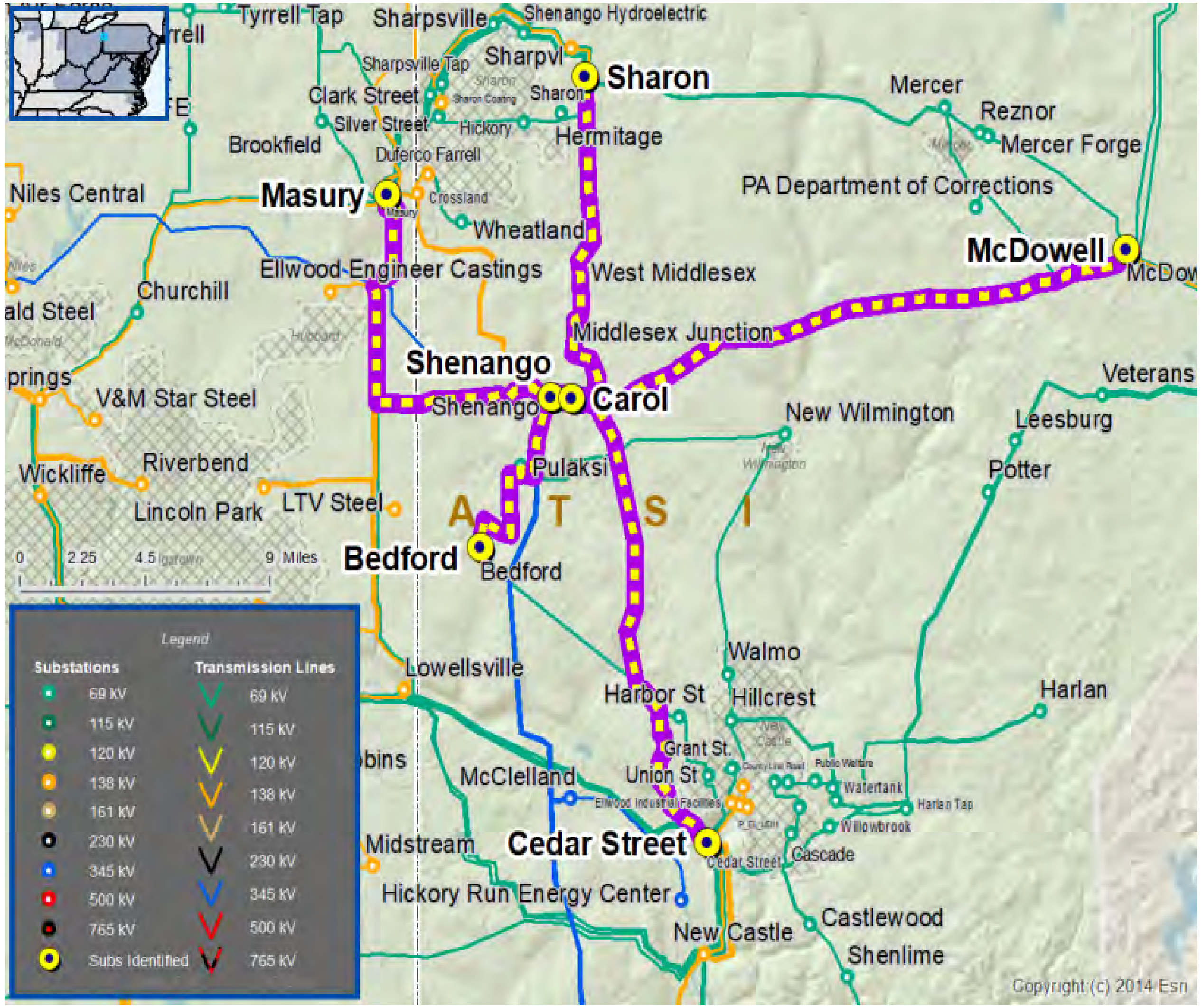
Need Number: (s1712)

Process Stage: Re-Present Solutions Meeting – 04/21/2023

Previously Presented: Need Meeting 8/31/2018
Solution Meeting – 9/28/2018

Proposed Solution:

- Carol 138-69 kV Switching Substation
- Construct a new 138 kV 6-breaker ring bus substation near the Shenango Substation (Future 12-Breaker Breaker-and-a-Half).
- Loop in the Cedar Street-Shenango and Shenango-McDowell 138 kV lines into the new substation.
- Construct a new 69 kV six-breaker ring bus adjacent to the new 138 kV substation.
- Loop in the Cedar Street-Masury-Sharon 69 kV line, undo the six-wire configuration between structures #169 and #216 to create four new 69 kV circuits out of the new Carol 69 kV Substation.
- Rebuild and reconductor approximately 3.0 miles
- Install (2) 138-69 kV 100/134 MVA transformers
- Install new control building



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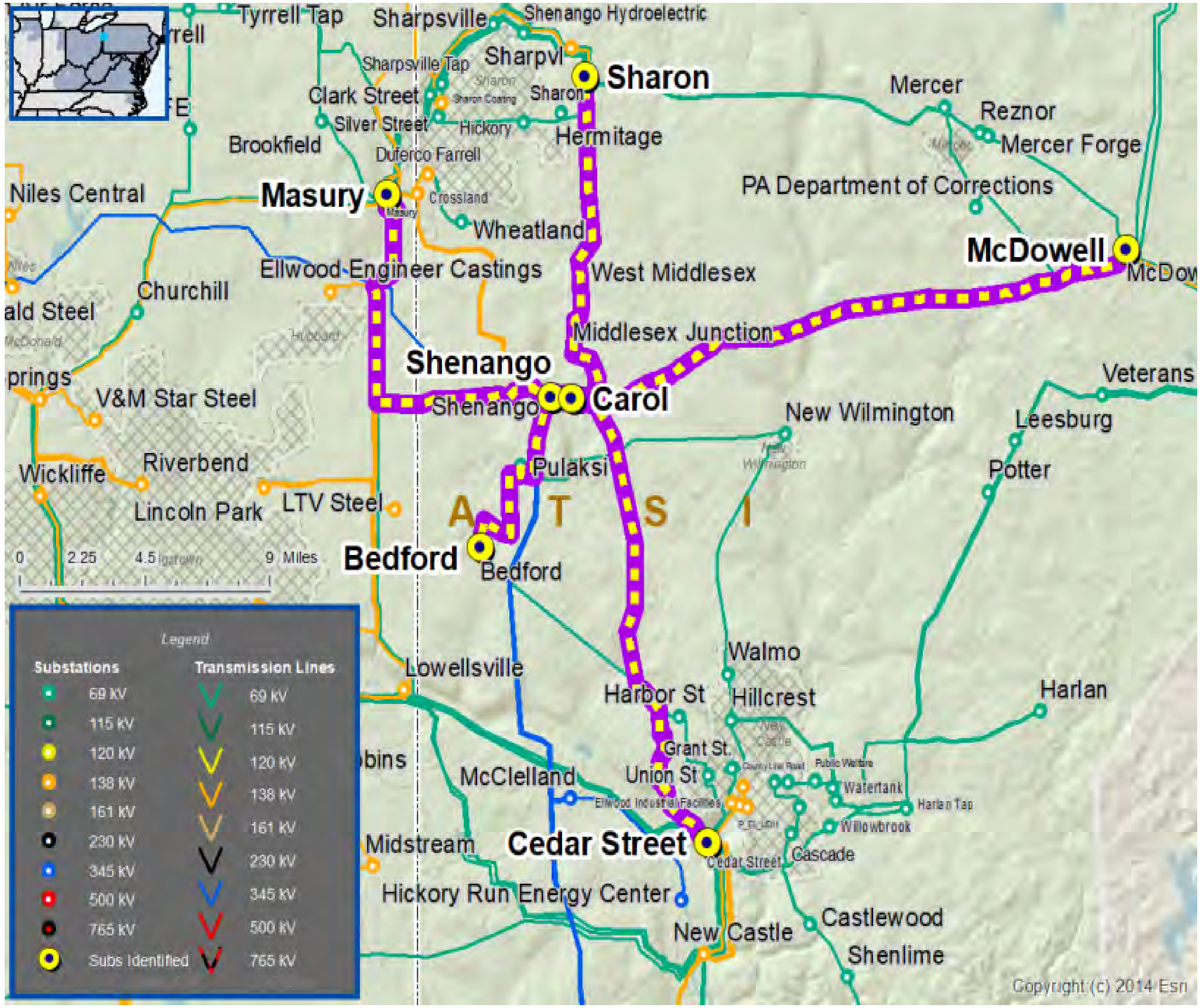
ATSI Transmission Zone M-3 Process
Carol 138-69 kV Switching Station

Need Number: (s1712)
Process Stage: Re-Present Solutions Meeting – 04/21/2023
Previously Presented: Need Meeting 8/31/2018
Solution Meeting – 9/28/2018

Proposed Solution:

- At Masury:
  - Replace Y-188 (B17) 69 kV line relaying and control with standard relay panel
- At Sharon:
  - Replace Y-188/Y-303 (B6) 69 kV line relaying and control with standard relay panel
  - Replace the limiting disconnect switch
- At Shenango:
  - Replace 138 kV breaker (B48) and line relaying
  - Replace two 138 kV breaker disconnect switches (D37 & D43)
  - Upgrade the terminal equipment (line drops) to exceed the TL rating
- At McDowell:
  - Upgrade the terminal equipment (substation conductor) to exceed the TL rating



Continued on next slide…

FirstEnergy

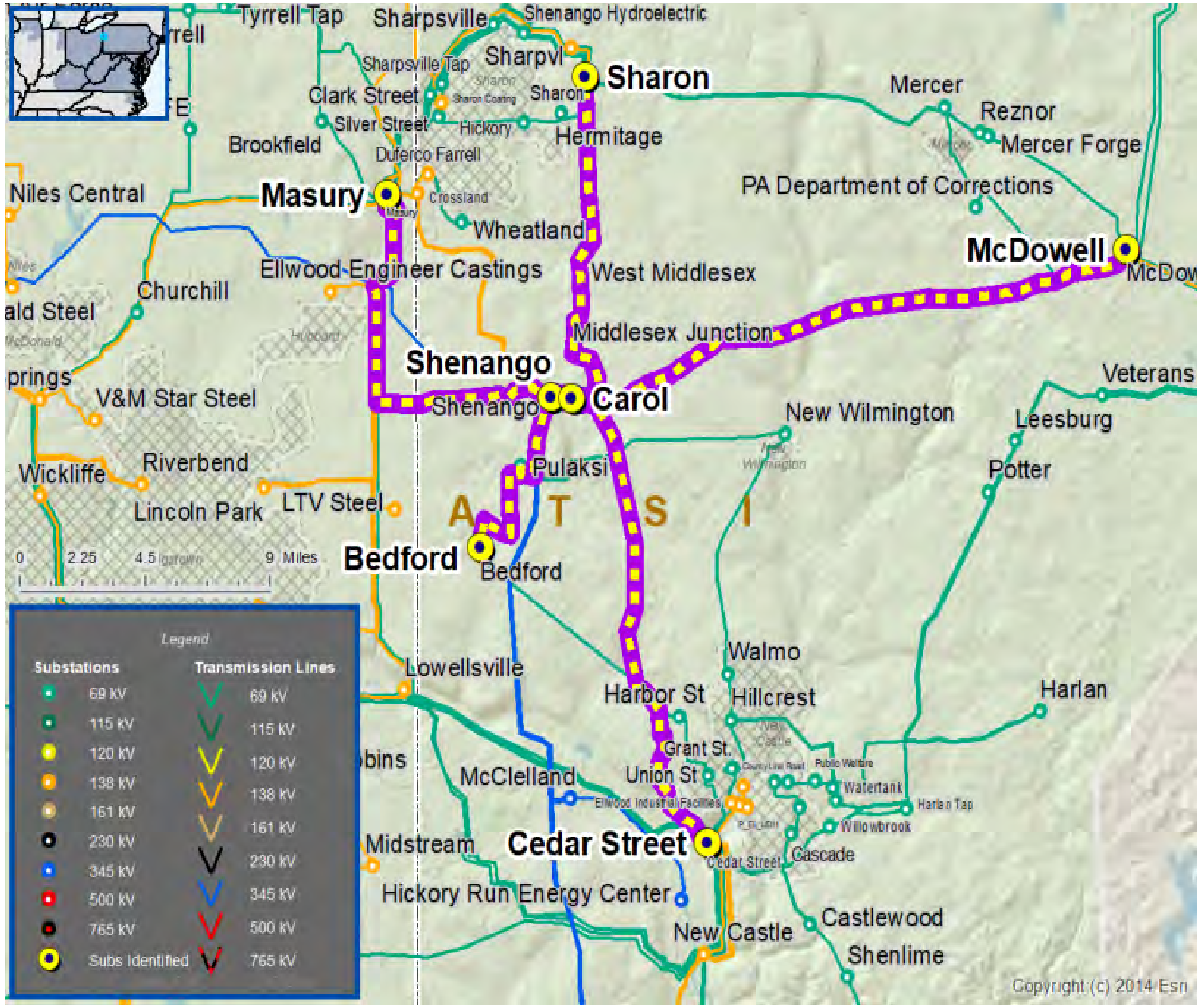
Need Number: (s1712)
Process Stage: Re-Present Solutions Meeting – 04/21/2023
Previously Presented: Need Meeting – 8/31/2018
Solution Meeting – 9/28/2018

Proposed Solution:

Transmission Line Ratings:

Existing Lines:

- Cedar Street-Shenango 138 kV Line:
  - SN: 278 MVA SE: 339 MVA WN: 315 MVA WE: 401 MVA
- McDowell-Shenango 138 kV Line:
  - SN: 265 MVA SE: 309 MVA WN: 309 MVA WE: 309 MVA
- Cedar Street-Masury-Sharon 69 kV Line:
  - SN: 94 MVA SE: 113 MVA



Continued on next slide…

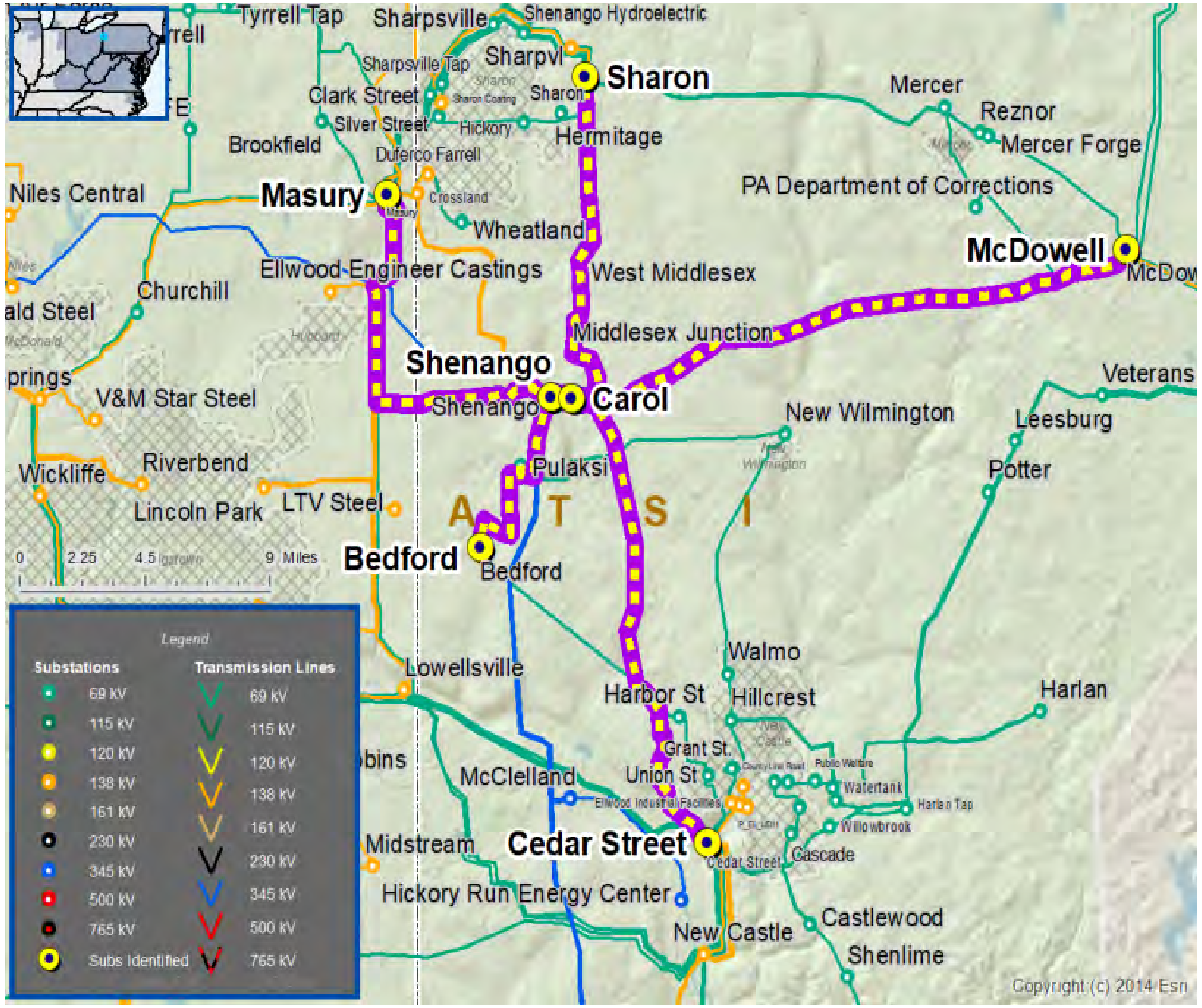
Need Number: (s1712)
Process Stage: Re-Present Solutions Meeting – 04/21/2023
Previously Presented: Need Meeting – 8/31/2018
Solution Meeting – 9/28/2018

Proposed Solution:

Transmission Line Ratings:

New Lines:

- Carol-Sharon 69 kV Line:
  - SN: 100 MVA SE: 121 MVA WN: 113 MVA WE: 143 MVA
- Carol- Masury 69 kV Line:
  - SN: 80 MVA SE: 96 MVA WN: 90 MVA WE: 114 MVA
- Carol- Pulaski (#1) 69 kV Line (Cedar Street):
  - SN: 80 MVA SE: 96 MVA WN: 90 MVA WE: 114 MVA
- Carol- Bedford (#2) 69 kV Line (Cedar Street):
  - SN: 94 MVA SE: 113 MVA WN: 105 MVA WE: 133 MVA
- Carol-Shenango (#1) 138 kV Line:
  - SN: 278 MVA SE: 339 MVA WN: 315 MVA WE: 401 MVA
- Carol-Cedar St (#1) 138 kV Line:
  - SN: 278 MVA SE: 339 MVA WN: 315 MVA WE: 401 MVA
- Carol-Shenango (#2) 138 kV Line:
  - SN: 278 MVA SE: 339 MVA WN: 315 MVA WE: 401 MVA
- Carol-McDowell (#2) 138 kV Line:
  - SN: 278 MVA SE: 339 MVA WN: 315 MVA WE: 401 MVA



Continued on next slide…

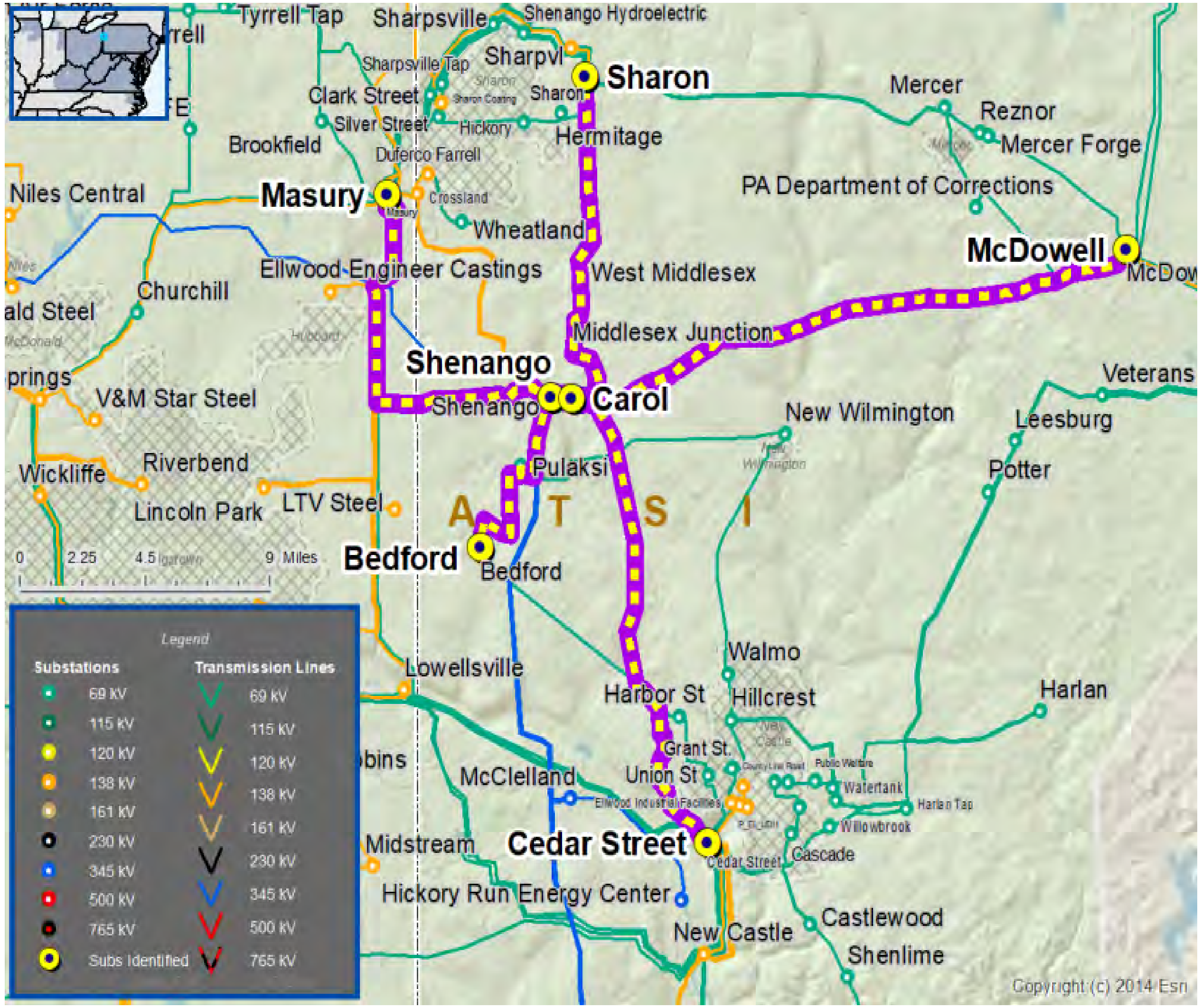
ATSI Transmission Zone M-3 Process
Carol 138-69 kV Switching Station

Need Number: (s1712)
Process Stage: Re-Present Solutions Meeting – 04/21/2023
Previously Presented: Need Meeting – 8/31/2018
Solution Meeting – 9/28/2018

Proposed Solution:

Alternatives Considered: Network radial 69 kV system by constructing two double circuit 477 ACSR 69 kV lines (~ 1.2 miles) to create four (4) new 69 kV circuits from the new Shenango 69 kV station. Install two (2) 138-69 kV transformers at Shenango. Expand Shenango substation to create a six (6) breaker 69 kV ring bus.

Estimated Project Cost: ~~$16.3M~~ $45M
Project IS Date: ~~12/31/2021~~ 12/1/2025
Model: 2022 RTEP model for 2027 Summer (50/50) Case
Status: ~~Conceptual~~ Pre-Engineering



Appendix

High Level M-3 Meeting Schedule

Assumptions

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

Needs

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

Solutions

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

Submission of Supplemental Projects & Local Plan

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

Revision History

4/xx/2022– V1 – Original version posted to pjm.com

Exhibit G: Transmission Owner Projects

<u>Transmission Owner Projects – presented as part of the April PJM M-3 Process</u>

When: April Subregional meetings
What: Regulatory Public Utility Commission oversight review (e.g. CPCN)
Needs Presented: 49
Solutions Presented: ~~24~~ 23 at an estimated cost of ~~$579.38~~ $476.38 million

- ~~17~~ 16 of these solutions have no state commission oversight (~~$298.78~~ $195.78 million)

Subregional RTEP Committee – Southern (April 20, 2023)

Link: [PJM - Meeting Details]

Needs: 3 Dominion

Solutions: 0

Subregional RTEP Committee – Mid-Atlantic (April 20, 2023)

Link: [PJM - Meeting Details]

Needs offered by: 9 (UG1, JCPL, Met-Ed, PPL, and BGE)

Solutions offered: 6 + 1 re-solution [revised 5 +1]

- **No state utility commission oversight = 5 projects $178.25 million**
- **Revised: No state utility commission oversight = 4 projects $75.25 million**
  - **PPL stated in the Planning Community that PPL-2019-0005 need/solution was withdrawn ($103 million)**

- **State utility commission oversight = 1 ($23.96)**

Re-solutions offered: 1 (DPL) $9.57 million

Total no state utility commission oversight = $178.25 + $9.57 = $187.82 million
Revised: Total no state utility commission oversight = $75.25 + $9.57= $84.82 million

Solutions

FirstEnergy (Met-Ed)

1. Need Number: ME-2022-003
   a. Need Presented: 4/19/2022
   b. Estimated Projects Costs: $0.8 million
   c. Alternatives considered: None
   d. Projected-in-service date: 12/29/2023
   e. Projected oversight: PA-No state utility commission regulatory oversight

2. Need Number: ME-2019-044
    a. Need Presented: 7/31/2019
    b. Estimated Projects Costs: $10.3 million
    c. Projected-in-service date: 12/31/2027
    d. Alternatives considered: *Maintain existing condition
    e. Projected oversight: PA?? - No state utility commission regulatory oversight

PSEG

3. Need Number: PSEG-2023-0003
    a. Need Presented: 3/16/2023
    b. Estimated Projects Costs: $63 million
    c. Projected-in-service date: 12/2027
    d. Alternatives considered: yes
    e. Projected oversight: NJ - No state utility commission regulatory oversight

FirstEnergy (Penelec)

4. Need Number: PN-2023-002
    a. Need Presented: 3/16/20
    b. Estimated Projects Costs: $1.15 million
    c. Projected-in-service date: 5/12/2023
    d. Alternatives considered: no
    e. Projected oversight: PA - No state utility commission regulatory oversight

5. Need Number: PN-2022-004
    a. Need Presented: 12/14/2022
    b. Estimated Projects Costs: $23.96 million
    c. Projected-in-service date: 4/1/2025
    d. Alternatives considered: yes
    e. Projected oversight: PA - State utility commission regulatory oversight

PPL

~~6. Need Number: PPL-2019-0005~~
    ~~a. Need Presented: 2/22/2019~~
    ~~b. Estimated Projects Costs: $103 million~~
    ~~c. Projected-in-service date: 12/30/2028~~
    ~~d. Alternatives considered: yes~~
    ~~e. Projected oversight: PA – No state utility commission regulatory oversight~~

**Note: Re-solution

1. Need Number: DPL-2021-001
    a. Need Presented: 5/20/2021
    b. Prior solution meetings: 10/14/2021 (and now 4/20/2023)
    ~~c.~~ New Estimated Projects Costs: $9.75 million ~~$10.5 million~~

d. Projected-in-service date: 12/31/2026
e. Alternatives considered: yes
f. Projected oversight: DE? - No state utility commission regulatory oversight???

Subregional RTEP – Western (April 21, 2023) -

Link:

Needs offered: 40 (AMPT, Com Ed, ATSI, APS, AES-Ohio, Duke, AEP - 20)

Solutions: 17 ($301.36 million)

- **State oversight – 5 ($190.4 million)**
  - DLCO - $100
  - ATSI - $1.1
  - APS – $42.6
  - APS – $45.8
  - AEP – 0.9
- **No state oversight - 10 ($65.25 million)**
  - EKPC - $3.7
  - ATSI - $12.2
  - APS - $5.23
  - APS - $0.3
  - AES – $7.1
  - AES – $0.35
  - Duke (OH) - $3.1
  - AEP – $19.3
  - AEP – $12.48
  - AEP - $1.49

- **Re-solution = 2 w/ no state oversight ($45.71 million)**
  - Re-solution ATSI - $45 million
  - Re-solution AES – DPL $0.71

Total no state oversight

10 solutions ($65.25 million) + 2 re-solutions ($45.71 million) = $110.96 million

DLCO

7. Need Number: DLC-2023-001
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $100 million
    c. Projected-in-service date: 1/1/2026
    d. Alternatives considered: yes
    g. Projected oversight: PA- State utility commission regulatory oversight

EKPC

8. Need Number: EKPC-2023-001
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $3.7 million
    c. Projected-in-service date: 5/1/2023 *under construction
    d. Alternatives considered: *yes
    e. Projected oversight: KY - No state utility commission regulatory oversight
    f. Note: not required per M-3 guidelines – provided for transparency

ATSI

9. Need Number: ATSI-2021-005
    a. Need Presented: 10/15/2021
    b. Estimated Projects Costs: $12.2 million
    c. Projected-in-service date: 6/1/2025
    d. Alternatives considered: no
    e. Projected oversight: PA? - No state utility commission regulatory oversight

10. Need Number: ATSI-2022-023
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $1.1 million
    c. Projected-in-service date: 12/31/2023
    d. Alternatives considered: *No - existing
    e. Projected oversight: OH - State utility commission regulatory oversight

APS-FirstEnergy

11. Need Number: APS-2021-007
    a. Need Presented: 8/16/2021
    b. Estimated Projects Costs: $5.23 million *3 parts
    c. Projected-in-service date: in construction – completed by 4/21/2023
    d. Alternatives considered: No - existing
    e. Projected oversight: WV- No state utility commission regulatory oversight ??? - completed
12. Need Number: APS-2023-003
    a. Need Presented: 2/17/2023
    b. Estimated Projects Costs: $0.3 million
    c. Projected-in-service date: 5/8/2023 *under construction
    d. Alternatives considered: yes

e. Projected oversight: WV - No state utility commission regulatory oversight?? – under construction

13. Need Number: APS-2023-004
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $42.6 million
    c. Projected-in-service date: 12/1/2027
    d. Alternatives considered: yes (somewhat)
    e. Projected oversight: VA - state utility commission regulatory oversight
14. Need Number: APS-2023-005
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $45.8 million
    c. Projected-in-service date: 6/1/2026
    d. Alternatives considered: Yes* greenfield
    e. Projected oversight: VA - state utility commission regulatory oversight

AES-Ohio

15. Need Number: Dayton-2022-006
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $7.1 million
    c. Projected-in-service date: 12/31/2026
    d. Alternatives considered: yes
    e. Projected oversight: OH?- No state utility commission regulatory oversight
16. Need Number: Dayton-2023-001
    a. Need Presented: 2/17/2023
    b. Estimated Projects Costs: $0.35 million
    c. Projected-in-service date: 12/31/2025
    d. Alternatives considered: no
    e. Projected oversight: OH? - No state utility commission regulatory oversight

Duke

17. Need Number: DEOK-2021-007
    a. Need Presented: 6/15/2021
    b. Estimated Projects Costs: $3.1 million
    c. Projected-in-service date: 12/13/2024
    d. Alternatives considered:
    e. Projected oversight: OH - No state utility commission regulatory oversight

AEP

18. Need Number: AEP-2022-AP037
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $0.9 million
    c. Projected-in-service date: None provided

   d. Alternatives considered: no
   e. Projected oversight: OH - State utility commission regulatory oversight

19. Need Number: AEP-2022-IM004
    a. Need Presented: 1/21/2022
    b. Estimated Projects Costs: $19.3 million
    c. Projected-in-service date: 5/7/2027
    d. Alternatives considered: yes
    e. Projected oversight: IN – NO state utility commission regulatory oversight.

20. Need Number: AEP-2022-IM015
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $12.48 million
    c. Projected-in-service date: 8/1/2028
    d. Alternatives considered: yes
    e. Projected oversight: IN - No state utility commission regulatory oversight.

21. Need Number: AEP-2022-OH060
    a. Need Presented: 7/22/2022
    b. Estimated Projects Costs: $1.49 million
    c. Projected-in-service date: 10/1/2024
    d. Alternatives considered: yes
    e. Projected oversight: WV - No state utility commission regulatory oversight.

Re-present solution ATSI

1. Need Number: s1712
   a. Need Presented: 8/31/2018 & solution 9/28/2018
   b. Estimated Projects Costs: $45 million ~~$16 million~~
   c. Projected-in-service date: 12/1/2025
   d. Alternatives considered: yes
   e. Projected oversight: PA?? – No state utility commission regulatory oversight?
2. Need Number: S2695 Dayton-2021-11
   a. Need Presented: 12/17/2021 & solution 2/18/2022
   b. Estimated Projects Costs: $0.71 million ~~$0.31 million~~
   c. Projected-in-service date: 6/30/2026
   d. Alternatives considered: no
   e. Projected oversight: OH - No state utility commission regulatory oversight

Exhibit H: Planning Community Responses

<u>Transmission Owner Projects – presented as part of the April PJM M-3 Process</u>

When: April Subregional meetings
What: Regulatory Public Utility Commission oversight review (e.g. CPCN)
Needs Presented: 49
Solutions Presented: ~~24~~ 23 at an estimated cost of ~~$579.38~~ $476.38 million

- ~~17~~ 16 of these solutions have no state commission oversight (~~$298.78~~ $195.78 million)

Subregional RTEP Committee – Southern (April 20, 2023)

Link: PJM - Meeting Details

Needs: 3 Dominion

Solutions: 0

Subregional RTEP Committee – Mid-Atlantic (April 20, 2023)

Link: PJM - Meeting Details

Needs offered by: 9 (UG1, JCPL, Met-Ed, PPL, and BGE)

Solutions offered: 6 + 1 re-solution [revised 5 +1]

- **No state utility commission oversight = 5 projects $178.25 million**
- **Revised: No state utility commission oversight = 4 projects $75.25 million**
  - **PPL stated in the Planning Community that PPL-2019-0005 need/solution was withdrawn ($103 million)**
- **State utility commission oversight = 1 ($23.96)**

Re-solutions offered: 1 (DPL) $9.57 million

Total no state utility commission oversight = $178.25 + $9.57 = $187.82 million
Revised: Total no state utility commission oversight = $75.25 + $9.57= $84.82 million

Solutions

FirstEnergy (Met-Ed)

1. Need Number: ME-2022-003
   a. Need Presented: 4/19/2022
   b. Estimated Projects Costs: $0.8 million
   c. Alternatives considered: None
   d. Projected-in-service date: 12/29/2023
   e. Projected oversight: PA-No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 9:43 AM

Questions regarding FirstEnergy (Met-Ed) solution Need Number: ME-2022-003: (1) How was the "Estimated Project Cost" of $.8 million developed; (2) please provide a breakdown of the project budget; and (3) Is there state utility commission oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $0.8M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

2. Need Number: ME-2019-044
    a. Need Presented: 7/31/2019
    b. Estimated Projects Costs: $10.3 million
    c. Projected-in-service date: 12/31/2027
    d. Alternatives considered: *Maintain existing condition
    e. Projected oversight: PA?? - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 9:45 AM

Questions re: FirstEnergy (Met-Ed) solution need no: ME-2019-044: (1) How was the "Estimated Project Cost" of $0.3 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $10.3M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

PSEG

3. Need Number: PSEG-2023-0003
    a. Need Presented: 3/16/2023
    b. Estimated Projects Costs: $63 million
    c. Projected-in-service date: 12/2027
    d. Alternatives considered: yes
    e. Projected oversight: NJ - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 9:47 AM

Questions re: PSEG solution need no: PSEG-2023-0003: (1) How was the "Estimated Project Cost" of $63 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Planning Support (PJM Interconnection, LLC)

6 months ago

Response to Question 1: PSE&G develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions, incorporating an appropriate level of contingency to account for risks that are not knowable at the time of estimate development and/or beyond our reasonable control. PSE&G updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Project Status & Cost Allocation page on PJM's website.

Response to Question 2: The project cost of $63M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Project Status & Cost Allocation page on PJM's website.

Response to Question 3: PSE&G will obtain all necessary approvals required by state law.

FirstEnergy (Penelec)

4. Need Number: PN-2023-002
   a. Need Presented: 3/16/20
   b. Estimated Projects Costs: $1.15 million
   c. Projected-in-service date: 5/12/2023
   d. Alternatives considered: no
   e. Projected oversight: PA - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 9:48 AM

Questions re: FirstEnergy(Penelec) solution need no: PN-2023-002: (1) How was the "Estimated Project Cost" of $1.1 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Lawrence Hozempa (FirstEnergy)

6 months ago

Q1- FirstEnergy develops “Estimated Project Costs” provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM’s website.

Q2 - The project cost of $1.15M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM’s website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

5. Need Number: PN-2023-004
    a. Need Presented: 12/14/2022
    b. Estimated Projects Costs: $23.96 million
    c. Projected-in-service date: 4/1/2025
    d. Alternatives considered: yes
    e. Projected oversight: PA - State utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 9:49 AM

Questions re: FirstEnergy(Penelec) solution need no: PN-2023-004: (1) How was the "Estimated Project Cost" of $23.96 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Lawrence Hozempa (FirstEnergy)

6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The PN-2022-004 project cost of $23.96M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

PPL

6. ~~Need Number: PPL-2019-0005~~
    a. ~~Need Presented: 2/22/2019~~
    b. ~~Estimated Projects Costs: $103 million~~
    c. ~~Projected in-service date: 12/30/2028~~
    d. ~~Alternatives considered: yes~~
    e. ~~Projected oversight: PA – No state utility commission regulatory oversight~~

**re-solution (how do we know the original solution was not going forward?)

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 9:51 AM

Questions re: PPL solution need no: PPL-2019-0005: (1) How was the "Estimated Project Cost" of $103 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

pjm Planning Support (PJM Interconnection, LLC)

6 months ago

PPL's Response:

This need number has been cancelled.

1. Need Number: DPL-2021-001
    a. Need Presented: 5/20/2021

b. Prior solution meetings: 10/14/2021 (and now 4/20/2023)
~~c.~~ New Estimated Projects Costs: $9.75 million ~~$10.5 million~~
d. Projected-in-service date: 12/31/2026
e. Alternatives considered: yes
f. Projected oversight: DE? - No state utility commission regulatory oversight???

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 9:53 AM

Questions re: Exelon DPL re-solution need no:DPL-2021-001: (1) How was the "Estimated Project Cost" of $9.75 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Amber Thomas (Customer)
6 months ago

Hi Greg,
1, DPL developed this preliminary cost estimate for this project based on industry-standard cost estimation practices. Since there are uncertainties with this project at this very early planning stage, this cost estimate is preliminary, and updates will be provided through PJM's website at the Transmission Construction Status page as this project progresses along.
2.As previously noted, as the project development progress along, costs are updated through PJM's website at the Transmission Construction Status page
3.Information concerning state utility commission review for transmission projects (including baseline upgrades, network upgrades, and M3 projects) is codified in publicly available state laws. DPL will obtain all pertinent state and/or local approvals as required by law.

Subregional RTEP – Western (April 21, 2023) -

Link:

Needs offered: 40 (AMPT, Com Ed, ATSI, APS, AES-Ohio, Duke, AEP - 20)

Solutions: 17 ($301.36 million)

- **State oversight – 5 ($190.4 million)**
    - DLCO - $100
    - ATSI - $1.1
    - APS – $42.6
    - APS – $45.8
    - AEP – 0.9

- **No state oversight - 10 ($65.25 million)**
    - EKPC - $3.7
    - ATSI - $12.2
    - APS - $5.23
    - APS - $0.3
    - AES – $7.1
    - AES – $0.35
    - Duke (OH) - $3.1
    - AEP – $19.3
    - AEP – $12.48
    - AEP - $1.49

- **Re-solution = 2 w/ no state oversight ($45.71 million)**
    - Re-solution ATSI - $45 million
    - Re-solution AES – DPL $0.71

Total no state oversight

10 solutions ($65.25 million) + 2 re-solutions ($45.71 million) = $110.96 million

DLCO

7. Need Number: DLC-2023-001
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $100 million
    c. Projected-in-service date: 1/1/2026
    d. Alternatives considered: yes
    g. Projected oversight: PA- State utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:07 AM

Questions re: Duquesne Light solution need no:DLC-2023-001: (1) How was the "Estimated Project Cost" of $100 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Planning Support (PJM Interconnection, LLC)

6 months ago

DLC provides the following responses pursuant to Section (c)(7) of Attachment M-3 of the PJM Open Access Transmission Tariff. This section provides that nothing in Attachment M-3 precludes any Transmission Owner from agreeing to provide additional meetings or other communications regarding Attachment M-3 Projects, in addition to the information required pursuant to Attachment M-3.

1. How was the "Estimated Project Cost" of $100 million developed?
• DLC develops early-stage cost estimates for the M-3 process in accordance with standard industry cost estimation practices based on scope of work assumptions. DLC also incorporates a contingency to account for uncertainties. DLC regularly updates project costs throughout the project development and those costs are posted publicly on the PJM Project Status & Cost Allocation page on pjm.com.
2. Please provide a breakdown of this project budget.
• The early-stage cost estimate is initial and will be regularly updated throughout the project development and those costs will be posted publicly on the PJM Project Status & Cost Allocation page on pjm.com.
3. Does a state utility commission have oversight?
• DLC will obtain all necessary approvals. Information on Pennsylvania regulatory requirements for transmission projects is publicly available.

EKPC

8. Need Number: EKPC-2023-001
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $3.7 million
    c. Projected-in-service date: 5/1/2023 *under construction
    d. Alternatives considered: *yes
    e. Projected oversight: KY - No state utility commission regulatory oversight
    f. Note: not required per M-3 guidelines – provided for transparency

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 10:08 AM

Questions re: EKPC solution need no: EKPC-2023-001: (1) How was the "Estimated Project Cost" of $3.7 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Planning Support (PJM Interconnection, LLC)
6 months ago

1. The estimated project costs EKPC provides as part of solutions presentations are preliminary in nature and are based on the initial scope identified for the project. These estimates are generally based on past actual costs of projects that are similar in nature and have not been refined at this point based on a more detailed engineering effort. EKPC includes appropriate levels of contingency in these estimates to account for the very early nature of these estimates, as well as uncertainties typically applicable to each specific type of transmission projects. EKPC continues to update and refine these cost estimates as projects progress beyond the initial stage, and these updated estimates are provided to PJM for posting on its Project Status & Cost Allocation page.

2. The estimated project cost presented is an early "planning-level" estimate based on the initially-identified scope and historical costs of EKPC projects of similar scope. This cost estimate has not yet been vetted through EKPC's detailed engineering estimating process, therefore breakdown of the estimate in a more granular fashion is not available at this stage in the project life-cycle. EKPC will continue to update and refine this cost estimate as the project progresses beyond the initial stage, and this updated estimate will be provided to PJM for posting on its Project Status & Cost Allocation page.

3. EKPC will ensure that all necessary approvals required by Kentucky law are secured for the project. The approval requirements for utility projects in the Commonwealth of Kentucky are publicly available via the Kentucky Public Service Commission website.

Like · Select as Best

ATSI

9. Need Number: ATSI-2021-005
    a. Need Presented: 10/15/2021
    b. Estimated Projects Costs: $12.2 million
    c. Projected-in-service date: 6/1/2025
    d. Alternatives considered: no
    e. Projected oversight: PA? - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:15 AM

Questions re: ATSI solution need no :ATSI-2021-005: (1) How was the "Estimated Project Cost" of $12.2 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $12.2M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

10. Need Number: ATSI-2022-023
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $1.1 million
    c. Projected-in-service date: 12/31/2023
    d. Alternatives considered: *No - existing
    e. Projected oversight: OH - State utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:19 AM

Questions re: FirstEnergy (ATSI) solution need no:S1712: (1) How was the "Estimated Project Cost" of $45 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $45M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

APS-FirstEnergy

11. Need Number: APS-2021-007
    a. Need Presented: 8/16/2021
    b. Estimated Projects Costs: $5.23 million *3 parts
    c. Projected-in-service date: in construction – completed by 4/21/2023
    d. Alternatives considered: No - existing
    e. Projected oversight: WV- No state utility commission regulatory oversight ??? – Completed

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:24 AM

Questions re: FirstEnergy(APS)solution needs no:APS-2021-007 through 009: (1) How was the "Estimated Cost" of $5.33 million developed; (2) Please provide a further breakdown of these project budgets; and (3) Does a state utility commission have oversight?

Lawrence Hozempa (FirstEnergy)

6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $1.10M for APS-2021-007, $2.08M for APS-2021-008, and $2.15M for APS-2021-009 presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

12. Need Number: APS-2023-003
    a. Need Presented: 2/17/2023
    b. Estimated Projects Costs: $0.3 million
    c. Projected-in-service date: 5/8/2023 *under construction
    d. Alternatives considered: yes
    e. Projected oversight: WV - No state utility commission regulatory oversight?? – under construction

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 10:25 AM

Questions re: FirstEnergy (APS) solution need no:APS-2023-003: (1) How was the "Estimated Project Cost" of $0.3 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Lawrence Hozempa (FirstEnergy)

6 months ago

Q1- FirstEnergy develops “Estimated Project Costs” provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM’s website.

Q2 - The project cost of $0.3M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM’s website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

13. Need Number: APS-2023-004
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $42.6 million
    c. Projected-in-service date: 12/1/2027
    d. Alternatives considered: yes (somewhat)
    e. Projected oversight: VA - state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 10:27 AM

Questions re: FirstEnergy(APS) solution need no: APS-2023-004: (1) How was the "Estimated Project Cost" of $42.6 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops “Estimated Project Costs” provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM’s website.

Q2 - The project cost of $42.6M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM’s website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

Like · Select as Best

14. Need Number: APS-2023-005
    a. Need Presented: 3/17/2023
    b. Estimated Projects Costs: $45.8 million
    c. Projected-in-service date: 6/1/2026
    d. Alternatives considered: Yes* greenfield
    e. Projected oversight: VA - state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:28 AM

Questions re: FirstEnergy (APS) solution need no: APS-2023-005: (1) How was the "Estimated Project Cost" of $45.8 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops "Estimated Project Costs" provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM's website.

Q2 - The project cost of $45.8M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

AES-Ohio

15. Need Number: Dayton-2022-006
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $7.1 million
    c. Projected-in-service date: 12/31/2026
    d. Alternatives considered: yes
    e. Projected oversight: OH?- No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:39 AM

Questions re: DP&L AES-Ohio solution need no: Dayton-2022-006: (1) How was the "Total Estimated Transmission Cost" of $7.1 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

SRRTEP

pjm Planning Support (PJM Interconnection, LLC)
6 months ago

1. (1) How was the "Total Estimated Transmission Cost" of $7.1 million developed; - AES Ohio developed the Estimated Project Cost in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature based on the initial conceptual engineering review of the proposed project, which includes incorporating an appropriate level of contingency to account for uncertainties and unpredictability. AES Ohio will update the cost estimates through the PJM Transmission Construction Status page on PJM's website as the project progresses.
    1. (2) Please provide a breakdown of this project budget; The project cost of $7.1M presented is an early-stage conceptual engineering estimate. As work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.
    2. (3) Does a state utility commission have planning oversight? Information concerning the state utility commission review of Attachment M-3 Projects is codified in state law and publicly available. AES Ohio will obtain all necessary approvals required by state law.

16. Need Number: Dayton-2023-001
    a. Need Presented: 2/17/2023
    b. Estimated Projects Costs: $0.35 million
    c. Projected-in-service date: 12/31/2025
    d. Alternatives considered: no
    e. Projected oversight: OH? - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:41 AM

Questions re: DP&L AES-Ohio solution need no: Dayton-2023-001: (1) How was the "Total Estimated Cost" of $350 thousand developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

SRRTEP

pjm Planning Support (PJM Interconnection, LLC)
6 months ago

1. (1) How was the "Total Estimated Cost" of $350 thousand developed; - AES Ohio developed the Estimated Project Cost in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature based on the initial conceptual engineering review of the proposed project, which includes incorporating an appropriate level of contingency to account for uncertainties and unpredictability. AES Ohio will update the cost estimates through the PJM Transmission Construction Status page on PJM's website as the project progresses.
    1. (2) Please provide a breakdown of this project budget; The project cost of $350k presented is an early-stage conceptual engineering estimate. As work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.
    2. (3) Does a state utility commission have planning oversight? Information concerning the state utility commission review of Attachment M-3 Projects is codified in state law and publicly available. AES Ohio will obtain all necessary approvals required by state law.

Duke

17. Need Number: DEOK-2021-007
    a. Need Presented: 6/15/2021
    b. Estimated Projects Costs: $3.1 million
    c. Projected-in-service date: 12/13/2024
    d. Alternatives considered:
    e. Projected oversight: OH - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:12 AM

Questions re: DEOK solution need no:DEOK-2021-007: (1) How was the "Estimated Transmission Cost" of $3.1 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

Planning Support (PJM Interconnection, LLC)
Edited April 18, 2023 at 1:54 PM

DEOK responds as follows:

(1) The estimate was developed in accordance with the recommend practices endorsed by the Association for the Advancement of Cost Engineering. This Class 4 estimate is comprised of only transmission costs. No distribution costs are included.
(2) This question does not address the proposed transmission plan and falls outside the bounds of Attachment M-3 to the Tariff. Historic transmission costs specific to Duke Energy Ohio are publicly available.
(3) This question does not address the proposed transmission plan and falls outside the bounds of Attachment M-3 to the Tariff. Information on oversight of transmission projects in Ohio is publicly available.

Like · Select as Best

AEP

18. Need Number: AEP-2022-AP037
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $0.9 million
    c. Projected-in-service date: None provided
    d. Alternatives considered: no
    e. Projected oversight: OH - State utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:30 AM

Questions re: AEP solution need no: AEP-2022-AP037: (1) How was the "Total Estimated Transmission Cost" of $0.9 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Planning Support (PJM Interconnection, LLC)

6 months ago

(1) How was the "Total Estimated Transmission Cost" of [$$$] developed?

AEP develops “Total Estimated Transmission Costs” provided in project solutions meeting presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature, based on the initial scope of work assumptions, and incorporate an appropriate level of contingency to account for uncertainties and unpredictability. AEP updates these cost estimates as project development progresses, and such updated costs are provided through the Project Status & Cost Allocation page on the PJM website.

(2) Please provide a breakdown of this project budget.

The presented project cost is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the Project Status & Cost Allocation page on the PJM website.

(3) Does a state utility commission have planning oversight?

Information concerning state utility commission review of individual Attachment M-3 Projects is reflected in state law, which is publicly available. AEP will obtain all necessary approvals required by state law.

Like · Select as Best

19. Need Number: AEP-2022-IM004
    a. Need Presented: 1/21/2022
    b. Estimated Projects Costs: $19.3 million
    c. Projected-in-service date: 5/7/2027
    d. Alternatives considered: yes
    e. Projected oversight: IN – NO state utility commission regulatory oversight.

Questions re: AEP solution need no: AEP-2022-IM004: (1) How was the "Total Estimated Transmission Cost" of $19.3 million developed; (2) Please provide a further breakdown of this project budget; and (3) Does a state utility commission have oversight?

pjm Planning Support (PJM Interconnection, LLC)

6 months ago

(1) How was the "Total Estimated Transmission Cost" of [$$$] developed?

AEP develops "Total Estimated Transmission Costs" provided in project solutions meeting presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature, based on the initial scope of work assumptions, and incorporate an appropriate level of contingency to account for uncertainties and unpredictability. AEP updates these cost estimates as project development progresses, and such updated costs are provided through the Project Status & Cost Allocation page on the PJM website.

(2) Please provide a breakdown of this project budget.

The presented project cost is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the Project Status & Cost Allocation page on the PJM website.

(3) Does a state utility commission have planning oversight?

Information concerning state utility commission review of individual Attachment M-3 Projects is reflected in state law, which is publicly available. AEP will obtain all necessary approvals required by state law.

20. Need Number: AEP-2022-IM015
    a. Need Presented: 9/16/2022
    b. Estimated Projects Costs: $12.48 million
    c. Projected-in-service date: 8/1/2028
    d. Alternatives considered: yes
    e. Projected oversight: IN - No state utility commission regulatory oversight.

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.

April 14, 2023 at 10:33 AM

Questions re: AEP solution need no: AEP-2022-IM015: (1) How was the "Total Estimated Transmission Cost" of $12.48 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Planning Support (PJM Interconnection, LLC)

6 months ago

(1) How was the "Total Estimated Transmission Cost" of [$$$] developed?

AEP develops "Total Estimated Transmission Costs" provided in project solutions meeting presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature, based on the initial scope of work assumptions, and incorporate an appropriate level of contingency to account for uncertainties and unpredictability. AEP updates these cost estimates as project development progresses, and such updated costs are provided through the Project Status & Cost Allocation page on the PJM website.

(2) Please provide a breakdown of this project budget.

The presented project cost is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the Project Status & Cost Allocation page on the PJM website.

(3) Does a state utility commission have planning oversight?

Information concerning state utility commission review of individual Attachment M-3 Projects is reflected in state law, which is publicly available. AEP will obtain all necessary approvals required by state law.

Like · Select as Best

21. Need Number: AEP-2022-OH060
    a. Need Presented: 7/22/2022
    b. Estimated Projects Costs: $1.49 million
    c. Projected-in-service date: 10/1/2024
    d. Alternatives considered: yes
    e. Projected oversight: WV - No state utility commission regulatory oversight.

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:35 AM

Questions re: solution need no: AEP-2022-OH060: (1) How was the "Total Estimated Transmission Cost" of $1.49 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

pjm Planning Support (PJM Interconnection, LLC)
6 months ago

(1) How was the "Total Estimated Transmission Cost" of [$$$] developed?

AEP develops "Total Estimated Transmission Costs" provided in project solutions meeting presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature, based on the initial scope of work assumptions, and incorporate an appropriate level of contingency to account for uncertainties and unpredictability. AEP updates these cost estimates as project development progresses, and such updated costs are provided through the Project Status & Cost Allocation page on the PJM website.

(2) Please provide a breakdown of this project budget.

The presented project cost is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the Project Status & Cost Allocation page on the PJM website.

(3) Does a state utility commission have planning oversight?

Information concerning state utility commission review of individual Attachment M-3 Projects is reflected in state law, which is publicly available. AEP will obtain all necessary approvals required by state law.

Like · Select as Best

Re-present solution ATSI

1. Need Number: s1712
   a. Need Presented: 8/31/2018 & solution 9/28/2018
   b. Estimated Projects Costs: $45 million ~~$16 million~~
   c. Projected-in-service date: 12/1/2025
   d. Alternatives considered: yes

e. Projected oversight: PA?? – No state utility commission regulatory oversight?

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:19 AM

Questions re: FirstEnergy (ATSI) solution need no:S1712: (1) How was the "Estimated Project Cost" of $45 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have planning oversight?

Lawrence Hozempa (FirstEnergy)
6 months ago

Q1- FirstEnergy develops “Estimated Project Costs” provided in project solutions presentations in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature and based on the initial scope of work assumptions. FirstEnergy updates its cost estimates as project development progresses, and such updated costs are provided through the PJM Transmission Construction Status page on PJM’s website.

Q2 - The project cost of $45M presented is an early-stage engineering estimate. As more analysis is performed and project development work progresses, costs are updated through the PJM Transmission Construction Status page on PJM’s website.

Q3 - Information concerning state utility commission review of Attachment M-3 Projects is codified in state law and is publicly available. FirstEnergy will obtain all necessary approvals required by state law.

2. Need Number: S2695 Dayton-2021-11
   a. Need Presented: 12/17/2021 & solution 2/18/2022
   b. Estimated Projects Costs: $0.71 million ~~$0.31 million~~
   c. Projected-in-service date: 6/30/2026
   d. Alternatives considered: no
   e. Projected oversight: OH - No state utility commission regulatory oversight

Greg Poulos (Consumer Advocates of the PJM States (CAPS)) asked a question.
April 14, 2023 at 10:14 AM

Questions re: DP&L (AES Ohio) re-solution need no: Dayton-2021-011: (1) How was the "Estimate Cost" of $0.71 million developed; (2) Please provide a breakdown of this project budget; and (3) Does a state utility commission have oversight?

pjm Planning Support (PJM Interconnection, LLC)
6 months ago

1. (1) How was the "Estimate Cost" of $0.71 million developed- AES Ohio developed the Estimated Project Cost in accordance with industry-standard cost estimation practices. These estimates are preliminary in nature based on the initial conceptual engineering review of the proposed project, which includes incorporating an appropriate level of contingency to account for uncertainties and unpredictability. AES Ohio will update the cost estimates through the PJM Transmission Construction Status page on PJM's website as the project progresses.
    1. (2) Please provide a breakdown of this project budget; The project cost of $.71M presented is an early-stage conceptual engineering estimate. As work progresses, costs are updated through the PJM Transmission Construction Status page on PJM's website.
    2. (3) Does a state utility commission have planning oversight? Information concerning the state utility commission review of Attachment M-3 Projects is codified in state law and publicly available. AES Ohio will obtain all necessary approvals required by state law.