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October 28, 2022

VIA THE COMMISSION'S ELECTRONIC TARIFF FILING SYSTEM

Linda C. Bridwell
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40601-0615

RE: **Kentucky Power Company – Special Contract For Electric Service And Rider D.R.S. Addendum With Ebon International, LLC**

Dear Ms. Bridwell:

Please accept for electronic filing the Contract for Firm Electric Service ("Contract") between Kentucky Power Company ("Kentucky Power" or the "Company") and Ebon International, LLC ("Ebon"). The Company is filing herewith the Contract and supporting documents as follows:

1) Public redacted version of Testimony of Brian K. West in support of the Contract ("West Testimony"), which includes:

a) Public redacted version of the Contract

b) Marginal cost study; and

2) Kentucky Power Company's Request for Confidential Treatment.[1]

The Contract provides for electric service to serve Ebon's facility to be located at 23250 US Highway 23, Louisa, Kentucky, in Lawrence County (the "Ebon Facility"), on a portion of the site of the Company's Big Sandy Generating Station. Ebon will invest over $250 million in order to develop and construct the Ebon Facility at the site. The contract capacity for the Ebon Facility is planned for 250 MW in Phase Two but will have an initial contract capacity of approximately 80 MW to 100 MW in Phase One. Among the services that the Ebon Facility will provide are the mining of cryptocurrencies, such as Bitcoin and Ethereum, as well as blockchain and data

[1] The Company will provide by separate email to the Executive Director the confidential version of the West Testimony, including the confidential version of the Contract.

processing services to be procured by other businesses in support of artificial intelligence, Fintech, and other industrial computer applications.

The Contract, Exhibit 1 to the Contract, and portions of the Testimony of Brian K. West each contain confidential pricing information. The Company also is submitting herewith a Motion for Confidential Treatment of that information.

Additional information supporting the request for approval of the Contract, the terms of the special contract, and the Company's request for confidential treatment of certain pricing information is contained in the Testimony of Brian K. West.

Kentucky Power respectfully requests that the Commission accept and approve the Contract based upon the information and documentation transmitted with this letter.

Please contact me should you have any questions

Very truly yours,

STITES & HARBISON PLLC

Katie M. Glass

KMG
Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: TFS2022-00_____

Kentucky Power Company's Motion
For Confidential Treatment

Kentucky Power Company ("Kentucky Power" or "Company") moves the Public Service Commission of Kentucky ("Commission") pursuant to 807 KAR 5:001, Section 13(2), 807 KAR 5:011, Section 14, and KRS 61.878(1)(c) for an Order granting confidential treatment to:

1) Article 5.1(A) through Article 5.1(H) of the Special Contract for Electric Service dated August 23, 2022, between the Company and Ebon International, LLC ("Ebon") ("Special Contract");

2) The entirety of Confidential Exhibit 1 to the Special Contract ("Exhibit 1"); and

3) The identified portions of the Direct Testimony of Company Witness Brian K. West in support of the Special Contract ("West Testimony").

Specifically, the information identified above contains the confidential pricing information the Company negotiated with Ebon.

Further, pursuant to 807 KAR 5:001, Section 13, Kentucky Power requests that the Commission file under seal the entirety of Exhibit 1, and those portions of the Special Contract and the West Testimony containing confidential information with the confidential portions highlighted in yellow. Kentucky Power will notify the Commission in the future if the Company determines the information for which confidential treatment is sought is no longer confidential prior to the end of the period for which confidential treatment is requested herein.

A. The Confidential Information and the Statutory Standard.

Kentucky Power does not object to filing the identified information for which it is seeking confidential treatment, but it requests that the entirety of Exhibit 1, and the identified portions of the Special Contract and the West Testimony be excluded from the public record and public disclosure.

KRS 61.878(1) excludes from the Open Records Act:

> (c) (1) Upon and after July 15, 1992, records confidentially disclosed to an agency or required to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records.

This exception applies to the information for which Kentucky Power is seeking confidential treatment herein.

B. The Special Contract, Exhibit 1, and the West Testimony.

Kentucky Power is filing the Special Contract between the Company and Ebon entered into on August 23, 2022, Exhibit 1 to the Special Contract, and the West Testimony. Each of these documents, either in whole or in part, contain confidential pricing information negotiated by the Company with its potential future customer, Ebon.

As further supported by the West Testimony at pages 13-16, both Kentucky Power and Ebon seek confidential treatment of the information identified herein. Whether mining cryptocurrencies or providing data processing services to other high-tech business described above, Ebon operates in a highly competitive industry in which cost information is highly protected for competitive advantage. The cryptocurrency mining and data services industry is driven by access to power with the cost of electric power accounting for over 90 percent of the operational costs of providing such services.[1] Consequently, Ebon seeks to maintain confidentiality regarding the cost of power it obtains from Kentucky Power under the Special Contract. Similar to other industrial customers (steel, aluminum, pulp and paper), Ebon needs to maintain confidentiality regarding the cost of the commodities and services it competes to sell. Ebon will suffer injury by any public release of the confidential portions of the Special Contract because its competitors will gain access to the most sensitive information regarding its cost of operations.

Moreover, the identified confidential information reflects the confidential strategy Kentucky Power used to negotiate the Special Contract and design its rates. The disclosure of such information would jeopardize the Company's ability to fairly negotiate future special contracts. Making the negotiated rates public would establish a ceiling for future rates negotiated with other similar customers looking to locate in Kentucky Power's service territory, or potentially for existing customers asking to establish new rates through special contracts. Common sense and experience teach that future prospects will demand rates that meet or are less than the Ebon rates. Kentucky Power might be faced with meeting or beating the rates in the Special Contract or risk losing the prospective new business. In addition, existing customers also could seek similar rates with respect to both existing and any expanded load. This means that the confidential rate information cannot be disclosed to existing customers or to the more general public.

The confidential information identified in the Special Contract, Exhibit 1, and the West Testimony should be kept confidential for the entire term of the Special Contract, including any

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[1] *See* https://www.reuters.com/article/us-markets-bitcoin-mining-idUSKCN0ZO2CW (last accessed September 19, 2022).

extensions of the contract term. After such time there will no longer be any competitive advantage to be gained from the information.

C. The Identified Information is Generally Recognized as Confidential and Proprietary and Public Disclosure of it Will Result in an Unfair Commercial Advantage for Kentucky Power's Competitors.

The identified information required to be disclosed by Kentucky Power in the Special Contract, Exhibit 1, and the West Testimony is highly confidential. Dissemination of the the identified information is restricted by Kentucky Power, its parent, American Electric Power Company, Inc. ("AEP"), and American Electric Power Service Corporation ("AEPSC"). The Company, AEP, and AEPSC take all reasonable measures to prevent its disclosure to the public as well as to persons within the Company and third-party vendors who do not have a need for the information. Within those organizations, the information is available only upon a confidential need-to-know basis that does not extend beyond those employees with a legitimate business need to know and act upon the identified information.

It is my understanding that Ebon also maintains the identified confidential information as confidential and protects it from disclosure.

D. The Identified Information is Required to be Disclosed to an Agency.

The identified information is being filed in accordance with 807 KAR 5:011, Section 13. The Commission is a "public agency" as that term is defined in KRS 61.870(1). Any filing should be subject to a confidentiality order and any party requesting such information should be required to enter into an appropriate confidentiality agreement.

WHEREFORE, Kentucky Power Company respectfully requests the Commission to enter an Order:

1. According confidential status to and withholding from public inspection:

(a) The identified portions (Article 5.1(A) through Article 5.1(H)) of the Special Contract;

(b) The entirety of Confidential Exhibit 1 to the Special Contract; and

(c) The identified portions of the Testimony of Company Witness Brian K. West; and

2. Granting Kentucky Power all further relief to which it may be entitled.

Respectfully submitted,

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

IN SUPPORT OF A CONTRACT

FOR ELECTRIC SERVICE WITH EBON INTERNATIONAL, LLC

DIRECT TESTIMONY OF
BRIAN K. WEST
ON BEHALF OF KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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DIRECT TESTIMONY OF
BRIAN K. WEST
ON BEHALF OF KENTUCKY POWER COMPANY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brian K. West. My position is Vice President, Regulatory & Finance for Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an Associate's degree in Applied Science (Electronics Technology) and a Bachelor's degree in Business Management, both from Ohio University, in 1987 and 1988, respectively. I obtained a Master of Business Administration degree from Ohio Dominican University in 2008.

I began my utility industry career when I joined Ohio Power Company as a customer services assistant in Portsmouth, Ohio in 1989. This was a supervisor-in-training position, where I worked in each area of the office (*e.g.,* cashiering, new service, and credit and collections) to gain knowledge and experience with every aspect of managing an area office. After completing the training program, I initially supervised meter readers in the Portsmouth office until being promoted to office supervisor in 1993. In 1997, when the area offices closed, I transferred to Chillicothe, Ohio and accepted the position of customer services field supervisor, with responsibility for managing customer field representatives who primarily worked with customers on high-bill and other inquiries.

In 2000, after American Electric Power Company ("AEP") merged with Central and South West Corporation, I moved to Columbus, Ohio, where I held various positions in Customer Operations, mostly in process improvement and supporting regulatory filings. In 2008, I transferred to AEP's Regulatory Services department, where I supported various filings before public service commissions in Arkansas, Indiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, as well as the Public Service Commission of Kentucky ("Commission").

In 2010, I was promoted to regulatory case manager, with responsibility for energy efficiency/demand response filings, integrated resource plan filings, and various renewable filings across AEP's service territory. In 2016, I moved to a case manager role with primary responsibility for most Appalachian Power Company filings before the Public Service Commission of West Virginia, the Virginia State Corporation Commission, and the Tennessee Public Utility Commission. I accepted the position of Director of Regulatory Services for Kentucky Power in February 2019. I assumed my current position as Vice President, Regulatory & Finance for Kentucky Power Company in January 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, REGULATORY & FINANCE FOR KENTUCKY POWER?

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This includes planning and executing rate filings for both federal and state regulatory agencies, as well as filings for certificates of public convenience and necessity before this Commission. I am also responsible for managing the Company's financial operating plans. Included as part of this responsibility is the preparation and coordination of various capital and operation and maintenance ("O&M") budgets to ensure that adequate resources such as debt, equity, and cash are available to build, operate, and maintain Kentucky Power's electric system assets used to provide service to the Company's retail and wholesale customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony in support of Kentucky Power's regulatory filings since 2019. Most germane to my testimony in this case, I filed testimony in Case No. 2020-00019, an application for approval of a special contract with Air Products and Chemicals, Inc.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying in support of Kentucky Power's application for approval by the Public Service Commission of Kentucky ("KPSC" or the "Commission") of the Special Contract between the Company and Ebon International, LLC ("Ebon" or the "Customer") for Ebon's facility to be located at 23250 US Highway 23, Louisa, Kentucky, in Lawrence County (the "Ebon Facility"). My testimony explains why the Special Contract is necessary to support economic stability and development in the Company's service territory; it further demonstrates that the Special Contract will provide benefits to the Company's other customers and the Commonwealth. I also provide an overview of some of the details of the Special Contract and support the Company's request for confidential treatment of certain aspects of the Special Contract in this proceeding.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

BKW-Exhibit 1: Special Contract (Public Version)

BKW-Exhibit 2: Marginal Cost Analysis

IV. ECONOMIC SITUATION IN THE COMPANY'S SERVICE TERRITORY

Q. PLEASE DESCRIBE THE ECONOMIC HEALTH OF THE COMPANY'S SERVICE TERRITORY.

A. The Company's service territory is located in eastern Kentucky. This area has been heavily impacted by the more than a decade-long precipitous decline of the coal industry across the Commonwealth, as well as the decline of large industrial operations in Kentucky Power's service territory. The large industrial operations in Kentucky Power's service territory that have reduced or shuttered their operations include the AK Steel Ashland facility, and Ashland-based Our Lady of Bellefonte Hospital, which closed in September 2020. Both closures resulted in the loss of important employment in the area. Most recently, Steel Dynamics announced a joint venture with Unity Aluminum, Inc. (formerly Braidy Industries, Inc.) to construct a $1.9 billion aluminum rolling mill in an unnamed state in the southeastern United States. A Unity spokesperson further stated that the planned site for the mill near Ashland in the Company's service territory was not large enough for the proposed project, possibly dealing yet another blow to the Company and its customers in eastern Kentucky. Kentucky Power's customers and companies with operations in the Company's service territory face unique and difficult challenges as a result of the economic environment in the area.

Q. PLEASE DESCRIBE EBON AND ITS BUSINESS.

A. Ebon is the wholly-owned subsidiary of Ebang International Holdings Inc., ("Ebang") a publicly-listed company (NASDAQ: EBON) in the United States focused on the development, deployment, and management of telecommunication and blockchain technology. Ebang was founded in 2010, and engages in the R&D, production, sales and servicing of telecommunications high-tech equipment and services. In addition, Ebang has expanded into the emerging blockchain technology industry with three main segments of operation:

1. Ebang designs proprietary Application-Specific Integrated Circuit (ASIC) chips. These integrated circuits are customized computer chips targeted for increased efficiency in particular computing processes.
2. Ebang manufactures specific computing hardware equipment, utilizing its own in-house ASIC chips, that are used in data centers and support underlying technology applications including telecommunications, blockchain & data processing, artificial intelligence (AI), Fintech, and other industrial computer applications.
3. Ebang owns and operates its own government-regulated blockchain based cryptocurrency exchange platform, which provides a secure forum for international computing transactions.

Q. PLEASE DESCRIBE THE EBON FACILITY, ALONG WITH ITS OPERATIONS, THAT ARE THE SUBJECT OF THE PROPOSED SPECIAL CONTRACT.

A. Ebon proposes to develop, finance, construct, and operate a blockchain data computing complex in Lawrence County, Kentucky, using its proprietary technologies to provide complex network, computational, and storage services. The Ebon Facility will be located at 23250 US Highway 23, Louisa, Kentucky, on a portion of the site of the Company's Big Sandy Generating Station. The Ebon Facility will be located on an approximately 55-acre site to be leased from Kentucky Power. Ebon will invest over $250 million in order to develop and construct the Ebon Facility at the site. The contract capacity for the Ebon Facility is planned for 250 MW in Phase Two but will have an initial contract capacity of approximately 80 MW to 100 MW in Phase One. Among the services that the Ebon Facility will provide are the mining of cryptocurrencies, such as Bitcoin and Ethereum, as well as blockchain and data processing services to be procured by other businesses in support of artificial intelligence, Fintech, and other industrial computer applications.

Q. WHY IS EBON INTERESTED IN DEVELOPING THE EBON FACILITY IN THE COMPANY'S SERVICE TERRITORY?

A. It is my understanding that Ebon has been searching throughout the United States for stable infrastructure in a business-friendly economic situation. Beyond the capital cost of developing the Ebon Facility, the cost of power and predictability of its supply are key criteria for locating its facility. In addition, as explained below, Ebon is looking for good employees to operate the Ebon Facility. The Company has worked with Ebon to recognize its service territory as a great place to invest and build its facility.

Q. WILL THE SPECIAL CONTRACT HELP ADDRESS ECONOMIC HARDSHIPS IN THE COMPANY'S SERVICE TERRITORY?

A. Yes, the Special Contract sets rates and terms that will enable Ebon to locate in the Company's service territory and bring needed load and jobs to the area. Ebon has confirmed that it would not locate in Kentucky Power's service territory absent the proposed rates and terms. The decline in the Company's load over the past decade has placed upward pressure on rates by requiring that the Company's fixed costs be spread over a declining number of customers and load. New or increased load, such as would be facilitated under the Special Contract, would allow the Company's fixed costs to be spread over a larger load.

Q. THE ROCKPORT UNIT POWER AGREEMENT ("UPA") EXPIRES DECEMBER 7, 2022. WILL KENTUCKY POWER HAVE SUFFICIENT CAPACITY TO SERVE ITS EXISTING CUSTOMERS FOLLOWING THE EXPIRATION OF THE ROCKPORT UPA?

A. No. Kentucky Power projects it will be required to acquire 152.4 MW of capacity for the 2022/2023 PJM Planning Year and 70.2 MW for the 2023/2024 PJM Planning Year. The Company plans in the short term to obtain the replacement capacity required to serve the Company's customers through and under the terms and conditions of the Power Coordination Bridge Agreement ("Bridge PCA") between Kentucky Power and the AEP Operating Companies. The capacity for the 2022/2023 PJM Planning Year will be priced at the Base Residual Auction Clearing Price for that planning year of $50 per MW-day. The capacity for the 2023/2024 PJM Planning Year will be priced at the Base Residual Auction Clearing Price for that planning year of $34.13 per MW-day. Purchased capacity will be less costly than that currently provided under the Rockport UPA.

Q. WHAT IS KENTUCKY POWER'S PLAN TO ACQUIRE CAPACITY TO SERVE THE EBON FACILITY?

A. Kentucky Power will acquire the capacity to serve the Ebon Facility through the Bridge PCA. That capacity will be priced and provided at the same price and conditions as the capacity acquired to serve the Company's existing customers.

Q. WILL KENTUCKY POWER BE REQUIRED TO ACQUIRE 250 MW OF ADDITIONAL CAPACITY TO SERVE THE EBON FACILITY?

A. No. Ebon has designated 10 percent of its Total Capacity Reservation as Firm Capacity beginning in year one of the Special Contract, while the remaining 90 percent of its load remains interruptible under Rider D.R.S. (Demand Response Service). Thus, of Ebon's Total Capacity Reservation of 250 MW, Kentucky Power will be required to acquire only 25 MW to meet the Company's PJM capacity requirements.

Q. ARE THE SPECIAL CONTRACT RATES SUFFICIENT TO COVER ALL MARGINAL COSTS ASSOCIATED WITH EBON'S PROPOSED LOAD AND TO CONTRIBUTE TO FIXED COSTS?

A. Yes. **BKW-EXHIBIT 2** demonstrates that the Special Contract rates designed will recover all marginal costs and will contribute to fixed costs that otherwise would have to be borne by other customers. The marginal cost analysis includes costs for energy, distribution and transmission.

Q. WHY DOES EXHIBIT BKW-2 NOT INCLUDE GENERATION COSTS?

A. The Company will not incur any additional incremental costs to purchase capacity otherwise provided by Rockport through at least May 31, 2024.

Kentucky Power has an obligation to supply generation capacity to cover all of its load, regardless of the load's composition. The Company cannot unreasonably discriminate against one customer over another based on what type of business they are in, its business model, or its number of employees. The Company cannot unreasonably discriminate, period.[1]

Kentucky Power's internal load varies each day with the weather and the operations of its customers. New industrial load with high load factors, such as that provided through cryptocurrency operations, makes more efficient use of capacity resources than variable existing load. Moreover, load varies constantly on an hour-by-hour basis and could be attributed to the operations of existing customers as well as to new customers. The cost of capacity needed to serve new load has never been directly assigned only to new customers. Purchased power or costs to construct a new generation station benefits all customers when the fixed costs are distributed over the increased load. This would be reflected in the cost of service submitted as part of a base rate case filing.

With regard to energy, Kentucky Power sells all of its available generation on a daily basis into the PJM market and then purchases the energy it needs to serve its customers. This process happens regardless of customer load and available generation with all customers paying tariff rates approved by the Commission for the kWh they use. No additional costs attributable to new load are passed on to other customers.

Finally, by agreeing to drop 90 percent of its load when called upon to do so, Ebon will be helping the Company to shave its coincident peaks in PJM and avoid the need for additional capacity, a cost savings that would be passed on to all customers.

[1] Another point to consider is that absent new load, including residential, commercial and industrial customers, when the Rockport UPA expires, the cost of any capacity purchases to serve native load would be borne by all customers.

Q. CAN YOU DESCRIBE THE TYPES OF POSITIONS EBON WILL HIRE TO OPERATE ITS FACILITY?

A. Yes. The highly technical nature of Ebon's operations will necessitate hiring and maintaining approximately 100 positions including project managers, business development managers, electrical engineers, network engineers, facility maintenance engineers and technicians as well as human resources, finance, general maintenance workers and security guards. The majority of these positions are for the most part very technical professional positions ranging in annual compensation from approximately $44,000 to approximately $76,000. These jobs are needed in an area suffering from the loss of industry and opportunities. These jobs will be significant for Louisa, Kentucky, where the median household income in 2020 was $29,167.[2] Therefore, the establishment of Ebon's operations in Lawrence County will help stabilize the economy in that part of the Company's service territory.

V. SPECIAL CONTRACT OVERVIEW

Q. PLEASE DESCRIBE THE SPECIAL CONTRACT.

A. The Special Contract sets Ebon's Total Capacity Reservation when Phase Two has been reached at 250 MW with 25 MW of its Total Capacity Reservation designated as its Firm Service Capacity Reservation. Should the Company call for a discretionary interruption event under Rider D.R.S., Ebon will interrupt its operations and shed 90 percent of its load.

Q. [redacted]

A. [redacted]

Q. EXPLAIN WHY EBON CANNOT TAKE SERVICE UNDER TARIFF E.D.R.

A. There are two primary reasons: First, Ebon's Total Capacity Reservation exceeds the current MW cap for Tariff E.D.R. Approximately 211 MW remains unsubscribed under Tariff E.D.R., while the contract capacity for the Ebon Facility is planned for 250 MW. Second, Ebon required a more complex billing calculation than is possible under any of the Company's tariffs.

Q. [redacted]

A. [redacted]

Q. IS EBON LIMITED TO TAKING SERVICE UNDER THE TERMS OF THE SPECIAL CONTRACT FOR THE ENTIRE TERM?

A. No. Although the Company expects Ebon to take service at the rates set out in the Special Contract for the entire term of the Special Contract, should Ebon wish to take

[2] https://datausa.io/profile/geo/louisa-ky

service under the Company's standard tariff, the Company will transition Ebon to the applicable tariff.

Q. WHAT ARE THE EFFECTIVE DATE AND TERM OF THE SPECIAL CONTRACT?

A. Per Article 6.1, the Special Contract becomes effective on the first day of the first billing month following the date when Ebon provides written notice to the Company that the Ebon Facility has begun commercial operation and after the receipt of approval of the Special Contract by the Commission. The initial term of the Special Contract is 10 years beginning with the effective date (Article 6.2). The Special Contract will not become effective without the Commission's approval.

Q. DOES THE SPECIAL CONTRACT ADDRESS WHAT WILL OCCUR AT THE END OF ITS TERM?

A. Yes. Article 6.3 requires that, no later than January 1, 2030, the Parties shall meet to discuss the Customer taking service under an appropriate Company tariff upon expiration of the term of the Special Contract or renewal of the current contract, including any revisions agreed to by the Parties, for another 10-year term.

Q. IS THE SPECIAL CONTRACT'S PRICING STRUCTURE REASONABLE?

A. Yes, it is. [redacted] Therefore, the Special Contract provides benefits to Ebon, the Company's other customers, the Commonwealth, and the Company.

Q. WHAT PROTECTS KENTUCKY POWER FROM EBON DEFAULTING ON THE SPECIAL CONTRACT PRIOR TO THE 10-YEAR CONTRACT ERM?

A. While a default is not anticipated, there are remedies under the laws of the Commonwealth for the Company to enforce the terms of the Special Contract with Ebon should it default. Also, [redacted]

VI. CONFIDENTIAL TREATMENT

Q. IS KENTUCKY POWER SEEKING CONFIDENTIAL TREATMENT OF THE SPECIAL CONTRACT'S RATE-RELATED PROVISIONS AND CONFIDENTIAL EXHIBIT 1?

A. Yes. Kentucky Power is seeking confidential treatment for: (a) the entirety of Confidential Exhibit 1; (b) Article 5.1(A) through Article 5.1(H) of the Special Contract; and (c) discussion of topics (a) and (b) contained in this testimony (collectively the "Confidential Rate Information"). Each of the portions of the Company's filing designated as Confidential Rate Information either constitutes or reflects the Special Contract rates.

Q. PLEASE DESCRIBE THE UNFAIR COMPETITIVE INJURY TO KENTUCKY POWER AND TO EBON IF THE CONFIDENTIAL RATE INFORMATION IS MADE PUBLIC.

A. Whether mining cryptocurrencies or providing data processing services to other high-tech business described above, Ebon operates in a highly competitive industry in which cost information is highly protected for competitive advantage. The cryptocurrency mining and data services industry is driven by access to power with the cost of electric power accounting for over 90 percent of the operational costs of providing such services.[3] Consequently, Ebon seeks to maintain confidentiality regarding the cost of power it obtains from Kentucky Power under this Special Contract. Similar to other industrial customers (steel, aluminum, pulp and paper), Ebon needs to maintain confidentiality regarding the cost of the commodities and services it competes to sell. Ebon will suffer injury by any public release of the confidential portions of the Special Contract because its competitors will gain access to the most sensitive information regarding its cost of operations.

Further, making the rates public would establish a ceiling for future rates negotiated with other similar customers looking to locate in Kentucky Power's service territory, or potentially for existing customers asking to establish new rates through special contracts. Common sense and experience teach that future prospects will demand rates that meet or are less than the Ebon rates. Kentucky Power might be faced with meeting or beating the rates in the Special Contract or risk losing the prospective new business. In addition, existing customers also could seek similar rates with respect to both existing and any expanded load. This means that the Confidential Rate Information cannot be disclosed to existing customers or to the more general public.

Q. DOES CONFIDENTIAL EXHIBIT 1 TO THE APPLICATION REFLECT THE SPECIAL CONTRACT RATES?

[3] *See* https://www.reuters.com/article/us-markets-bitcoin-mining-idUSKCN0ZO2CW (last accessed September 19, 2022).

A. Yes. Confidential Exhibit 1 also reflects the confidential strategy Kentucky Power used to negotiate the Special Contract and design its rates. The disclosure of such information would jeopardize the Company's ability to fairly negotiate future special contracts.

Q. DOES KENTUCKY POWER TAKE ALL REASONABLE STEPS TO PROTECT THE CONFIDENTIAL RATE INFORMATION FROM PUBLIC DISCLOSURE?

A. Yes. Dissemination of the Confidential Rate Information is restricted by Kentucky Power, its parent, AEP, and American Electric Power Service Corporation ("AEPSC"). The Company, AEP, and AEPSC take all reasonable measures to prevent its disclosure to the public as well as to persons within the Company and third-party vendors who do not have a need for the information. Within those organizations, the information is available only upon a confidential need-to-know basis that does not extend beyond those employees with a legitimate business need to know and act upon the identified information.

It is my understanding that Ebon also maintains the Confidential Rate Information as confidential and protects it from disclosure.

Q. IS THE CONFIDENTIAL RATE INFORMATION OTHERWISE AVAILABLE TO COMPETITORS AND CUSTOMERS OF KENTUCKY POWER AND EBON?

A. No, the information is not publicly available. Nor can it be reasonably discerned through lawful means.

Q. FOR WHAT PERIOD IS KENTUCKY POWER SEEKING CONFIDENTIAL TREATMENT OF THE CONFIDENTIAL RATE INFORMATION?

A. Kentucky Power requests the Confidential Rate Information be kept confidential for the term of the Special Contract.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and states he is Vice President, Regulatory & Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the information contained therein is true correct to the best of his information, knowledge, and belief after a reasonable investigation.

Brian K. West

Commonwealth of Kentucky)
)
County of Boyd)

Subscribed and sworn before me, a Notary Public, by Brian K. West this 17th day of October, 2022.

Scott E. Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires: June 24, 2025

EXHIBIT 1

CONTRACT FOR
FIRM ELECTRIC SERVICE
BETWEEN KENTUCKY POWER COMPANY
AND EBON INTERNATIONAL, LLC

This Contract for Firm Electric Service ("Contract") is entered into by and between Kentucky Power Company, a Kentucky corporation (the "Company"), and Ebon International, LLC, a Delaware limited liability company (the "Customer") on the date this Contract is last signed.

RECITALS

1. The Company is a corporation organized and existing under the laws of the Commonwealth of Kentucky that owns and operates facilities for the generation, transmission and distribution of electric power and energy in the Commonwealth of Kentucky.

2. Customer is a limited liability company organized and existing under the laws of the State of Delaware and is registered to do business in Kentucky and New Jersey. Customer's principal place of business in the Commonwealth is located in Lawrence County, Kentucky.

3. The Company's service territory and the entire eastern Kentucky region are struggling economically and is in need of a transformative influx of new industry and jobs for its citizens.

4. In order to foster the fundamental changes necessary to revive the economy of the Company's service territory and the eastern Kentucky region, large industrial development is necessary. Customer is in a unique position to bring significant load to the Company's service territory, along with new jobs, thus assisting the region in its economic development efforts.

5. The Customer plans to invest at a minimum $50 million at the Customer's Facility and to create at least 50-100 new permanent full-time jobs by June 2024 (or sooner), when the Customer's Facility is expected to begin full operations. The Customer also anticipates that its monthly maximum billing demand will equal or exceed 100,000 kW (100 MW) by June 2024.

6. To facilitate economic development in the Company's service territory through the construction and operation of the Customer's Facility in eastern Kentucky, including the benefits flowing to all customers through spreading fixed costs, the Company is agreeable to providing energy to Customer under the terms and conditions contained in this Contract, subject to approval by the Public Service Commission of Kentucky.

7. The Customer has demonstrated to the Company that absent the availability of the rates provided by this Contract, the Customer's Facility, and its electrical demand, would not be placed in service.

8. In recognition of the need for the efficient use of existing utility generation and transmission facilities, the Company and Customer agree to the special rate design contained in this Contract.

9. The service the Company will provide Customer pursuant to this Contract will provide benefits to the Customer, the Company's other customers, the Company, and the Commonwealth of Kentucky.

10. Customer's anticipated load in the first two years of operation is 100 MW. Thereafter, after a new substation is constructed, Customer's anticipated load is expected to grow to 250 MW. The parties acknowledge that the electrical infrastructure for the Company to

provide, and for Customer to take, the anticipated load at Customer's Facility does not presently exist. Customer and the Company will use their best efforts to install, construct, and maintain the necessary electrical infrastructure to permit the Company to provide, and the Customer to take the anticipated load.

NOW, THEREFORE, in consideration of the promises and the mutual covenants herein contained, and subject to the terms and conditions herein contained, the Company and the Customer agree as set forth below.

CONTRACT

ARTICLE 1
Definitions

1.1 Whenever used in this Contract, the following terms shall have the meanings set forth below, unless a different meaning is plainly required by the context:

A. "Capital Spare" shall mean a skid transformer station owned by the Company, with a typical capacity 30 MVA rating.

B. "Commission" shall mean the Public Service Commission of Kentucky, the regulatory agency having jurisdiction over the retail electric service of the Company in Kentucky, including the electric service covered by this Contract or any successor thereto.

C. "Company" shall mean Kentucky Power Company, its successors and assigns.

D. "Contract" shall mean this Contract for electric service between the Company and the Customer, as the same may, from time to time, be amended.

E. "Customer" shall mean Ebon International, LLC.

F. "Facility" shall mean and be limited to the following location that is wholly owned by the Customer: 23250 US Highway 23, Louisa, Kentucky 41230.

G. "Kentucky Power System" shall mean the integrated, interconnected electric system operated and owned by Kentucky Power Company.

H. "Parties" shall mean the Company and the Customer.

I. "Party" shall mean either the Company or the Customer.

J. "Tariff I.G.S." shall mean the Company's Industrial General Service Tariff, or any successor or amendment thereto, approved by the Commission.

K. “Off-Peak Period” shall be as defined in Tariff I.G.S. The current Off-Peak Period is defined as between 9:00 PM to 7:00 AM, local time, for all weekdays, Monday through Friday, and all hours of the day on Saturdays and Sundays.

L. “On–Peak Period” shall be as defined in Tariff I.G.S. The current On-Peak Period is defined as between 7:00 AM and 9:00 PM, local time, for all weekdays, Monday through Friday.

M. "Tariff D.R.S." shall mean the Company's Demand Response Service Tariff, or any successor or amendment thereto, approved by the Commission.

N. “Tariff F.A.C.” shall mean the Company’s Fuel Adjustment Clause Tariff, or any successor or amendment thereto, approved by the Commission.

O. “Interruptible Capacity” shall mean the amount of load in megawatts (“MW”) the Customer agrees to interrupt in accordance with this Contract and the terms of Tariff D.R.S.

P. “Floor Price” shall be defined as the minimum monthly charge the Company and Customer have agreed to in Article 5.1(C) and is expressed in cents per kWh.

Q. “Floor Price Bank” shall be defined as any accumulated credits or debits when the Customer’s bill is required to be increased or decreased to meet the Floor Price

R. “Total Bill” means the total amount due from Customer to the Company as computed in accordance with this Contract and as shown on the monthly billing statement rendered by the Company to the Customer.

S. “Phase One” means the period between the effective date of this Contract and the date of the commencement of electrical operation of Customer’s Substation.

T. “Phase Two” means the period beginning with the commencement of electrical operation of Customer’s Substation.

U. “Customer’s Substation” means that electrical transformation substation to be constructed at Customer’s sole cost at or near the site of Customer’s Facility and that will be electrically sufficient to support a load of no less than 250 MW.

V. “Capacity Discount” shall mean the Billing Demand Discount.

W. “Incremental Discount” shall mean the Incremental Billing Demand Discount.

1.2 Unless the context plainly indicates otherwise, words importing the singular number shall be deemed to include the plural number (and vice versa); terms such as "hereof," "herein," "hereunder" and other similar compounds of the word "here" shall mean and refer to the entire Contract rather than any particular part of the same. Certain other definitions, as required, appear in subsequent parts of this Contract.

ARTICLE 2
Delivery of Power and Energy

2.1 Subject to the terms and conditions specified herein, the Parties agree that the Company will furnish to the Customer, during the term of this Contract, all of the electric power and energy that shall be required by the Customer for consumption at the Facility.

2.2 The Delivery Point for electric power and energy delivered hereunder shall be at the interconnection of the Company's facilities to the Customer's facilities located in the Customer's Substation that will serve the Facility.

A. Kentucky Power will use reasonable efforts beginning with the effective date of this Contract to install and maintain, if possible, up to three Capital Spares, with a total capacity of up to approximately 90 MW at Customer's Facility while Customer's Substation is being constructed. Customer acknowledges that the Company will use reasonable best efforts to acquire and install the Capital Spares individually and that the approximate 90 MW of capacity will not be initially available. Customer further acknowledges the Company and Customer will enter into a separate contract with regard to providing the Capital Spares.

B. Customer and the Company will execute a separate contract regarding the Customer's Substation. The Customer will provide any substation and transformation equipment and any other facilities including real property required to take delivery of the electric service to be provided by the Company under this Contract at the voltage and at the Delivery Point designated herein.

2.3 The electric energy delivered by the Company shall be three-phrase alternating current having a frequency of approximately 60 cycles per second at approximately 138,000 volts and shall be delivered at the Delivery Point specified in Article 2.2. The electric energy shall be delivered and maintained reasonably close to constant voltage and frequency, as required by Company tariffs, and shall be measured by meters owned and installed by the Company and located at the Customer's Substation. The Company shall have the right to enter the Customer's Substation to read and maintain the Company's meters.

ARTICLE 3
Capacity Reservations and Designation of Firm Service

3.1 The Total Capacity Reservation contracted for by the Customer during Phase One shall be equal to the Company's electrical ability to deliver electrical capacity to Customer at the Facility. As set forth in Section 2.2, the Company shall use its reasonable efforts to install, if possible, three Capital Spares at or near the Facility to permit the Company to deliver up to approximately 90 MW to the Customer's Facility. The Company and the Customer agree that the Customers Total Capacity Reservation shall vary during Phase One based on the Company's ability to deliver electrical capacity to the Customer's Facility. The Total Capacity Reservation contracted for by Customer during Phase Two shall be 250 MW. The Customer may request an increase or decrease in the Total Capacity Reservation by providing written notice to the Company one year in advance of the date the requested change is proposed to be effective. The

Parties may reduce the one-year written notice requirement by mutual written agreement. Any increase to the Total Capacity Reservation is subject to the availability and cost of incremental Capacity from the Company, and to the receipt of any necessary regulatory approvals.

3.2 The Customer's Interruptible Capacity for Phase One is equal to 90 percent of the Customer's Total Capacity Reservation as it may vary from time to time and as defined in Article 3.1. The Customer's Interruptible Capacity for Phase Two is 225 MW. The Customer's Firm Service Capacity Reservation for Phase One is equal to ten percent of the Customer's Total Capacity Reservation as it may vary from time to time and as defined in Article 3.1. The Customer's Firm Service Capacity Reservation for Phase Two is 25 MW. The Interruptible Capacity for Phase One and for Phase Two for purposes of Tariff D.R.S. shall be calculated, upon approval of this Contract by the Commission, in accordance with Article 3 of this Contract and without regard to any conflicting provisions of Tariff D.R.S. The Firm Service Capacity Reservations for Phase One and Phase Two identified in this paragraph are not subject to interruption in accordance with Tariff D.R.S. or this Contract.

3.3 The Customer's Metered Demand shall not exceed, and the Company shall not be required to supply capacity in excess of, one hundred twenty percent (120%) of the Total Capacity Reservation, except by mutual written agreement of the Parties.

3.4 The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

ARTICLE 4
Interruptible Service – Discretionary Interruption Product

4.1 The Company in its sole discretion, reserves the right to call for curtailments of Customer's Interruptible Capacity at any time by notifying Customer, in accordance with Section 4.6 herein, to maintain its usage at its Firm Service Capacity Reservation level. Such curtailments shall be designated as Discretionary Interruption events; Discretionary Interruption events shall not exceed an aggregate of 60 hours of interruption during any Interruption Year. The Interruption Year shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31.

4.2 The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. If the Customer fails to comply with an interruption event, the Customer shall pay back a portion of its DRS credit in accordance with the DRS Event Failure Charge section of the Commission-approved Tariff D.R.S. as it may be amended from time to time.

4.3 The Customer will be determined to have failed a Discretionary Interruption event and to be liable for the DRS Event Failure Charge if the Customer has not achieved at least ninety percent (90%) of their agreed upon Interruptible Capacity reservation during the duration of a Discretionary Interruption.

4.5 Discretionary Interruption events shall be in increments of three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per calendar day.

4.6 The Company will notify the Customer of Discretionary Interruptions through the webDistribute System ("wDS"), or any successor system thereto, to be provided to the Customer by the Company. The Customer is ultimately responsible for receiving and acting upon a Discretionary Interruption notification from the Company provided to it through the wDS.

4.7 **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY, ANY AFFILIATE, OR THE AEP SYSTEM FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OR SERVICE UNDER THE PROVISIONS OF THIS SPECIAL CONTRACT.**

ARTICLE 5
Billing

5.1 The Customer agrees to pay for all electric service supplied hereunder in accordance with the provisions set forth in subparagraphs 5.1(A)-(D) below. Customer agrees and acknowledges that the pricing under this Contract is being provided by the Company to the Customer based upon Customer's agreement to take service at or above its Total Capacity Reservation during the contract term.

<u>CONFIDENTIAL RATE INFORMATION - BEGIN</u>

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

CONFIDENTIAL RATE INFORMATION - END

5.2 Bills computed under this Contract are net if the account is paid in full within fifteen (15) days of the mailing date of the bill. Bills are to be sent concurrently using conventional mail as well as electronic mail. On accounts not so paid, a late charge equal to five percent (5%) of the unpaid balance shall be added to Customer's Total Bill balance. Customer Floor Bank credits shall not be applied to the amount of any late charge. Unless otherwise stated in this Contract, the standard billing and payment provisions of Tariff I.G.S. shall apply.

5.3 Temporary construction power and electric service shall be provided and billed under the otherwise applicable retail tariff(s) until the Effective Date as defined in Article 6.1 below.

5.4 An illustrative billing calculation based upon current Tariff I.G.S. rates is included as **Confidential Exhibit 1**, incorporated by reference and made a part of this Contract. The Company's rates are subject to change. This calculation is for illustrative purposes only and not a guarantee of future rates. The rates illustrated are current as of July 2022.

5.5 Customer acknowledges that the rates under this Contract are contingent upon Customer achieving and maintaining thereafter an average on-peak monthly demand of 250 MW no later than the later of June 2024 or twenty-four (24) months after the effective date of this Contract. In the event, beginning 12 months after the effective date of this Contract, Customer's average on-peak monthly demand, calculated on a calendar month basis, is less than 25 MW, the standard rates, billing, and payment provisions of Tariff I.G.S. shall apply to that month's billing. The Customer's average on-peak monthly demand, calculated on a calendar month basis, will be calculated based on the most recent available billing data prior to the billing month.

ARTICLE 6
Effective Date And Term Of Contract

6.1 The Effective Date of this Contract shall be the first day of the first billing month following the date when the Customer provides written notice to the Company that the Facility has begun commercial operation and after the receipt of all required regulatory approvals. In no event shall this Contract become effective without the approval of this Contract by the Commission as required by Article 8.2.

6.2 The initial term of this Contract shall be for ten (10) years. The period shall commence on the Effective Date of this Contract as established under Article 6.1.

6.3 No later than January 1, 2030, the Parties shall meet to discuss the Customer taking service under an appropriate Company tariff upon expiration of the term of this Contract or renewal of the current contract, including any revisions agreed to by the Parties, for another 10-year term.

ARTICLE 7
Service Conditions

7.1 Each Party shall exercise reasonable care to maintain and operate, or to cause to be maintained and operated, their respective facilities in accordance with good engineering and utility practices.

7.2 To the extent not expressly modified by this Contract, the Company's Terms and Conditions of Service, as filed with the Commission, including any amendments thereto, are incorporated by reference and made a part of this Contract. In the event of a conflict between express provisions of this Contract and the provisions of the Company's Terms and Conditions of Service, the provisions of this Contract shall control.

7.3 In addition to any Discretionary Interruption under Article 4, any service being provided to the Customer under this Contract may also be interrupted or reduced by the Company without compensation (a) by operation of equipment installed for power system protection; (b) after adequate notice to and consultation with the Customer for routine installation, maintenance, inspection, repairs, or replacement of equipment; or (c) when, in the Company's sole judgment, such action is necessary to (i) preserve the integrity of, or to prevent or limit any instability or material disturbance on the Kentucky Power System or an interconnected system, (ii) preserve personal or public safety, or (iii) protect property. To the extent practicable, Company shall provide Customer with at least 15 days' written notice with respect to, and otherwise use reasonable efforts when undertaking, the activities described in (b) above, and shall work with Customer to schedule such interruptions or reductions as are permitted under this Article so as to minimize to the extent practicable any impact on Customer's operations. No such interruption shall constitute a Discretionary Interruption under Article 4.

7.4 The Company reserves the right to disconnect from the Kentucky Power System the Customer's conductors or apparatus without notice when, in the exercise of reasonable care, the Company determines that it is necessary in the interest of preserving or protecting life and/or property.

7.5 During the term hereof, the Customer shall not receive electric service, as the term "service" is defined in Chapter 278 of the Kentucky Revised Statutes, from any source other than the Company. However, this provision does not apply to generation that is not designed or required to operate in parallel with the Kentucky Power System and which Customer utilizes to mitigate the impact of any interruption or reduction as might occur in accordance with Article 7.3 herein.

7.6 The Customer shall notify the Company in advance of any change to be made to the Customer's Facility that the Customer knows or reasonably should know has the potential to materially affect the Kentucky Power System or other facilities interconnected to the Kentucky Power System including, for example, the installation of equipment that would change power factor or generate electrical harmonics.

7.7 The Customer represents and warrants that it is the sole owner of the Facility.

7.8 The Customer shall adhere to the addendum to this Contract (**Exhibit 3**) regarding voltage flicker criteria and harmonic distortion criteria, which is incorporated by reference and made a part of this Contract.

7.9 The Customer shall adhere to the Company's Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System (Effective: June 30, 2021) (**Exhibit 4**), or any successor requirements, including Section 4.3 of those requirements.

ARTICLE 8
Regulatory Authorities

8.1 The Parties recognize that this Contract is subject to the jurisdiction of the Commission and is also subject to such lawful action as any regulatory authority having jurisdiction shall take with respect to the provision of services under the Contract. The performance of any obligation of either Party shall be subject to the receipt of such authorizations, approvals or actions of such regulatory authorities having jurisdiction as shall be required by law.

8.2 The Company and the Customer agree that this Contract reflects steps required to ensure adequate service to the Customer and that the Company will file this Contract with the Commission. This Contract is expressly conditioned upon the issuance of a final and non-appealable order by the Commission approving the Contract without material change or condition. Should the Commission issue an order rejecting this Contract or approving this Contract with conditions or modifications that materially alter the commercial aspects of this Contract, the Parties agree to use good faith efforts to renegotiate this Contract and to file the amended Contract with the Commission seeking approval thereof. During the period of such negotiations and approval, or in the event that no such amended Contract is filed, the Customer shall take service under an applicable retail tariff.

ARTICLE 9
Assignment

9.1 This Contract shall inure to the benefit of and be binding upon the successors and assigns of the Parties.

9.2 This Contract shall not be assigned by either Party without the written consent of the other Party, such consent not to be unreasonably withheld.

9.3 Any assignment by one Party to this Contract shall not relieve that Party of its financial obligation under this Contract unless the other Party so consents in writing.

ARTICLE 10
General

10.1 Any waiver at any time of any rights as to any default or other matter arising under this Contract shall not be deemed a waiver as to any other proceeding or subsequent default or matter. Any delay, excepting the applicable statutory period of limitation, in asserting or enforcing any right hereunder shall not be deemed a waiver of such right.

10.2 Except as set forth in Article 8, in the event that any of the provisions, or portions thereof, of this Contract is held to be unenforceable or invalid by any court of competent jurisdiction, the validity and enforceability of the remaining provisions, or portions thereof, shall not be affected.

10.3 All terms and stipulations made or agreed to regarding the subject matter of this Contract are completely expressed and merged in this Contract, and no previous promises, representations or agreements made by the Company's or the Customer's officers or agents shall be binding on either Party unless contained herein.

10.4 Except as set forth in Article 4, all notices permitted or required to be given hereunder shall be in writing and shall be delivered by first-class mail to the Company and to the Customer at their respective addresses set forth below. When a notice is mailed pursuant to this paragraph, the postmark shall be deemed to establish the date on which the notice is given:

If to Company:

Vice President, Regulatory & Finance
Kentucky Power Company
1645 Winchester Avenue
Ashland, KY 41101

If to Customer:

Ebon International, LLC
23250 US Highway 23
Louisa, Kentucky 41230

10.5 The rights and remedies granted under this Contract shall not be exclusive rights and remedies but shall be in addition to all other rights and remedies available at law or in equity.

10.6 The validity and meaning of this Contract shall be governed by the laws of the Commonwealth of Kentucky without regard to conflict of law rules.

10.7 This Contract may be executed in counterparts, each of which shall be an original, but all of which, together, shall constitute one and the same Contract.

IN WITNESS WHEREOF, the Parties hereto have caused this Contract to be duly executed the day and year last written below.

KENTUCKY POWER COMPANY		**EBON INTERNATIONAL, LLC**	
By	Brian K. West	By	Hongwong Wang
Title	VP, Regulatory & Finance	Title	Director
Date	08/23/2022	Date	08/22/2022

Exhibit 1 is confidential in its entirety.

KENTUCKY POWER COMPANY P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 36-1 T
CANCELLING P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 36-1 T

RIDER D.R.S. T
(Demand Response Service)

AVAILABILITY OF SERVICE N

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

CONDITIONS OF SERVICE

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

(Cont'd On Sheet 36-2)

DATE OF ISSUE: April 9, 2021
DATE EFFECTIVE: Service Rendered On And After January 14, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of Orders of the Public Service Commission
In Case No. 2020-00174 dated January 13, 2021; January 15, 2021; February 22, 2021, and March 17, 2021

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/14/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

RIDER D.R.S. (Cont'd)
(Demand Response Service) N

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

8. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.**

INTERRUPTIBLE CAPACITY RESERVATION

The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.

MONTHLY INTERRUPTIBLE DEMAND CREDIT

The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

INTERRUPTION EVENT COMPLIANCE

A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

(Cont'd On Sheet 36-3)

DATE OF ISSUE: April 9, 2021
DATE EFFECTIVE: Service Rendered On And After January 14, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of Orders of the Public Service Commission
In Case No. 2020-00174 dated January 13, 2021; January 15, 2021; February 22, 2021, and March 17, 2021

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/14/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

KENTUCKY POWER COMPANY P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 36-3 T
CANCELLING P.S.C. KY. NO. XX________ SHEET NO. 36-3 T

N

RIDER D.R.S. (Cont'd)
(Demand Response Service)

DRS EVENT FAILURE CHARGE

A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

Number of Failures	Penalty Payment %
Failure 1	5%
Failure 2	10%
Failure 3	10%
Failure 4	15%
Failure 5	15%
Failure 6	20%
Failure 7	25%
Totals	100%

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

SETTLEMENT

The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

TERM

A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

D

DATE OF ISSUE: April 9, 2021
DATE EFFECTIVE: Service Rendered On And After January 14, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of Orders of the Public Service Commission
In Case No. 2020-00174 dated January 13, 2021; January 15, 2021, February 22, 2021, and March 17, 2021

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/14/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

ADDENDUM TO CONTRACT FOR ELECTRICAL DISTRIBUTION SERVICE-Flicker/Harmonics

This Addendum is entered into this ___ day of __________, 2022, by and between **Kentucky Power Company**, hereafter called the Company, and **Ebon International, LLC**, or its heirs, successors or assigns, hereafter called the Customer.

WHEREAS, the Company's terms and conditions of service contained in the applicable tariffs indicate that the Customer shall not use the electrical service provided for under the terms of the Contract for Electric Service dated _____________in a manner detrimental to other customers or in such a way as to impose unacceptable voltage fluctuations or harmonic distortions, and

WHEREAS, the Customer anticipates utilizing certain equipment at the service location covered by the Contract that could impose an unacceptable level of voltage flicker or harmonic distortion,

NOW THEREFORE, the parties hereby agree as follows:

I. POINT OF COMPLIANCE – The point where the Customer's electric system connects to Kentucky Power's system will be the point where compliance with the voltage flicker and harmonic distortion requirements are evaluated.

II. VOLTAGE FLICKER CRITERIA – The Company's standards require that the voltage flicker occurring at the Point of Compliance shall remain below the Border Line of Visibility curve on the Flicker Limits Curve of IEEE Standard 141.

The Customer shall design and operate its facility in compliance with the voltage flicker criteria contained in IEEE Standard 1453, "IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems."

Notwithstanding these criteria, the Customer has certain equipment that it anticipates utilizing at the service location covered by the Contract that could impose a level of voltage flicker above the Border Line of Visibility curve The Company agrees to permit the Customer to operate above the Border Line of Visibility curve unless and until the Company receives complaints from other customers or other operating problems arise for the Company, provided that the voltage flicker does not exceed the Border Line of Irritation curve shown on the Flicker Limits Curve, whether or not complaints or operating problems occur. By so agreeing, the Company does not waive any rights it may have to strictly enforce its established voltage flicker criteria as measured/calculated in the future. All measurements shall be determined at the Point of Compliance and compliance with these criteria shall be determined solely by the Company.

If the Customer is operating above the Border Line of Visibility curve and complaints are received by the Company or other operating problems arise, or should the Customer's flicker exceed the Border Line of Irritation curve, the Customer agrees to take action, at the Customer's expense, to comply with the Voltage Flicker Criteria. Corrective measures could include, but are not limited to, modifying production methods/materials or installing voltage flicker mitigation equipment necessary to bring the Customer's operations into compliance with the Voltage Flicker Criteria.

If the Customer fails to take corrective action within a reasonable time, not to exceed 90 days, after notice by the Company, the Company shall have such rights as currently provided for under its tariffs, which may include discontinuing service, until such time as the problem is corrected.

III. HARMONIC DISTORTION CRITERIA – The Customer shall design and operate its facility in compliance with the harmonic distortion criteria contained in IEEE Standard 519.

The Customer agrees that if the operation of motors, appliances, devices or apparatus results in harmonic distortions in excess of the Company's Harmonic Distortion Criteria, it will be the Customer's responsibility to take action, at the Customer's expense, to comply with such Criteria. If the Customer fails to take corrective action within a reasonable time, not to exceed 90 days, after notice by the Company, the Company shall have such rights as currently provided for under its tariffs, which may include discontinuing service, until such time as the problem is corrected.

IV. OTHER REQUIREMENTS

Compliance Assessment — To achieve compliance, at least 95% of all recordings within each harmonic measure and 99% within each flicker measure must fall below the applicable limit, i.e., Customer will be in material non-compliance with the Company's Power Quality Requirements if more than 5% of the harmonic voltage and harmonic current recordings and 1% of the flicker recordings exceed the specified limits.

Electrical Interactions — If power quality compliance monitoring recordings or analytical studies conducted by the Company indicate likely adverse electrical interactions between the Customer and the Kentucky Power's System, joint efforts will be undertaken by the Parties to determine the nature and extent of the electrical interaction and to resolve, at no expense to the Company, any likely adverse impacts on the performance of Company facilities.

Kentucky Power Company	**Ebon International, LLC**
Date: ____________________	
By: ______________________________________	By: ______________________________________
Printed Name: _____________________________	Printed Name: ____________________________
Title:	Title:
Date: ____________________	Date: ____________________

Account Number: **Not Yet Assigned**

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY℠

Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System

Effective: June 30, 2021

Document Control

Revision History

Version	Effective Date	Remarks
Rev. 0	12/08/2010	Combined AEP East and AEP West Interconnection Requirements
Rev. 1	01/02/2014	Periodic Review
Rev. 2	01/01/2019	New FAC-001-3 Requirements, Appendix B Rework, & Periodic Review
Rev. 3	06/30/2021	Complete document reorganization to better align with standard processes, adjustment of requirements needing updates, and addition of 4th customer category for Distributed Energy Resources

Preparation

Prepared By
AEP Transmission Subject Matter Experts

Review Cycle

Quarterly	Semi-annual	Annual	As Needed
			X

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1.0 Document Overview

This document describes the processes and technical requirements for new or materially modified facility connections to the American Electric Power (AEP) system's electrical transmission network.

AEP[1] is responsible for evaluating its transmission network capabilities and formulating plans that maximize functionality and operation in a safe, reliable, cost effective, and environmentally responsible manner. AEP Transmission created the requirements in this document to ensure the transmission system's integrity when providing new or materially modified facility connections. All future Requester facilities, loads, major equipment or setting changes must be submitted to AEP for review before they are placed in service. The Requester is responsible for obtaining the requirements from the regional transmission entity (RTE)[2] within which their operation exists.

This document contains the minimum requirements acceptable for affiliated and non-affiliated connections to the AEP transmission system. The requirements and processes described in this document will guide the planning for new facility installations and upgrading existing facilities. In some specific cases, AEP may request additional details.

For purposes of this requirements document, AEP transmission interconnections are organized into four categories: Distributed Energy Resource (DER), End-User Connection (EUC), Generator Connection (GC), and Transmission Interconnection (TI). Each subsection contains the general requirements that apply to all interconnection categories and indicates any requirements that may be specific to a single category. See *Section 2.0 Initial Engagement* for more information.

AEP has seven electric utilities referred to as Affiliate Operating Companies, and seven electric utilities referred to as Transmission Companies that are geographically dispersed across 11 states. RTEs support and assist with the operation and usage of the larger integrated or interconnected regional transmission system and are generally responsible for ensuring the regional transmission system's safe and reliable operation. Nothing within this document is intended to conflict with applicable RTE requirements.

Entities requesting a Transmission Interconnection are required to register within a Balancing Authority (BA) with their respective RTE. The interconnecting facilities will not be energized until AEP verifies that this registration is complete.

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[1] AEP Service Corporation is an agent for Electric Transmission Texas (ETT), Electric Transmission America (ETA), PATH West Virginia, and the Transource entities located in Maryland, Missouri, Pennsylvania, and West Virginia.
[2] Regional transmission entity or RTE – For the purpose of this document, any regional body having jurisdiction over a party, including the applicable RTO, ISO, or regional electric reliability organization under NERC authority.

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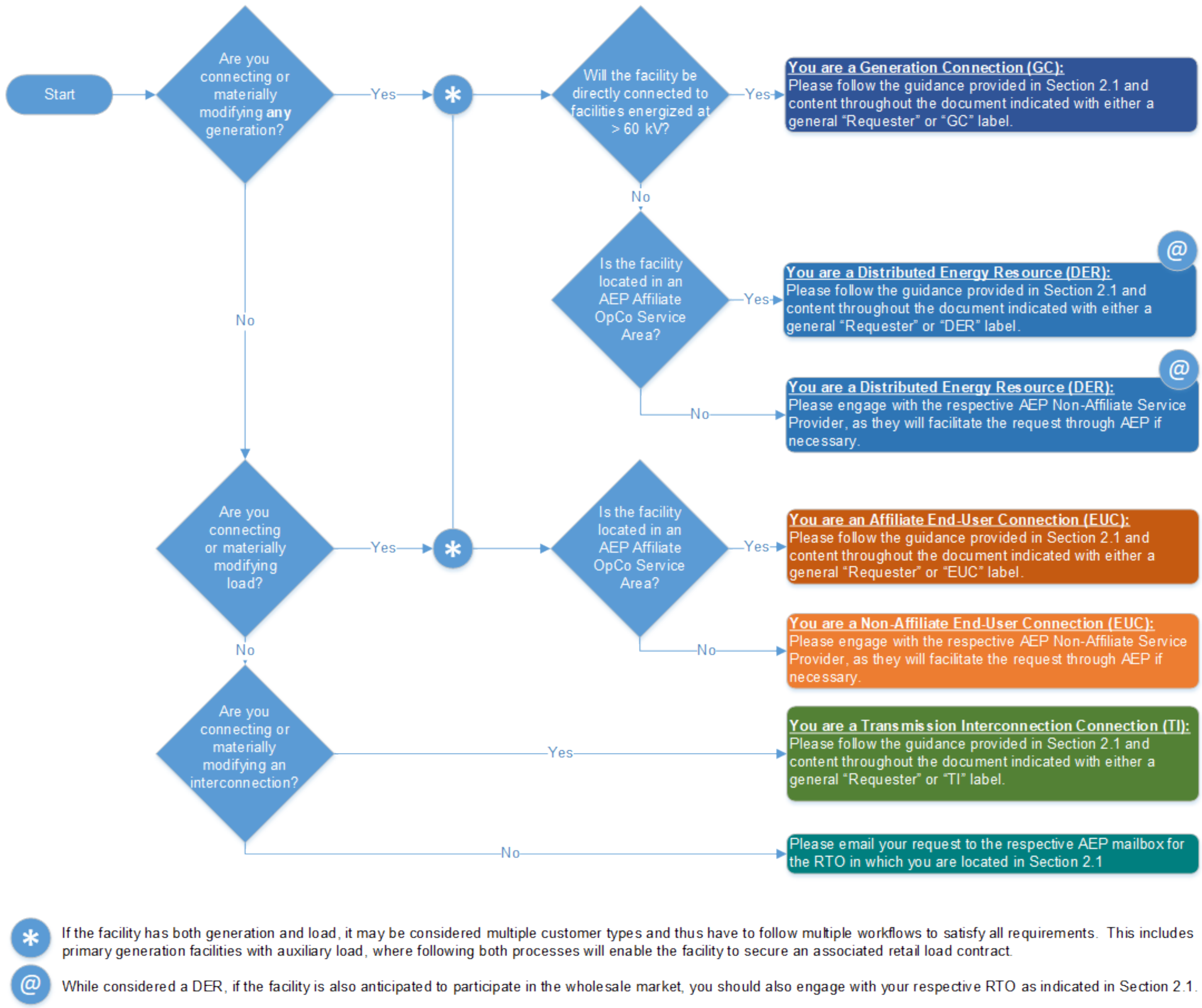
2.0 Initial Engagement

This section explains the first steps the Requester should take when initiating a modification or new connection to the transmission infrastructure. To assist in the understanding of this section and the references to each respective connection type throughout this document, refer to the flowchart in *Figure 1* below.

Figure 1. Requester Connection Decision Type Tree



2.1 Procedures

2.1.1 Procedures for Requesting New or Materially Modified Interconnections

This section outlines the first point of contact for requesting new or material modifications to existing connections. Refer to the flowchart in *Figure 1* to determine connection type and requirements. The definitions of each region and connection type are in *Appendix A Definitions*. In addition, the processes, data requirements, and procedures for sharing results for these particular requests are located in *Sections 2.1.2*, *2.2.1*, and *2.2.2*.

Table 1. First Point of Contact for Requesting New or Materially Modified Interconnections

Region	**State**	**Connection Type**			
		DER	GC	EUC	TI
ERCOT[3]	Mid/South Texas	AEP Texas[4]	≤10 MW: SIS[5] ERCOT Mailbox[6] >10 MW: ERCOT Website[7]	SIS ERCOT Mailbox[6]	SIS ERCOT Mailbox[6]
SPP[8]	North Texas	AEP SWEPCO[9]	SPP Website[10]	SIS SPP Mailbox and SPP AQ Mailbox[11]	SIS SPP Mailbox[12]
	Arkansas				
	Louisiana				
	Oklahoma	AEP PSO[13]			
PJM [14]	Indiana	AEP I&M[15]	PJM Website[16]	SIS PJM Mailbox[17]	SIS PJM Mailbox[17]
	Michigan				
	Ohio	AEP Ohio[18]			
	West Virginia	AEP APCo[19]			
	Tennessee				
	Virginia				
	Kentucky	AEP KPCo[20]			

[3] Electric Reliability Council of Texas
[4] https://www.aeptexas.com/builders/GeneratingEquipment.aspx
[5] System Interconnection Services
[6] ERCOTrequest@aep.com
[7] http://www.ercot.com/services/rq/re/
[8] Southwest Power Pool
[9] https://www.swepco.com/builders/GeneratingEquipment.aspx
[10] http://opsportal.spp.org/Studies/Gen
[11] SPPrequest@aep.com and AQ-deliverypoints@spp.org
[12] SPPrequest@aep.com
[13] https://www.psoklahoma.com/builders/GeneratingEquipment.aspx
[14] PJM Interconnection
[15] https://www.indianamichiganpower.com/builders/GeneratingEquipment.aspx
[16] http://pjm.com/planning/generation-interconnection.aspx
[17] PJMrequest@aep.com
[18] https://www.aepohio.com/builders/GeneratingEquipment.aspx
[19] https://www.appalachianpower.com/builders/GeneratingEquipment.aspx
[20] https://www.kentuckypower.com/builders/GeneratingEquipment.aspx

2.1.2 Procedures for Coordinated Studies of New or Materially Modified Interconnections

This section outlines the procedures for coordinated studies of new or materially modified interconnections that are summarized in the table below.

Table 2. Procedures for Coordinated Studies of New or Material Modified Interconnections

<table>
<tr><th>Region</th><th>DER</th><th>GC</th><th>EUC</th><th>TI</th></tr>
<tr><td>ERCOT</td><td rowspan="3">The procedures for initiating DER studies are located in Section 2.1.1.

The respective state and/or OpCo manage a screening process to determine the required level of study.</td><td>The procedures for coordinated interconnections within the ERCOT region can be found on the ERCOT website[21].

Small generator interconnections (10 MW or less) within the ERCOT region generally follow the DER process within that region. Please follow the procedures as indicated in the DER column.</td><td rowspan="3">Affiliate EUC studies are managed by the respective AEP OpCo. New Requesters should contact AEP Economic & Business Development (EBD)[22], while existing Requesters should contact their respective OpCo representative.

Non-affiliate EUC studies are outlined in each Requester’s agreement with AEP on file at the FERC’s eTariff website[23]. Communicate using the mailbox region in Section 2.1.1 for details.</td><td rowspan="3">Given the unique nature of TI, procedures for coordinated TI studies are managed on a case-by-case basis. The details are outlined in the respective Interconnection Agreements (IA) with AEP.</td></tr>
<tr><td>SPP</td><td>The procedures for studies within the SPP region can be found in Attachment V of the SPP Open Access Transmission Tariff (OATT), which is located on the SPP Governance website[24].</td></tr>
<tr><td>PJM</td><td>The procedures for studies within the PJM region can be found in the PJM Manual 14 Series on the PJM website[25].</td></tr>
</table>

2.2 Information Requirements

2.2.1 Data Required to Properly Study the Connection

The following subsections outline or direct Requesters to the information required in order for AEP to properly study the request.

---

[21] http://www.ercot.com/services/rq/re/
[22] https://aeped.com/
[23] https://etariff.ferc.gov/TariffBrowser.aspx?tid=3822
[24] https://www.spp.org/governance/
[25] https://www.pjm.com/library/manuals.aspx

2.2.1.1 Distributed Energy Resources

The Affiliate [i.e., AEP Operating Companies (OpCo)] or the Non-affiliate entities manage their respective data requirements for coordinated Distributed Energy Resource (DER) studies. These requirements are located on their respective websites. Requesters should engage with the respective Non-affiliate entity directly for their requirements. If it is determined that the request may have an impact to bulk transmission, including backfeed for short periods of time, a study for potential impact and additional data may be required.

2.2.1.2 Generation Connections

Generation Connection (GC) study data requirements are outlined in a form in *Appendix B.1* and upon completion should be communicated to the identified party within the form.

Additional or updated data, beyond RTE requirements, is also required once the facility has been declared ready for operation, including:

- Transmission line length, rating, positive and zero-sequence impedances based on final transmission line design.
- Final collector station relay one-line diagram.
- Final collector station relay (excluding inter-connect transmission line relays) settings, such that both parties must agree that coordination has been achieved before energization. Redundant high-speed protection schemes for generation facilities may be required to achieve coordination with Transmission protection schemes.

  Note: If the Requester's line relays differ from relays that AEP approved previously, backfeed will be delayed until the relays that AEP had approved are obtained and made available for the Requester's line terminal. Changes to settings and coordination of new settings will result in schedule delays and additional costs to the Requester.
- The Requester must supply the following materials to AEP before a generation facility is in operation: all final electrical one-line diagrams, equipment data, and schematic diagrams. Subsequent revisions affecting the generation must be documented with copies of the revised electrical one-line and schematic diagrams.
- Changes in ownership from the original Requester to another Requester or entity before energization may result in schedule delays and additional costs to the Requester. Any change in ownership must be communicated promptly to mitigate delays as much as possible.

2.2.1.3 End-User Connections

End-user Connection (EUC) study data requirements are outlined in a form in *Appendix B.2* and upon completion should be communicated to the identified party within the form.

2.2.1.4 Transmission Interconnections

Transmission Interconnection (TI) study data requirements are specific to each request. A form for initiating communication with AEP is provided in *Appendix B.3* and the respective System Interconnection Services (SIS) representative identified in *Section 2.1.1* will communicate any additional data requirements following AEP's detailed review of the request.

2.2.2 Procedures for Sharing Results of Studies and Data to be Included

At the completion of the respective study, AEP will share the results with the requesting party via the group or representative indicated and including the data illustrated in the following table.

Table 3. Sharing Methodology and Information to be Included in Studies

			GC[26]			EUC		
		DER	Feasibility	Impact	Facilities	Affiliate	Non-Affiliate	TI
Sharing Methodology	OpCo DER Representative	✓						
	RTO		✓	✓	✓			
	Affiliate OpCo CSAM[27] or E&BD[28]					✓		
	Interconnection Services Representative	✓[29]					✓	✓
Data Included in Study	Scope of Study	✓	✓	✓	✓	✓	✓	✓
	Assumptions	✓	✓	✓	✓	✓	✓	✓
	Local & Network Impacts	✓	✓	✓	✓	✓	✓	✓
	Stability Analysis				✓			
	Conceptual Scope of Work	✓	✓	✓		✓	✓	✓
	Functional Scope of Work				✓			
	Anticipated Costs	✓	✓	✓	✓	✓	✓	✓
	Anticipated Schedule	✓	✓	✓	✓	✓	✓	✓
	Appendices with Applicable Drawings, Diagrams, and Maps	✓	✓	✓	✓	✓	✓	✓

[26] For requests in the SPP region, SPP communicates Feasibility and Impact Study information, but requests Facilities Study information from AEP, which SPP communicates to the Requester.
[27] Customer Service Account Manager
[28] Economic and Business Development
[29] Interconnection Services representatives will be involved primarily when DER is connected to Non-affiliate Wholesale distribution facilities, while the AEP Affiliate OpCo DER Representative will manage connections to AEP Affiliate distribution facilities.

2.3 Coordination with Other Codes, Standards, and Agencies

The information contained in this document is supplemental to and does not intentionally conflict with or supersede the National Electric Code (NEC), National Electric Safety Code (NESC), *IEEE*[30] *1547*, *IEEE 1547.1*, *IEEE P2800*, *IEEE P2800.1*, or such federal, state and municipal laws, ordinances, rules, regulations or tariffs as may be in force within cities, towns or communities.

It is the Requester's responsibility to conform to all applicable and current requirements. The Requester's responsibility begins at the point of interconnection (POI) described in the established agreement.

2.4 Indemnification

The Requester, for itself, its successors, assigns and subcontractors will be required to pay, indemnify and save AEP, its successors and assigns, harmless from and against any and all court costs and litigation expenses, including legal fees, incurred or related to the defense of any action asserted by any person or persons for bodily injuries, death or property damage arising or in any manner growing out of the use and reliance upon the information provided by AEP. Reliance upon the information in this document shall not relieve the Requester from responsibility for the protection and safety of the general public within the Requester's facilities as defined in the executed agreement.

[30] Institute of Electrical and Electronics Engineers

3.0 Planning

The following subsections outline the requirements associated with the planning phase of a typical project, including standard connection types, in-line switching, design information, configurations of connected generation, siting and environmental requirements.

3.1 Connection Types and Diagrams

The following subsections illustrate standard connections to the AEP system for EUC and GC connection types. In addition, the diagrams reference detailed design requirements where applicable.

Figure 2. Legend

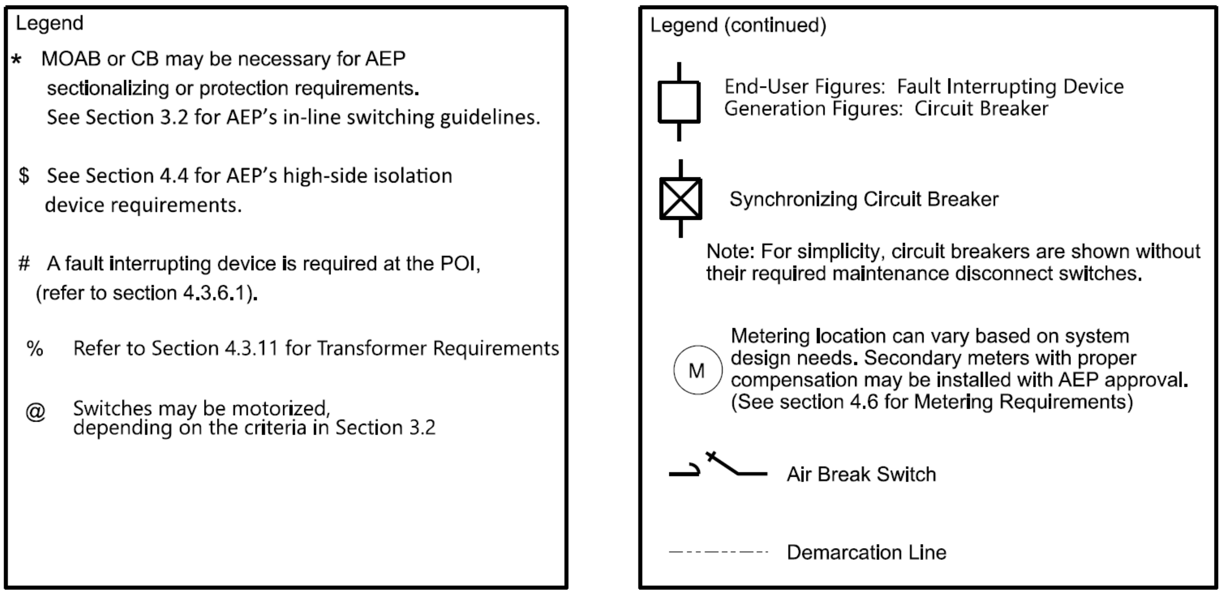


Figure 3. End-user Connection Types

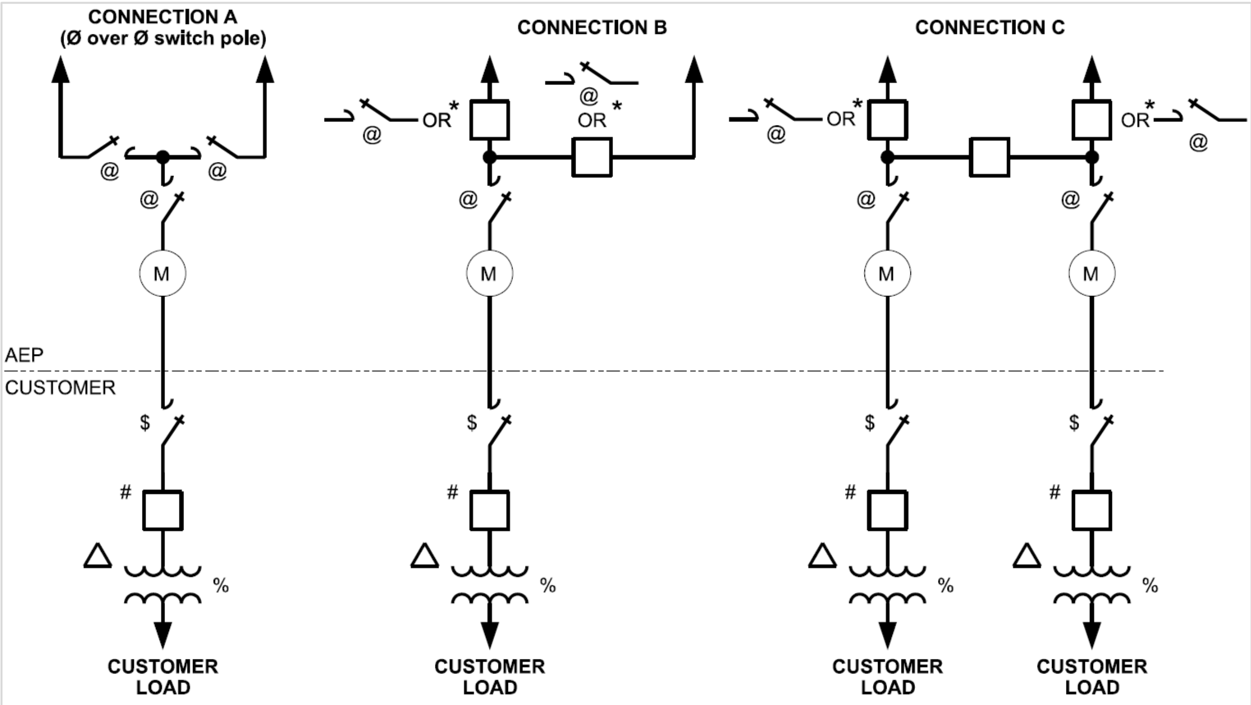


Figure 4. End-user Connection Types

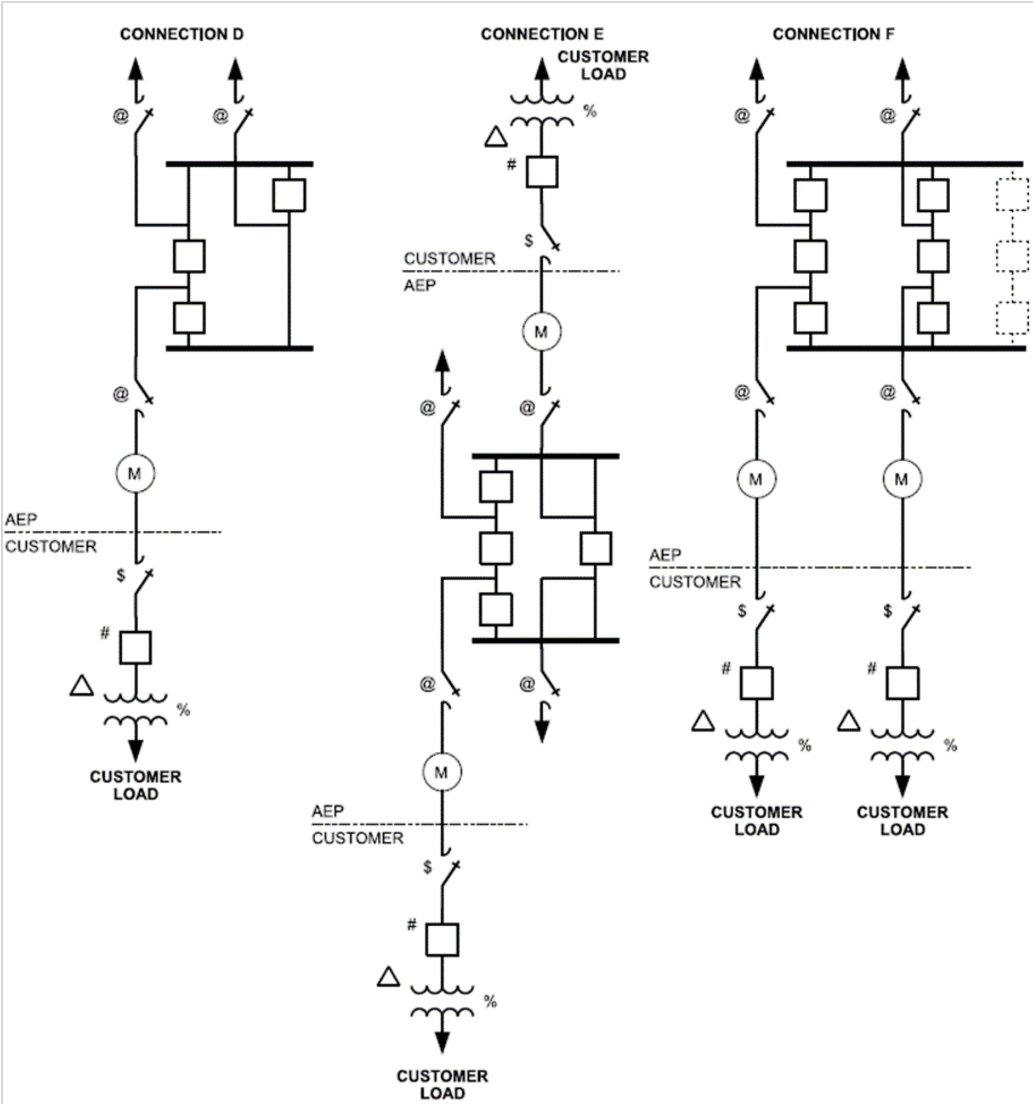


Figure 5. End User Connection Types

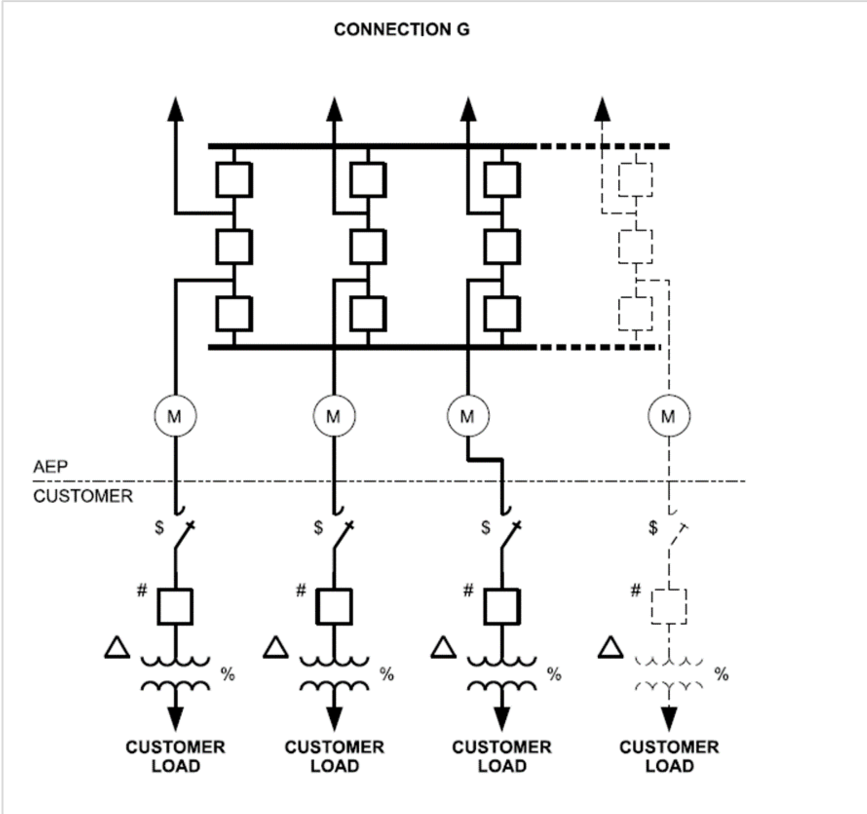


Figure 6. Generation Connection to an Existing Station Bus

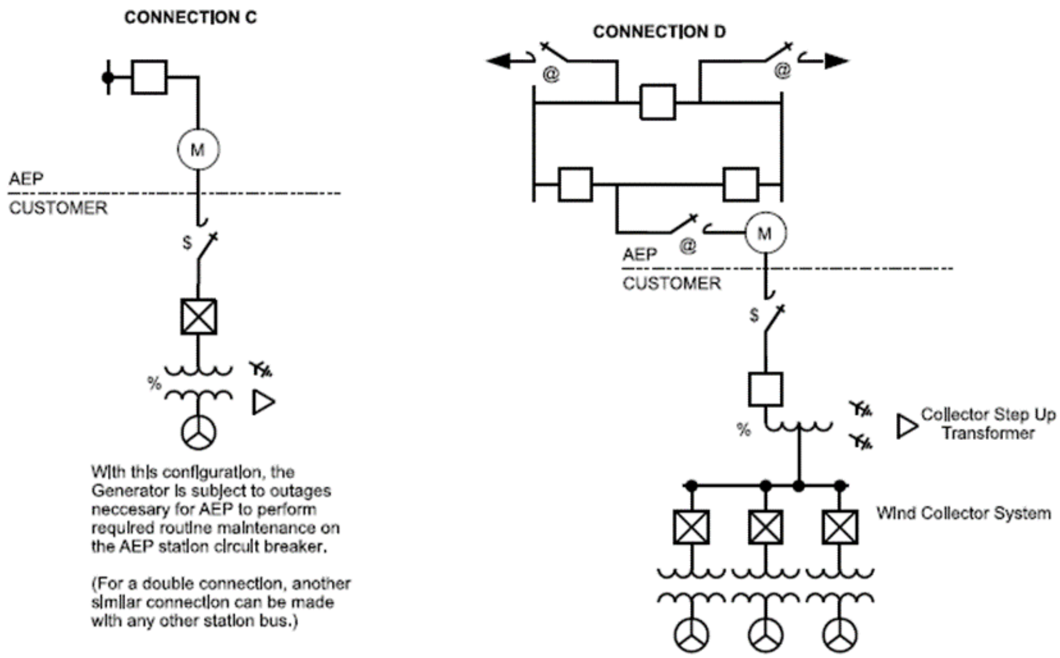


Figure 7. Generation Connection to an Existing Transmission Line

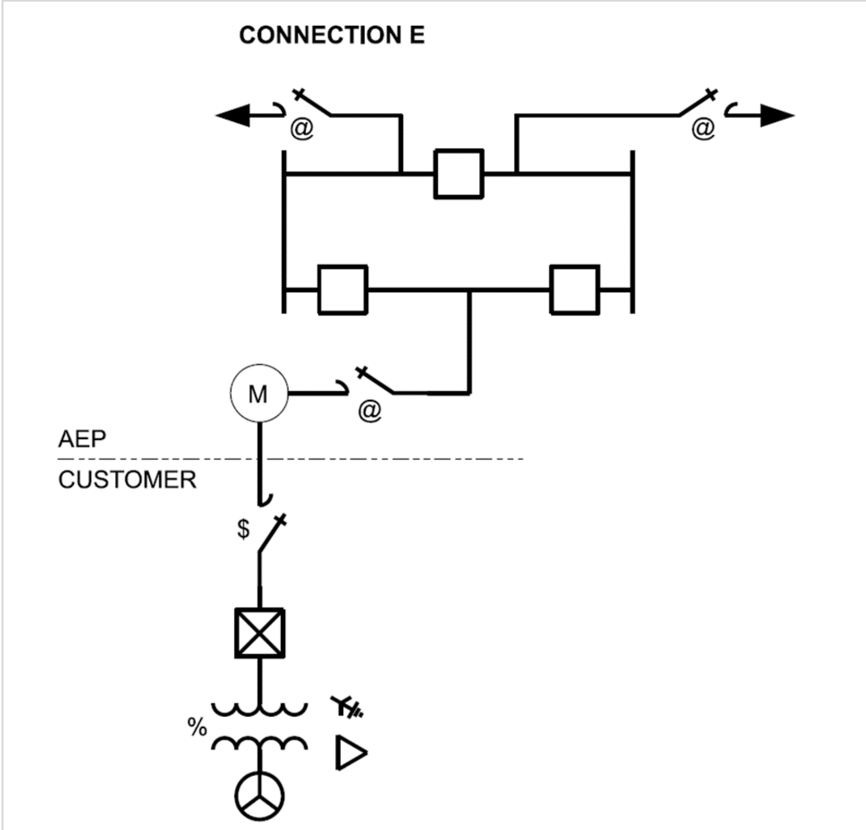
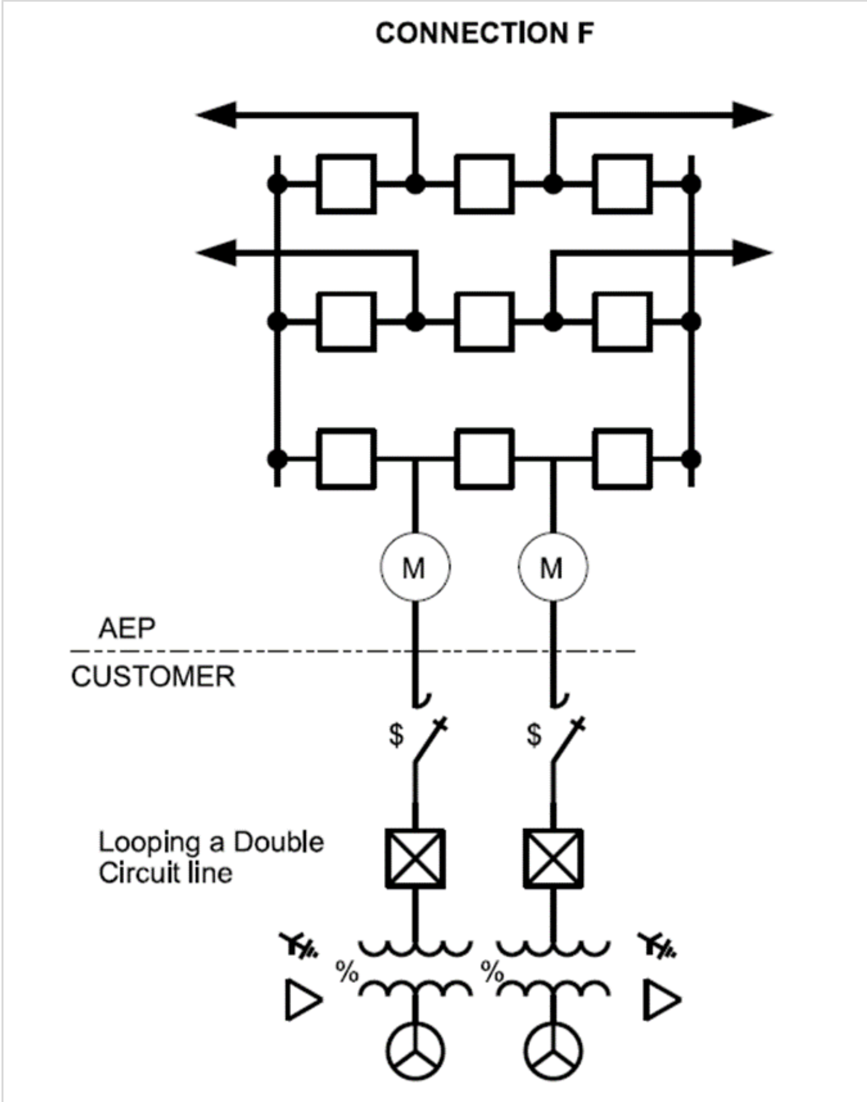


Figure 8. Generation Double Connection to an Existing Line(s)



3.2 Transmission Switching Guidelines

Any connection to AEP will require, at a minimum, motor operated, Supervisory Control and Data Acquisition (SCADA) controlled line disconnect switches, commonly referred to as motor operated air break (MOAB) switches. The only exceptions to this minimum requirement where switches are not required are the following situations:

- The connection established to serve load is temporary and is required for a period less than a year.
- The topography of the tap location is such that the tap is not accessible by road, in which case the in-line switches could be placed elsewhere in a more accessible location.
- The tapped in-line connection is required temporarily under emergency system conditions.

SCADA control and monitoring is required for all in-line sectionalizing unless acceptable justification for manual control exists. Automatic motor operated controls can be added to in-line switches, when justified, to minimize the time required for restoration following a failure of the AEP supply line.

The factors considered when determining whether a load connection is radial or looped MOAB or CB application for in-line switching include, but are not limited to:

Safety & Health	SAIDI performance
Total load magnitude	Criticality of load and customer/community impact
Restoration time	Operational flexibility
MVA-mile calculations	Existing system configurations
FOI calculations for MOABs	Consideration regarding feasibility of maintenance
MPOI calculations for CBs	Area outage statistics

The FOI and MPOI calculations are structured as follows:

Equation 1

$$FOI = L_f \times Miles\ of\ Exposure \times P_f$$

Equation 2

$$MPOI = L_f \times Miles\ of\ Exposure \times \left(P_f + M_f\right)$$

where L_f is the peak load (MW) directly jeopardized by the forced outage of the line, Miles of Exposure is the number of line miles between two existing automatic sectionalizing devices (including taps). P_f is the Permanent Forced Outage Rate (Outages per Year, per Mile), and M_f is the Momentary Forced Outage Rate (Outages per Year, per Mile).

AEP manages the specific minimum thresholds of which FOI or MPOI calculations support the installation of auto-sectionalizing MOAB switches or circuit breakers, respectively. AEP also manages the specific minimum thresholds for determining the requirements on when to loop a radially-fed load.

The figures in *Section 3.1* illustrate some basic connection configurations and requirements for facilities below 200kV.

Circuit Breakers are required to connect to the AEP system at or above 200kV.

For more information on isolation and fault interrupting devices, please reference *Sections 4.3.1 and 4.3.2*.

3.3 General Design Information

Nominal voltages on the AEP system are 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, 115kV, 69kV, 46kV, and 34.5kV. The Requester must contact the appropriate entity as shown in *Section 2.1.1* for information on the specific circuit(s) presently serving or available to serve their facility.

For AEP's Planning Criteria, including voltage criteria, please see AEP's *FERC 715* filings on AEP.com[31]. The filings are separated by regional transmission entity (RTE) and are named as follows:

[31] https://aep.com/requiredpostings/AEPTransmissionStudies

- Transmission Planning Reliability Criteria-AEP PJM
- Transmission Planning Reliability Criteria-AEP MISO
- Transmission Planning Reliability Criteria-AEP SPP
- Transmission Planning Reliability Criteria-AEP ERCOT

Transmission Planning will design solutions based on results of power flow analysis in accordance with AEP's planning criteria. Solutions will identify minimum required current carrying capability and establish facility ratings based on AEP's procedure for determining facility ratings.

The Requester will own the breaker(s), protection and control for all equipment at its facility. The Requester is responsible for protection of its facilities from all abnormal conditions occurring on the transmission system. When the Requester's facilities are connected to AEP, the Requester must install, operate, and maintain all facilities AEP requires for safe operation and without cost to AEP. The Requester must install, operate, and maintain its facilities at all times in conformance with generally accepted utility practice and must comply with applicable National Electrical Code, National Electrical Safety Code, local codes, regional transmission entity (RTE), North American Electric Reliability Corporation (NERC) Reliability Standards, and AEP service standards.

Under certain conditions, AEP may operate for a period outside the defined voltage ranges documented in AEP's *FERC 715* filings. The Requester must provide voltage-sensing equipment required to protect its equipment during abnormal voltage operation.

If the Requester's supply voltage requirements are more restrictive than specified above, the Requester should consider adding appropriate voltage regulation equipment in its facility. The Requester is responsible for voltage regulation at the point of power consumption.

The Requester will change their facility or equipment as AEP or an RTE requires to comply with future changes in the transmission system. AEP will provide reasonable notice to the Requester, before the due date, when changes to their facilities are required. The Requester is responsible for the costs of any additions, modifications, or replacements to their facilities that are necessary to maintain or upgrade such facilities consistent with applicable laws and regulations, applicable reliability standards, and good utility practice.

The Requester will design the generating facility to maintain a composite power delivery at continuous rated power output at the POI of the generator substation, at a power factor within the range of 0.95 leading to 0.95 lagging, unless AEP has established a different power factor range that applies to all generators in the control area on a comparable basis. This power factor range standard must be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two.

The NERC Reliability Standards state that distribution entities and customers connected directly to the transmission system should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission system. AEP interprets close to unity power factor to mean that the connected load should not fall below a 0.95 lagging power factor. Power factor penalties are applied based on local jurisdictional terms and conditions.

Switched shunt capacitors generally provide an effective means of controlling the power factor of a Requester's facility. However, several considerations should be addressed in applying capacitors. They include:

- Transient voltages due to capacitor switching
- Voltage amplification due to resonance conditions

Requesters should work with a qualified consultant to review the specific application and provide recommendations for controlling these occurrences.

Requester's equipment should, at a minimum, comply with the ITIC (Information Technology Industry Council)/CBEMA (Computer & Business Equipment Manufacturer's Association) curve for voltage sag ride-through performance.

See *Section 6.12* for power quality requirements.

3.4 Generation Configurations

GSU Configurations

AEP has established generator step-up (GSU) transformer requirements as shown in *Section 4.3.6* . The final decision as to the requirements for each installation will be made depending on:

- Requester's electrical location of the generator
- Existing electrical facilities
- Rating of existing electrical equipment and generators connected to the system, available short circuit contributions, and other important factors

Induction Generators

Depending on the generator size, reactive power demands of induction generators can pose transmission system problems. The interconnection study process may identify the need for additional equipment that can keep negative impacts to the transmission system from occurring.

Inverter Systems

The reactive power requirements of inverter systems are similar to induction generators. Therefore, the general requirements discussed in the previous section apply. Refer to *Section 6.12* for additional considerations.

3.5 Siting & Environmental Requirements

3.5.1 Transmission Facilities Siting Requirements

The Requester will consult with AEP while evaluating a siting location for the interconnection facilities that the Requester will transfer to AEP during the interconnection process.

This activity must occur during the planning process and before real estate acquisition. This requirement applies to the option to build (OTB) process for facilities that the Requester will transfer to AEP and for acquiring real estate and right-of-way (ROW) that the Requester will turn over to AEP as part of an interconnection project. This siting requirement section is applicable to all Generation Connections (GC), End-User Connections (EUC), Transmission Interconnections (TI), and Distributed Energy Resources (DER).

Typical siting specifications include adherence to state regulatory filing and application requirements in coordination with a line route or substation siting study for a proposed interconnection facility. This documentation supports the environmental permitting process, landowner negotiation, and requests from local officials as well. A conventional line route or substation siting study describes the alternatives considered, provides a comparative analysis of potential environmental and land use impacts, and a rationale for the selection of the proposed site and/or transmission line route. The siting study should describe the input collected from local officials, state and federal permitting agencies, and the local community relative to the site's suitability for the proposed facility.

Refer to the *Standards and Expectations for Siting, Real Estate, Right-of-Way, and Environmental Permitting for Transmission Interconnection Projects* for more information. The Requester is expected to read and understand the expectations described in this document in the project's early stages.

3.5.2 Environmental Requirements

The Requester must work with AEP during the interconnection process to ensure that any facilities, land, or interests that the Requester will transfer to AEP comply with all applicable environmental requirements, law, and regulations. Planning and coordination will occur before any real estate acquisitions take place.

3.5.2.1 Option to Build

AEP must review any permits and mitigation agreements with regulatory agencies before submittal to ensure consistency with AEP's processes and long-term facility management requirements. Compliance requirements apply to real estate acquisition and ROW that the Requester will transfer to AEP as part of an interconnection project. Compliance with these requirements can affect site location, design, and feasibility. Environmental specifications may vary by location and governing authority.

3.5.2.2 Required Documentation and Permits

The Requester is responsible for maintaining documentation related to the laws and regulations compliance. The environmental requirements section of the *Standards and Expectation for Siting, Real Estate, Right-of-Way and Environmental Permitting for Transmission Interconnection Projects*[32], and compliance to all applicable laws and regulations apply to all GC, EUC, IC, and DER.

Typical environmental permits include, but are not limited to, Army Corps of Engineers Section 10/404 (or state authorized program), *State Section 401 Water Quality Certification*, storm water general permits, and floodplain permits. Environmental requirements include adherence to the government authority's laws as well as the environmental requirements resulting from coordination of a line route or substation siting study for a proposed interconnection facility. Associated environmental studies that support the environmental permitting effort and siting study should

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32 https://aep.com/assets/docs/requiredpostings/TransmissionStudies/docs/2020/StandardsforsitingREROWandEnvironmental.pdf

include documentation collected from local officials as well as information gathered from state and federal permitting agencies relative to the site's suitability for the proposed facility.

The Requester must provide engineering and compliance documentation for environmental permits and all applicable laws and regulations before real estate is transferred to AEP, including support that the real estate is sufficient to comply with all laws and regulations for post-construction water management. For example, station pad design must accommodate post-construction storm water features in compliance with government authority's laws and regulations.

Refer to the *Standards and Expectations for Siting, Real Estate, Right-of-Way, and Environmental Permitting for Transmission Interconnection Projects*[33] for more details. The Requester is expected to read and understand the expectations in this document during the project's early stages and inform their engineering team of the requirements, laws, and regulations.

33 https://aep.com/assets/docs/requiredpostings/TransmissionStudies/docs/2020/StandardsforsitingREROWandEnvironmental.pdf

4.0 Design

The following subsections outline the requirements associated with the design phase of a typical project, including station, equipment, protection, SCADA, metering, telecommunications, station service, and line design.

4.1 Station Design Requirements

4.1.1 Access Plan Requirements

For AEP interconnection facilities to be located on Requester's property, Requester shall provide an access plan to AEP for review and approval. Such access plan is to document AEP access privileges to interconnection facilities on Requester's property, including, but not limited to, metering equipment, RTU equipment, telecommunications network equipment, and fiber optic facilities. The access plan described above shall be approved by AEP and implemented by Requester prior to AEP placing the interconnection facility in service.

4.1.2 Grounding and Safety Issues

This section provides guidance on design and analysis of ground grids in substations that AEP will own and operate, and a Requester's ground grid that will be connected to or in close proximity to AEP's ground grid. Where the Requester's grid is connected to or in close proximity to AEP's ground grid the Requester shall coordinate with AEP and comply with AEP ground grid design requirements as detailed in the latest revision of AEP standards SS-313000 Station Ground Grid Design Guide, SS-311000 Grounding Application Guide, and IEEE 80. For any conflict among documents, contact the Substation Engineering Design Standards subject matter expert.

Contact the AEP project manager to obtain ground fault values and clearing times for AEP facilities. When Requester's grid is connected to or in close proximity to AEP's facilities the Requester must provide AEP with design drawings, analysis files that are compatible with AEP standards, and material lists for the proposed substation ground grid. Ground grid connections between AEP facilities and the Requester's facilities must be designed and installed in compliance with AEP standards.

4.1.3 Substation Fence

Where Requester's fence will tie to an AEP fence the Requester shall notify AEP of the design intent and coordinate the tie point and the Requester shall also comply with the grounding requirements as detailed in section 4.1.2.

Fencing that encircles AEP owned equipment must comply with the latest revision of AEP standard *SS-250100 Station Fence Guideline*, *SS-250500 Substation Fence Specification,* and National Electrical Safety Code (NESC) requirements.

4.1.4 Substation Bus Design Requirements

Where Requester is interfacing with AEP station bus, the Requester shall match heights and phase spacing of AEP facilities at the point of demarcation. AEP shall provide location for connection to Requester. The preferred method of making connections to AEP equipment is through flexible stranded conductor.

Measures should be taken to ensure the interface between Requester and AEP does not result in a limiting series element.

4.1.5 Station Shielding

Where AEP equipment is located in the same fence as Requester's facilities the lightning protection system must be designed at a minimum inaccordance with the latest version of *SS-499 Lightning Protection Application Guideline*. The Requester will perform a shielding study and the Requester will submit design drawings and analysis files to AEP for comment. The Requester must provide locations and attachments for required static wires that will be terminated on the AEP or or Requester's facilities. AEP will determine loading requirements on a case-by-case basis.

4.2 Substation Structures

Structure Loading

In situations where one or more of the Requester's structures is supporting strain bus, rigid bus, conductor, or shield wires that are connected to AEP structures, those structures must be designed for strength and deflection to meet AEP's structural loading criteria found in AEP *SS-720000 Specification for Substation & Switching Station Structural Steel Design & Fabrication Standard*. The Requester shall coordinate with AEP on tensions & fault loads for these structures.

4.3 Equipment

4.3.1 Fault Interrupting Devices

A fault-interrupting device must be the initial connection point (immediately after the isolation device) inside the Requester's substation. It is the Requester's responsibility to protect all of their equipment and prevent faults on their system from affecting AEP's facilities and other customers. The Requester may need to install and pay for additional station facilities to establish their desired service, or to establish a looped transmission line extension. From an electrical service point of view, it is most desirable for a Requester to locate their substation facilities near an AEP transmission line or substation. If a radial line (longer than 1 mile) is required from the tap point on a transmission line to the Requester's facility, a breaker may be required at the tap location in addition to the breaker at the requester's facility. This specification will be determined on a case-by-case basis. It is solely AEP's discretion to allow variances to this practice.

If a Requester proposes to use a fuse as the interrupting device, see Section 4.3.6.2.

AEP does not allow the installation of a MOAB ground switch combination on the high side of transmission/step-down transformers unless a special need or situation warrants review. All new connections or material modifications to existing connections must comply with the diagrams and requirements shown in *Section 3.1*.

Requester-owned load serving transformers located within the same fenced station as AEP Transmission circuit breakers, do not require Requester-owned fault interrupting devices when connected between two AEP Transmission circuit breakers (i.e., breaker and a half or ring bus designs). Requester-owned load serving transformers within the same fenced station connected directly to an AEP bus will require a Requester-owned interrupt device. In the rare occasion where non-AEP Requester-owned equipment is located within the same fenced station as AEP Transmission equipment, an agreement is required to define maintenance, operations, and NERC Standard compliance responsibilities.

4.3.2 Isolation Devices

The Requester must provide a readily accessible, lockable, visible-break isolation device as the first device connection inside the Requester's station.

The Requester's isolation device may be included in AEP's *Switching Order System Procedure* as necessary. Access to the Requester's isolation device must be provided if clearance is necessary on Requester facilities.

4.3.3 Equipment Ratings

AEP establishes facility and equipment ratings requirements during a project's planning phase. In accordance with *Section 4.1.5 Station Shielding*, the Requester must complete insulation coordination studies and requirements.

4.3.4 Circuit Breakers and Switches

Before construction, the Requester must provide AEP with the characteristics of the units to be installed for evaluation as identified in *Section 3.1* for load connection types/diagrams and *Section 3.2* for transmission switching guidelines. The manufacturer must provide the maximum capability values of the circuit breaker/switcher as tested and not IEEE preferred rating values.

AEP will work with the Requester to determine high-speed reclosing (HSR) coordination times. Typical HSR coordination times are listed in the table below.

Table 4. HSR Coordination Times

System Voltage (kV)	Trip Close Time (Cycles)
765	30
345	24
230	21
161	18
138	18
69	9

4.3.5 Line Traps

Load Connection Requirements

Line traps may be required with load connections. Carrier signals can be degraded by transformers and/or tapped loads that are electrically located at multiples of the quarter wavelength of the carrier frequency on the line. It is not practical to predict with accuracy whether newly tapped load will create this condition. The Requester will be responsible for costs necessary to ensure that the new delivery point (DP) does not degrade the power line carrier signal(s) or protection scheme.

This cost may require installing a line trap tuned to the carrier frequency on the appropriate phase at the point of connection. The Requester can install this line trap in advance, or wait to determine whether a line trap is necessary at the time of energizing the newly tapped station. However, if the Requester waits to install the line trap, and it is later determined that the new installation has degraded the carrier signal(s), then the DP will be de-energized until a line trap is installed to eliminate the source of carrier signal degradation.

4.3.6 Transformers

4.3.6.1 Voltage and Impedance Matching

The Requester is responsible to ensure all de-energized tap changer settings available will not be detrimental to AEP system or their own system. De-energized tap changer (DETC) ratings must match that of AEP transformers in connecting substations. Additionally, transformer impedance must match that of AEP's transformer fleet when paralleling. These requirements are in place to prevent circulating currents and the consequential overloading of AEP facilities.

4.3.6.2 Requester High Voltage Transformer Fusing Rerquirements

If a Requester proposes to use a fuse as the interrupting device for a high voltage transformer, the fuse must have a total clearing time for a fault immediately downstream of the fuse less than the minimum clearing time of AEP upstream protection and interrupting devices. The AEP minimum clearing time for this scenario is typically 5.0 cycles. The requester's fuse must fully clear the fault so that the following AEP reclose attempt can be successful to restore the circuit and other AEP customers. **AEP's Protection and Control Engineering (PCE) Department must pre-approve the Requester's proposed fuse size.** Note that fuses will not be acceptable if the Requester has generation sources as part of their facilities. In addition, if generation sources are added to Requester facilities later, the fuses must be replaced with an interrupt device that can be operated from transfer trip equipment as necessary.

4.3.6.3 Transformer Winding Design

All EUCs must provide a delta connected winding on the AEP line terminal side of the transformer. All GCs must provide an effectively grounded connection on the AEP line terminal side of the transformer. The GC's transformer must remain effectively grounded on the AEP line terminal side of the transformer even when the transformer is unloaded.

4.4 Protection Systems

4.4.1 System Protection and Coordination

4.4.1.1 Basic Protection System Design for Interconnect Projects

There are two basic protection systems that could be implemented on Requester interconnections: bus protection and line protection. This section describes both systems. The system that is chosen depends on the distance between the Requester and AEP, whether ground grids are tied together, and whether the Requester has a generation source. Generation sources can come from primary generation sources, emergency generation sources, or ties to alternate sources of power.

- **Bus Protection System**
  - This system is generally used when the interconnection stations are adjacent to each other and the ground grids are tied together. AEP requires redundant three-phase current circuits from each Requester interface (overlapping the Requester protection zone) to complete the bus protection zone(s). Interface cabling for trip, control, and status signals will depend on the Requester's facility configuration and whether the Requester has generation sources.

- The interface connection must be within the AEP protection zone and isolated by AEP protection devices (Interrupt devices from both AEP and the customer may need to be operated depending on customer generation sources). The Requester is not required to have protection devices for the interface connection when this system is used. All equipment downstream of the Requester interrupt device will be in the Requester protection zone and isolated by Requester protection devices.

- **Line Protection System**
  - **Step Distance Protection System**
    - This system is used when the interconnection stations are not adjacent to each other and the Requester has no generation sources.
    - The interface line connection must be in the AEP protection zone and isolated by AEP protection devices. The Requester is not required to have protection devices for the interface line connection when this system is used. All equipment downstream of the Requester's interrupt device will be in the Requester protection zone and isolated by Requester protection devices.
    - The Requester should understand that when this protection system is used, the AEP protection devices will have high-speed operation for all faults up to and including a portion of the Requester transformer. The AEP total clearing time must allow time for the Requester protection devices to operate and trip the Requester interrupt device for proper isolation and targeting, even though the AEP interrupt device can still trip and isolate the customer for this event.

      Following the initial isolation from AEP, AEP interrupt devices will be allowed to reclose automatically and re-establish power up to the Requester's interrupt device. Note that the AEP protection devices and interrupt devices could clear the fault in five (5) cycles. Therefore, the Requester relay device or fuse must operate faster than the AEP clearing time for the interface line connection to successfully re-energize the Requester's connection and possibly re-energize other AEP customers. Therefore, if the Requester applies a fuse, it must have a total clear time faster than five (5) cycles for a fault immediately downstream of the fuse.

      AEP's Protection and Control Engineering (PCE) Department must pre-approve the Requester's proposed fuse size.

  - **Pilot Protection System**

    Pilot protection systems are required on Bulk Electric System (BES) facilities. AEP reserves the right to apply pilot protection systems on non-BES facilities.

    AEP reserves the right to apply dual pilot protection systems (two pilot protection systems with independent communication paths) to either BES or non-BES facilities as necessary for either coordination or stability.

    - **Current Differential Line Protection System**

      The current differential line protection system is the preferred pilot protection system when the interconnection stations are not adjacent to each other and the Requester has generation sources.

The interface line connection must be in a shared protection zone between AEP and the Requester. The Requester will purchase and install interface line protection devices according to AEP requirements (see below). All equipment on the Requester side of the Requester interrupt device must be in the Requester protection zone and isolated by Requester protection devices.

- **Directional Comparison Blocking Protection System**

  The directional comparison blocking (DCB) protection system is the alternate pilot protection system when the interconnection stations are not adjacent to each other and the customer has generation sources. The DCB protection system may be required when the Requester connects into AEP facilities that have existing DCB protection systems or power line carrier (PLC) protection communications are required for new facilities. The interface line connection must be in a shared protection zone between AEP and the Requester. The Requester will purchase and install interface line protection devices according to AEP requirements (see below). All equipment on the Requester side of the Requester's interrupt device must be in the Requester's protection zone and isolated by Requester protection devices.

- **Breaker Failure Protection System**

  Breaker failure protection systems are required on Bulk Electric System (BES) facilities. For non-BES facilities, AEP reserves the right to require installation of breaker failure protection systems at the Requester's facility and/or at the AEP facility.

- **Anti-Islanding Protection**

  If the Requester's facility contains generation sources, then the Requester must have an anti-islanding protection system. If an anti-islanding system is not viable, then AEP reserves the right to require installation of a direct transfer trip (DTT) system between the AEP facility and the Requester facility.

4.4.1.2 Coordination of Protective Systems

NERC standards require that protective systems be coordinated among operating entities. These standards require transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. In addition, transmission and generator operators must coordinate with appropriate entities when new protective systems are installed, or when existing protective systems are modified. It is expected that any data exchange necessary to meet the obligations of the NERC Standards will be accomplished before any protection systems can be placed in service. Refer to *Section 2.1.1* for details.

4.4.1.3 System Protection Equipment Requirements

It is AEP policy to apply fully redundant protection systems at 200kV and above. This includes batteries, DC panel-boards, trip coils, high-speed protection systems, communication paths, and instrument transformers (dual secondary windings on one set of potential devices is acceptable). Prior to the design phase, the Requester and AEP must reach a mutual agreement as to the redundancy requirements, type, model numbers, and firmware version of equipment related to the proposed pilot relaying scheme to ensure proper operation and equipment compatibility.

The Requester must install protective devices (relays and circuit breakers for example) and synchronizing equipment that AEP requires. The protective devices may differ between installations.

The Requester must submit relay one-line drawings of its interconnection equipment to AEP for review. AEP will assess the protection and remote monitoring/control functions illustrated in the drawings. The Requester must make changes that AEP requires prior to final issue. The Requester must provide final copies of the revised drawings to AEP. AEP will review only the portions of the drawings that apply to protection and remote monitoring/control that affect the AEP system. To aid the Requester, AEP may make suggestions on other areas, but AEP will not assume responsibility for the correctness pertaining to the Requester's system.

The Requester is responsible for their system's stability and providing adequate facilities so that critical fault clearing times are met.

The Requester must not connect to AEP's system until AEP gives consent. AEP reserves the right to inspect the Requester's facility and witness equipment or devices testing associated with the interconnection. Additional operating procedures may be included in the Interconnection Agreement (IA). Refer to *SS-451001 AEP Protection Requirements for Connecting to the AEP Transmission Grid* for more information.

4.4.2 Control Cable

AEP uses shielded control cable with both ends grounded. The color codes of control cable for AC or DC circuits must be constructed to match table E-2 of ICEA S-73-532, NEMA WC-57 (black, red, blue, orange, yellow, and brown, for example). The color codes of AC power cables must be constructed to match table E-1 of ICEA S-73-532, NEMA WC-57: black, white, red, and green. If the Requester's interconnect cables do not match these codes, the Requester must wrap each interconnect control wire with the appropriate color code tape. Refer to *SS-480001 Design and Wiring Guide* for more details.

The AEP preferred control cable demarcation point is at the AEP substation fence between AEP's substation yard and Requester's substation yard. It is the Requester's responsibility to supply material and labor for cables installed from their equipment to the demarcation cabinet. AEP is responsible for supplying material and labor for cables installed between AEP's equipment and the demarcation cabinet. Before project construction, AEP must approve any deviations from its preferred control cable demarcation point.

4.4.3 Disturbance Monitoring Requirements

AEP requires disturbance monitoring on all generation resources connected to AEP and all distribution connected generation (single unit or aggregated) that is 5 MW and above connected to a single distribution transformer bank. Disturbance monitoring includes fault recording, sequence of events recording, and phasor measurement unit recordings. AEP is solely responsible for determining exclusions to this requirement on a case-by-case basis.

The disturbance monitoring equipment (DME) location will depend on the generation resource's configuration. The Requester must submit their facilities' relay one-line diagrams to AEP. If sufficient disturbance recording data cannot be collected at the AEP interface station, the Requester must supply monitoring equipment that will support the necessary disturbance monitoring data. AEP must approve the Requester's data format. AEP will identify the required monitoring locations based on the Requester's relay one-line diagram. Locations could include monitoring each unit in a conventional generation resource and each feeder in a renewable generation resource. In addition:

- The Requester must replace legacy equipment if they cannot provide data in the requested format.
- All DME must be equipped for time synchronization.
- If AEP requires DME installation in the Requester's facilities, the Requester must provide communication facilities so that AEP can collect disturbance monitoring data remotely.
- AEP's monitoring requirements do not reduce the Requester's obligation to meet all NERC disturbance monitoring requirements.

4.5 SCADA Requirements

4.5.1 Data Requirements

Telemetry and status information is required from interconnected facilities rated at 5 MVA or higher in order for AEP to fulfill its real-time monitoring and assessment obligations. The primary means AEP will use to obtain this data will be Inter-control Center Communications Protocol (ICCP) communication links already in place with the RTE. AEP will request the specific data points from the RTE in which the Requester's facility is located.

If a GC Requester is connecting to AEP-owned Transmission facilities and is not able to provide all necessary data to the RTE, AEP will work with the Requester to establish an alternate means of obtaining the necessary real-time operational data until the RTE ICCP link can be established. In cases where fiber-optic facilities described in *Section 4.7* are put in place for reasons other than operational data exchange, AEP may choose to establish a serial connection over those facilities based on the *SS-500000 AEP SCADA RTU Requirements for Transmission Interconnection Facilities*. The term and method for all data exchanges will be outlined in the Interconnection Agreement.

Requesters that represent or serve DER connections may have additional real-time operational data obligations to meet. These obligations are currently evolving — AEP will work with these Requesters to ensure AEP and RTE requirements are met.

Sections 4.5.2 and *4.5.3* below detail the specific telemetry and status points required from interconnecting facilities. Note that not all of the points listed below are universally required. Certain points only apply to Requester facilities of a certain type as designated. The final points list will be engineered for each interconnecting facility based on the design and capabilities of that facility.

AEP Transmission will not install an RTU on the premises of interconnecting facilities (substations) it does not own and will not operate Requester's equipment at such locations except in unique cases where a specific detailed agreement to do so is in place. Requesters are responsible for providing facilities for acquiring real-time operational data from equipment they own and will be responsible for providing that data to AEP Transmission and the appropriate RTE.

4.5.2 Telemetry

Analog telemetry from interconnecting facilities includes power flow and voltage measurements needed by AEP Transmission to perform accurate state estimation and contingency analysis required for situational awareness for reliable operation of the transmission grid.

Table 5. Transmission Line Measurements

Voltage per phase for Requester-owned end of each transmission line	kV
MW for Requester-owned end of each transmission line	MW
MVAR for Requester-owned end of each transmission line	MVAR
MVA for each Requester-owned end of each transmission line	MVA

Table 6. Generator Collector Transformer Measurements

Voltage per phase for each winding of each transformer [wind/solar]	kV
MW for each side of each transformer [wind/solar]	MW
MVAR for each side of each transformer [wind/solar]	MVAR

Table 7. Generation Measurements

Generation gross bidirectional MW [each thermal-powered unit]	MW
Generation gross bidirectional MVAR [each thermal-powered unit]	MVAR
Generation station use MW auxiliary (per aux transformer) [thermal-powered units]	MW
Generation station use MVAR auxiliary (per aux transformer) [thermal-powered units]	MVAR
MW for each collection feeder [wind/solar]	MW
MVAR for each collection feeder [wind/solar]	MVAR

Table 8. Generator Shunt Devices / Reactive Quantities

MVAR for each shunt device (capacitors and reactors)	MVAR
Dynamic MVAR capability at the current MW generation amount (each dynamic reactive controller)	MVAR
Voltage set point (each dynamic reactive controller)	kV
Power factor set point (each dynamic reactive controller)	pf

Table 9. Resource Availability for Injection for Real or Reactive Power

Number of wind turbines or solar inverters connected to transmission system (entire generating facility)	# of units
Number of wind turbines or solar inverters connected to transmission system (per collection feeder)	# of units
Number of wind turbines or solar inverters out of service and unavailable (per collection feeder)	# of units
Number of wind turbines or solar inverters with communications failure and unknown availability (per collection feeder)	# of units
Amount of energy remaining [storage]	MWh

4.5.3 Status

In addition to real-time telemetry values, the operational status of key interconnected facilities must be available to AEP Transmission in real time.

Table 10. Transmission Line Status

Breaker Status for requester end of each transmission line	OPEN/CLOSED
Circuit Switcher / Line Switch Status for requester end of each transmission line	OPEN/CLOSED

Table 11. Generation Facility Status

Generation Breaker Status [Thermal-Powered Units]	OPEN/CLOSED
Auxiliary Breaker Status [Thermal-Powered Units]	OPEN/CLOSED
Transformer High Side Breaker and/or MOAB Status [Wind / Solar]	OPEN/CLOSED
Collection Breaker Feeder Status, Each Feeder [Wind / Solar]	OPEN/CLOSED
Bus Tie Breaker Status	OPEN/CLOSED
Automatic Voltage Control	DISABLED/ENABLED
Black Start Availability	OFF-LINE/AVAILABLE

Table 12. Generator Reactive Device Status

Shunt Device (Capacitor, Reactor) Breaker Status	OPEN/CLOSED
Dynamic Reactive Controller Status	DISABLED/ENABLED
Dynamic Reactive Controller Operation Type	MANUAL/AUTO
Dynamic Reactive Controller Mode	VOLTAGE/POWER FACTOR

4.5.4 Supervisory Control of Requester Facilities

AEP will not operate equipment for which it is not responsible. Therefore, these general real-time operational data requirements exclude supervisory control points for Requester facilities. In some cases, AEP may enter into a specific agreement to operate a Requester's equipment, and AEP could require supervisory control points in order to perform contractually defined duties. In addition, certain status and analog points not covered in this document may be needed. Real-time operational data requirements for such agreements are out of scope for this document and will be addressed individually according to their respective agreements.

4.5.5 SCADA Requirements for AEP Facilities

Before AEP approves an interconnection request, facilities must be equipped with full Supervisory Control and Data Acquisition (SCADA) capability. Existing AEP-owned facilities that provide a connection to the Requester, or facilities the Requester will build and AEP will own under an option to build (OTB) arrangement must meet the following specifications:

- Have a combination of an RTU and intelligent electronic devices (IEDs) at an AEP-owned substation or switching structure. The SCADA equipment must be engineered and installed according to AEP's internal standards. AEP will operate and maintain the equipment exclusively.
- Provide full visibility and supervisory control of AEP's interconnection facility by using a full complement of real-time operational data needed for situational awareness. This data will include (but not be limited to) all voltage, current, power measurements, as well as status and alarm indications for all primary facility components.
- Supervisory control is required for all equipment, primarily circuit breakers and MOAB switches used to interconnect the Requester to AEP. Point selection for the AEP-owned facility must be made in conformance with *SS-502000 Substation SCADA*.
- Connections to AEP are not permitted at locations or facilities that do not provide adequate situational awareness and supervisory control to AEP Energy Delivery Operations personnel and RTEs.

4.5.6 Requester Real-Time Operational Data Requirements

Requesters may require real-time operational data from AEP facilities in order to maintain their facilities' safe and reliable operation. AEP supplies all required real-time operational data to the RTEs in which it is registered. AEP's strong recommendation is that Requesters obtain such data by using Inter-Control Center Communications Protocol (ICCP) interactions with those RTE entities. If ICCP use is not feasible, the Requester can request direct access to real-time operational data for AEP facilities related to its transmission system connection.

AEP will provide limited access to revenue meters and/or remote terminal units (RTUs) capable of providing that data per the *SS-500000 AEP SCADA RTU Requirements for Transmission Interconnection Facilities*. Fulfillment of such requests will be documented in the interconnection agreement and fall within the bounds of AEP transmission standards and common utility practice. Data connectivity for Requester data acquisition connections will be established in accordance with fiber optic or other communications facility requirements covered in Section 4.7 Telecommunications in this document.

4.6 Metering Requirements

This section specifies AEP's metering requirements for connecting to its transmission system. These requirements apply to all facilities requesting connection to AEP. References to metering package includes the revenue meter and metering instrument transformers (ITs). Otherwise, separate references will be made to the meter or ITs only.

4.6.1 Industry Standards Exceptions

To the extent that these requirements conflict with the standards and guidelines of any applicable RTE regarding transmission interconnection metering requirements, the standards and guidelines of such RTE take precedence.

4.6.2 Introduction

The metering package design must be sensitive to a wide range of applications for accurate metering of any bidirectional or radial Transmission Interconnection (TI) over the full range of possible scenarios. As an example, the metering package will accurately meter interconnections with injected generation (100's MW in one direction) and backfeed power (less than 1 MW) in the reverse direction. If the metering package cannot be specified to meet the manufacturer's guaranteed accuracy to capture the Requester backfeed load properly, additional metering will need to be evaluated for the Requester's auxiliary load centers.

In addition, if the Requester auxiliary load centers can have different owners, then separate metering is required. Also, telemetry requirements may vary slightly. Therefore, the design of the metering package devices must be flexible. Metering device redundancy is supported (primary and backup energy meters) because transmission revenue metering data is critical. If a project requirement is not covered in this document, or if there are any questions regarding revenue metering application design, consult with AEP's Protection & Control Engineering (PCE) Standards group for clarification. Also, refer to the following AEP transmission standards for more guidance: *SS-497001 Transmission Intercompany & IPP Metering Guide, SS-490050 ERCOT-EPS*[34] *Metering Design Guide, and SS-494001 Transmission Customer Metering Design Guide*.

4.6.3 Requesters and Metering Criteria

- **Affiliate EUC Requester**
  AEP will provide functional specifications for the revenue metering at the Requester's facility for the affiliate EUC. The criteria for these functional specifications will be based on existing AEP measurements practices and standards. AEP reserves the right to specify and approve the type and manufacturer of all associated revenue metering equipment, including the instrument transformers. If requested, subtle changes to the standard AEP metering package are acceptable with mutual agreement between AEP and the Requester. AEP will own the metering package and have testing responsibility.
- **Non-affiliate EUC Requester**
  This Requester can own the metering accuracy ITs. AEP will provide functional specifications for the revenue metering package. The criteria for these functional specifications must be based on existing AEP measurements practices and standards. AEP reserves the right to specify and approve the type and manufacturer of all associated revenue metering equipment including the instrument transformers. Specific agreements will describe exceptions and IT ownership details. AEP will own the meter and have meter testing responsibility.
- **TI Requester**
  This Requester can have metering package ownership when the transmission line ownership boundary occurs at the Requester's facility. It eliminates the need for compensation calculations

[34] For *Section 4.6 Metering Requirements*, EPS refers to ERCOT Polled Settlements.

related to line loss. If it is determined that the TI Requester will own/maintain the metering package, the Requester will provide AEP with accuracy documentation of the meter package components.

- **GC Requester**
  This Requester's meter location can vary, but the preference is to install the GC metering package at the AEP station, which AEP owns/maintains, and may result in the need for loss compensation calculation. Separate GC auxiliary load metering will be required if the specified metering on the generation connection does not provide adequate meter accuracy for its backfeed load, or if GC facility auxiliary loads can have different owners.

4.6.4 Metering Equipment Maintenance & Testing

- Unless otherwise specified, the energy meters must be inspected and tested in accordance with latest applicable ANSI Standards upon installation. The test cycle will vary, depending on region. Refer to *SS-491301 Field Service Testing* for AEP-owned meters. If the Requester needs additional testing other than the normal test cycle, and the meter is found to be within the established tolerances, this additional testing will be performed at the GC, TI or EUC Requester's expense.
- The accuracy of each device in the metering package must be maintained according to the RTE criteria where the meter is installed. The meter test requires the use of a meter standard with accuracy traceable to the National Institute of Standards and Technology (NIST).
- If the metering equipment fails to operate, the energy registration will be determined from the best data available, including backup metering, check metering, or historical metering data.
- The RTE error disclosure criteria must be followed if, at any test of the metering equipment, meets that error criteria. The account between the parties for service before delivered must be adjusted to correct for the inaccuracy. The adjustments will be made according to the applicable regional market guidelines.
- ITs must be inspected and maintained in accordance with good utility practice. AEP-owned ITs must be inspected and maintained based on existing AEP station practices and standards.
- The party that owns the metering equipment must maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with good utility practice for the life of the interconnection point. The other party must have reasonable access to the records.

4.6.5 Instrument Transformers

4.6.5.1 230kV and Below

- Separate, free-standing, oil-filled, wire-wound current transformer (CT) units with high accuracy (0.15SB1.8) and extended range are the standard instrument transformer.
- Separate, free-standing, oil-filled, wire-wound voltage transformer (VT) units with high accuracy (0.15%) are the standard instrument transformers.
- High accuracy (0.15%) Combination CT/VT units (combo) can be applied where space constraints or ease of application require their use.

- An exception is made for voltages 34.5kV and below where solid insulated instrument transformers with high accuracy (0.15%) can be applied.

4.6.5.2 IPP Applications 345kV and Above

PJM

- Separate, free-standing, oil-filled, wire-wound CT units with high accuracy (0.15SB1.8) and extended range have been selected as the standard instrument transformer.

  Reason: Independent Power Producers (IPPs) have a high power output, but when not generating, IPPs have a very low load and extended range CTs have supported higher accuracy down to 0.05% of rating (or better). High accuracy bushing current transformers (BCTs) are only guaranteed down to 5% of rating.

- High accuracy (0.15%) Capacitive Voltage Transformer (CVTs) can be used.

ERCOT EPS & SPP

- Separate, free-standing, oil-filled, wire-wound CT units with high accuracy (0.15SB1.8) and extended range have been selected as the standard instrument transformers.
- Separate, free-standing, oil-filled, wire-wound VT units with high accuracy (0.15%) have been selected as the standard instrument transformers (see reason below).

  Reason: CVTs are not recommended on ERCOT EPS applications or SPP region due to a requirement to accuracy test the CVTs every five years. In order to avoid unnecessary outages, AEP will not use CVTs for this application. Meter points in ERCOT that are non-EPS can use high accuracy (0.15%) CVTs.

4.6.5.3 Non-IPP Applications 345kV and Above

PJM

- High accuracy (0.15S-B1.8) BCTs
- High-accuracy (0.15%) CVTs

SPP

- High accuracy (0.15S-B1.8) BCTs
- Separate, free-standing, oil-filled, wire-wound VT units with high accuracy (0.15%) are the standard instrument transformers. See reason in ERCOT EPS below.

ERCOT EPS

- Separate, free-standing, oil-filled, wire-wound high accuracy (0.15S-B1.8) CT units are the standard instrument transformers.
- Separate, free-standing, oil-filled, wire-wound VT units with high accuracy (0.15%) are the standard instrument transformers.

  Reason: CVTs are not recommended on ERCOT EPS applications or SPP region due to a requirement to accuracy test the CVTs every five years. In order to avoid unnecessary outages, AEP will not use CVTs for this application. Meter points in ERCOT that are non-EPS can use 0.15% high accuracy CVTs.

4.6.6 Voltage Transformer Ratio

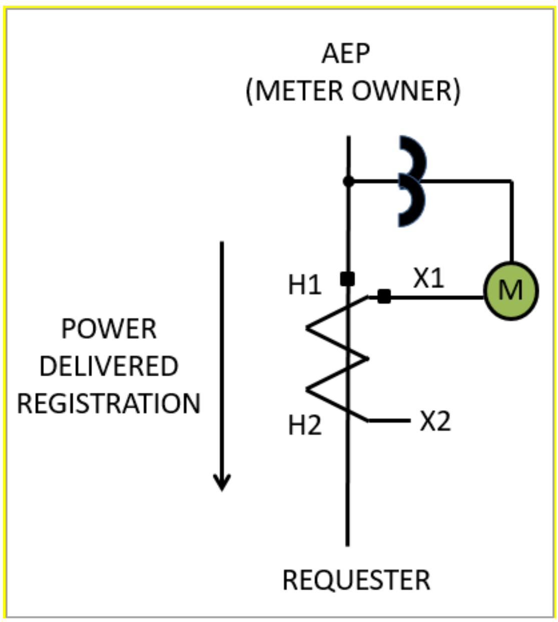
The voltage transformer ratio must be specified with a ratio to provide a nominal of 120 volts at the meter.

4.6.7 Polarity

If AEP owns the meter and is responsible for settlement, then the polarity marking (designated as H1) on the primary side of the instrument transformer must be oriented toward AEP. See *Figure 9* below. The CT secondary terminal designated as X1 is to be connected to the positive current terminals of the energy meter (assuming VTs are connected properly), current flow in H1 (from AEP) and out H2 (to Requester), will register positive MWh (delivered) by the energy meter.

Conversely, for reverse power flow from the interconnecting Requester to AEP (in H2), negative MWh (received) will be registered on an independent register of the energy meter if AEP owns the meter and is responsible for settlement. Note the orientation of the VT primary connection, which is shown between the meter owner, AEP, and the CT. The VT orientation is AEP's practice where it can be done physically so that the meter does not register VT losses.

Figure 9. CT Polarity and VT Connection



4.6.8 Meter Requirements

4.6.8.1 Revenue Meter

The revenue meter accuracy must follow the applicable RTE criteria for where it is installed and must be cabable of MV90 remote readings.

4.6.8.2 Requester Access to AEP Metering Circuits

- The revenue meter must be the only device connected to the metering accuracy instrument transformers.

  Note: There are exceptions where unused secondary windings of the voltage source for applications at 345kV and above can be used in AEP protection relay devices. However, there must be no RTE restrictions for such a case.

- Requesters may specify a check meter in the revenue metering circuit on the same panel or adjacent panel to the revenue meter. The Requester will be responsible for additional costs needed for AEP to provide data connection/communication access to the revenue meter. AEP Transmission PCE Standards must approve this arrangement.

4.6.9 Data Acquisition

4.6.9.1 AEP Access to Real-time Meter Data

If an AEP RTU is present, it will poll the meters. If an AEP RTU is not present, the AEP SCADA system can poll the meters directly when AEP Settlements needs real-time data.

The SCADA RTU design dictates which options (Ethernet or RS-485 serial) are chosen for the meters. An AEP-owned local area network (LAN) connection is preferred for AEP-owned meters. Refer to *SS-500000 Interconnected Facilities SCADA Guide,* and *SS-490100*, *Station Revenue Energy Meter Communication Options* for directions on the data communications interface.

4.6.9.2 Requester Access to Real-time Meter Data

If the Requester needs real-time data from the meter, the connection provided will depend on the SCADA system design. If an AEP RTU polls the meters, AEP may grant the Requester serial access to the AEP RTU. If an AEP RTU is not present, AEP may grant the Requester serial access to the meter(s). Refer to *SS-500000 Interconnected Facilities SCADA Guide*, and to *SS-490100, Station Revenue Energy Meter Communication Options* for directions on the data communications interface.

4.6.10 MV90 Interval Data Retrieval

The AEP Transmission Settlements or Load Research group will use the AEP MV90 data translation system to interrogate AEP-owned revenue energy meters (primary and backup). If the Ethernet is connected to the SCADA wide area network (WAN), MV90 can interrogate the meter's Ethernet port. If the meter's Ethernet port is not connected to the transmission system network, it will be polled using a cellular Internet Protocol-based connection.

If the Requester needs meter interval data retrieval, then a meter serial port can be used, or AEP can be provide an internet proxy.

4.7 Telecommunications Facilities Requirements

4.7.1 Fiber-optic Cable Requirements

The Requester's Interconnection Agreement with AEP will identify requirements for fiber-optic cable installation between Requester and AEP facilities. The agreement could include a requirement for the Requester to install redundant and diversely routed fiber-optic cables. AEP Protection & Control (P&C) Engineering prefers direct fiber relaying rather than fiber optic multiplexers. In addition to using the fiber-optic cable for relaying, supplemental AEP network and serial data connections can be used in the system interconnection design.

The Requester must not terminate or route fiber-optic cable with metallic members at or through the Requester's substation (Substation) control building or the telephone company demarc. Fiber-optic cable with metallic members includes, but is not limited to, optical ground wire (OPGW), fiber-optic cable with an integral trace wire, and metallic-armored fiber optic cable.

Fiber-optic cable with metallic members must be transitioned to all-dielectric fiber-optic cable. AEP must approve fiber-optic cable before it enters the Requester's control shelter or the telephone company interface.

4.7.2 Demarc Requirements

AEP and the local exchange carrier (LEC) must approve all demarcation equipment (demarc or telephone company interface box) for all telephone company circuits that are leased to a Requester-owned Substation. The Requester will install, own, and maintain this equipment.

The demarc must house all telephone company circuit termination equipment at the Substation, including, but not limited to, the network interface and high-voltage (HVP) equipment (See 4.7.3 below). The demarc must provide the interface between the telephone company's service cable and the Substation. The Requester must provide 120 VAC power to the demarc sourced from an appropriately sized DC/AC inverter in the Substation control building. The DC/AC inverter must be powered from a dedicated Substation DC breaker sourced from a minimum 8-hour Substation battery.

If the demarc is located in a position that makes it impractical to power from the station battery, the Requester must have another way to provide 120VAC service to the demarc. AEP must approve this arrangement. The demarc design will include provisions to extend the leased circuit into the Substation control house or other enclosure where AEP equipment will be placed. The demarc must be located on the Substation ground grid, unless HVP requirements cause it to be placed elsewhere. The demarc must be accessible outside the Substation fence or through a secured personnel gate or door.

Telephone company personnel will not have access to the control building housing an AEP RTU. Demarc design must include 24/7 access for AEP personnel without escort from the Requester, telephone company personnel, facility operator, or landowners. Before demarc construction begins, the Requester must submit its design to AEP for review and approval. The design must include physical locations of the telephone company's service cable, Substation ground grid, demarc mounting structure, Substation fence, and Substation control building. Demarc design covered in this section must be operational, and AEP must commission the design before the interconnection facility is placed in service.

4.7.3 High Voltage Isolation Requirements

The demarc must meet all high-voltage protection (HVP) requirements according to the LEC as follows:

- LEC Service – All-dielectric fiber-optic service cable
  - AEP must approve cable design and implementation.
  - The Requester will work with the telephone company to install, own, and maintain all-dielectric fiber service cable to the demarc location of the Requester-owned substation (Substation) ground grid.
  - Armored fiber-optic cable must not be installed within the ground potential rise (GPR) high voltage zone of influence.
  - The telephone company must transition armored fiber-optic cable to all-dielectric fiber-optic cable outside the GPR high voltage zone of influence. This all-dielectric, fiber-optic service

cable must extend from a location at or beyond the 300 volt point, through the GPR high voltage zone of influence, to the demarc.

  - Telephone company personnel must have 24/7 access to the all-dielectric fiber-optic service design without escort from AEP personnel, Requester personnel, facility operator or landowners.

- LEC Service – HVP equipment with copper service cable
  - AEP and the telephone company must approve the equipment.
  - The Requester or local telephone provider must install and maintain equipment.
  - AEP will have no responsibility for maintaining any part of the telephone company demarc or equipment.
  - Copper isolation equipment must be located on the Substation ground grid, unless the LEC has different requirements.
  - Equipment design must include adequate protection against GPR.
  - Equipment installation is required on all telephone company circuits delivered over copper cable to the Substation demarc in compliance with LEC requirements.
  - Access to equipment is required outside the Substation fence or through a secured personnel gate or door.

4.7.4 Circuit Requirements

In some cases, AEP may assign the Requester responsibility for communication circuits that AEP will use. The Requester will be responsible for confirming project-specific circuit requirements and obtaining specific AEP addresses and AEP contact names in preparation for issuing communication circuit orders with AEP. Circuit(s) will be multi-protocol label switching (MPLS) with AT&T, Verizon, or an alternative satisfactory to AEP. The AEP account team will order the circuits from their telecommunication service provider of choice.

The Requester must provide AEP and the telecommunication service provider advance authorization for communication circuit maintenance. AEP and any of its affiliates or subsidiaries can monitor the circuit, report trouble, and take corrective action with the telecommunication service provider, at the Requester's expense, to maintain circuit reliability. This requirement applies to all leased Requester circuits.

The Requester must install and maintain voice communications that meet requirements identified by AEP, OpCo, transmission company, RTE, or applicable agreements. Backup communication circuits may be required according to the agreement. Communication circuits must be operational and AEP must commission the circuits before the interconnection facility is placed in service.

Typical facility circuit requirements include:

- AEP Network Communications Circuit – A leased circuit from the demarc associated with the Requester-owned Substation to an AEP dispatch office.
- Voice Dispatch Circuit – A leased circuit from the Requester facility plant operators to an AEP dispatch office. If the Requester facility plant operators are not located on the plant site, then the circuit must be terminated at the plant operators' actual location. The Requester must provide a dedicated circuit where the total plant generation capacity is equal to or greater than 50 MVA.

This circuit must use dedicated, private line automatic ring down (PLAR) technology and must not rely on the public switched telephone network. AEP must approve this service configuration.

4.8 Station Service

4.8.1 Substation Lighting

Service Lighting is not required on new AEP station installations. Stations containing AEP owned equipment shall comply with AEP lighting standard SS-410000 latest revision. Security Lighting (0.5FC minimum) must be provided at all AEP equipment locations. With security lighting, personnel must be able to observe equipment locations from outside the station fence, and such lighting will serve as a deterrent to keep people from trespassing and/or tampering with equipment.

4.8.2 AC Station Service System

AC station service power systems in AEP and Requester stations must be independent and derived separately. AEP must approve the AC station service system's construction that serves AEP equipment when AEP facilities are located in the Requester's substation. The standard station service voltage is center-tapped 120/240VAC for single-phase or three-phase system. A three-phase system must use open-delta or closed-delta secondary only. For service power serving AEP facilities AC station service systems must comply with the *AEP Standard SS-010000 Service Power for Electrical Stations Design Guide* and *SS-010090 AC/DC Panelboard and AC Station Service Switchboard Specification for Substations*

4.8.3 DC Station Service System

The standard AEP battery voltages for new installations is 125 VDC. Each substation must have a properly sized battery and charger to carry the DC station loads during an AC power failure. Where the DC station service system is supplying AEP owned equipment the DC station service system will not be smaller than the requirements described in *AEP Standard SS-181000 DC Station Service Application Guide*. Requirements outlined in *SS181000* are based on IEEE-485 calculations.

For equipment combined within a single fenced station, AEP Transmission and AEP-affiliate owned DC station service power systems shall only serve AEP Transmission and AEP-affiliate owned and maintained equipment. DC station service power systems serving equipment not owned and maintained by AEP Transmission or AEP-affiliates shall be independent and separately derived. AEP and Requester-owned equipment located in separate fenced stations must have independent and separately derived station service power systems.

4.9 Transmission Line Design

Transmission line design and construction begins after the point of connection is determined. When this work is required for new transmission line facilities on the AEP system to connect the requester's facilities, it must be completed in compliance with:

- *ANSI-C2*, National Electrical Safety Code (NESC), latest edition
- Governmental agencies as needed to obtain permits to construct the line (e.g., the U.S. Army Corps of Engineers or the Federal Aviation Administration)
- Additional applicable state and local code or criteria

- The requirements in *Table 13* below

In addition, all transmission line facilities on the AEP system that involve carrying AEP services to more than one customer, or that AEP will own or maintain, must comply with the design requirements in Table 13 below.

Table 13. Requirements for All Lines Connected to the AEP Transmission System

<table>
<tr><th rowspan="2">Parameters</th><th colspan="7">Requirements</th></tr>
<tr><th>≤69kV</th><th>138kV</th><th>161kV</th><th>230kV</th><th>345kV</th><th>500kV</th><th>765kV</th></tr>
<tr><td>Extreme Wind Loading</td><td colspan="7">Use ASCE MOP 74-2020 for the 100 year Mean Return Interval (MRI) load as appropriate for the line's location</td></tr>
<tr><td>Heavy Ice Load (No Wind)</td><td colspan="7">Use ASCE MOP 74-2020 for the 100 year Mean Return Interval (MRI) load as appropriate for the line's location</td></tr>
<tr><td>Ice with Concurrent Wind</td><td colspan="7">Use ASCE MOP 74-2020 for the 100 year Mean Return Interval (MRI) load as appropriate for the line's location</td></tr>
<tr><td>Unbalanced Loads [1,2]</td><td colspan="7">Tangent and Running Angle Structures will be designed for the following loads:
Broken Phase (single conductor) - 12.25 psf wind with 0" ice at 0°F
Broken Phase (two or more bundled conductors) - 0 psf wind with 0" ice at 60°F
Broken Ground Wire - 12.25 psf wind with 0' ice at 0°F
Unbalanced Ice (Iced span) - 6.25 psf wind with 0.5" ice at 0°F
Unbalanced Ice (Bare span) - 6.25 psf wind with 0" ice at 0°F</td></tr>
<tr><td>NESC Load Requirements</td><td colspan="7">All NESC Load requirements, 250B, 250C, and 250C for Grade B construction will be met.</td></tr>
<tr><td>OPGW (Optical Ground Wire) Standards</td><td colspan="7">OPGW will comply with AEP Standard OPGW Requirements in Table 16 or equivalent.</td></tr>
<tr><td>Static Ground Wire Standards</td><td colspan="7">Static wire needs will be determined by available fault current on the line. All static wire shall be aluminum-clad steel or ACSR conductor. 7-#8 is the minimum size that shall be used.</td></tr>
<tr><td>Damper Requirements</td><td colspan="7">Aeolian vibration dampers are required unless an engineering study indicates otherwise or twisted-pair conductor is being used.</td></tr>
<tr><td>Galloping Assumptions</td><td colspan="7">Galloping will be considered for all lines in Indiana, Michigan, western Ohio, Oklahoma, and West Texas north of Abilene. In areas not mentioned above, galloping need not be considered unless local knowledge indicates otherwise.</td></tr>
<tr><td>Galloping</td><td colspan="7">For all spans, apply the Cigre Ellipse[4] with a 0.5 amplitude factor. The ellipses must have the separation shown in the table below plus the bundle spacing if the line uses bundled conductor. The use of twisted-pair conductor or other mitigation devices is allowed to mitigate galloping.

<table>
<tr><th>Voltage</th><th>69kV</th><th>138kV</th><th>161kV</th><th>230kV</th><th>345kV</th><th>500kV</th><th>765kV</th></tr>
<tr><td>Phase-Phase (ft)</td><td>1.5</td><td>2.0</td><td>2.5</td><td>3.0</td><td>4.0</td><td>6.5</td><td>8.5</td></tr>
<tr><td>Phase-Ground (ft)</td><td>1.0</td><td>1.5</td><td>2.0</td><td>2.5</td><td>3.0</td><td>4.5</td><td>6.5</td></tr>
</table></td></tr>
</table>

Parameters	Requirements						
	≤69kV	138kV	161kV	230kV	345kV	500kV	765kV
Spacers	The use of spacers in 2-conductor horizontal bundles or bundles of more than 2 conductors is required. Spacer-dampers are allowed.						
Min. Design Clearance	All as built facilities will comply with NESC Clearance Requirements.						
Min. Insulation Leakage Distance [3]	49" 68" 84"	98" 136" 168"	110" 159" 197"	163" 227" 281"	245" 340" 421"	355"	543"
Min. Critical Impulse Flashover Voltage	495kV	760kV	930kV	1105kV	1585kV	2065kV	-2685kV middle phase -2530kV outside phase
Max. Structure Ground Resistance	20 Ω	20 Ω	20 Ω	20 Ω	20 Ω	20 Ω	20 Ω
Max. Shielding Angle	30°	30°	30°	15°	15°	15°	5°
EMF Limits	Must comply with all applicable local, state, and federal regulations.						
Footnotes:							
[1] For all longitudinal load cases, the design load shall be calculated by determining the greatest mechanical load resulting from breaking, removing, or unbalanced ice in the fore span, back span, or tap span. For 138kV lines and below, dead-end structures may be installed at least every 5 miles in lieu of designing for the broken phase, broken ground wire, and unbalance ice loads.							
[2] For vertically bundled conductors without spacers, use the single conductor load case for one sub-conductor for the broken phase loading.							
[3] The three values shown are for Normal, Heavy, and Very Heavy Contamination according to the latest International Electrotechnical Commission (IEC) recommendations. For 500kV and 765kV lines in heavy or very heavy contamination areas, consult AEP Transmission Line Standards.							
[4] For information on the Cigre Ellipse calculation, see *Cigre Technical Brochure Reference 322; State of the Art of Conductor Galloping.*							

Table 14. Additional Requirements for Lines Connecting to the AEP Transmission System

Parameters	Requirements						
	≤69kV	138kV	161kV	230kV	345kV	500kV	765kV
Conductor Sizes for New Construction	For AEP-owned or maintained line, the conductor will be chosen from the *AEP Standard Conductor Table 15*. The conductor for non-AEP owned or maintained lines shall be in the Interconnect Agreement.						

Min. Right-of-Way (ROW) Width	Minimum ROW widths on AEP-owned or maintained lines must be calculated based on NESC clearance requirements to buildings with the conductor displaced by a 6 psf wind at 60°F and at rest.
Provisions for Live Line Maintenance	For AEP-owned or maintained lines, the Minimum Approach Distance according to Occupational Safety and Health Administration (OSHA) regulations for live line work and climbing inspections will be provided.

Table 15. AEP Standard Conductor Table

Size (CM) & Code Name	Stranding	Type	Type
69kV Lines			
1-477,000 - Hawk	26/7	ACSR	ACSS
1-556,500 - Dove [1]	26/7	ACSR	ACSS
1-795,000 - Drake [2]	26/7	ACSR	ACSS
1-954,000 - Cardinal	54/7	ACSR	ACSS
1-1,033,500 - Curlew	54/7	ACSR	ACSS
138kV and 161kV			
1-556,500 - Dove	26/7	ACSR	ACSS
1-795,000 - Drake [1]	26/7	ACSR	ACSS
1-1,033,500 - Curlew [2]	54/7	ACSR	ACSS
1-1,272,000 - Pheasant	54/19	ACSR	ACSS
1-1,590,000 - Falcon	54/19	ACSR	ACSS
230kV [3]			
1-1,033,500 - Curlew	54/7	ACSR	ACSS
1-1,272,000 - Pheasant	54/19	ACSR	ACSS
1-1,590,000 - Falcon	54/19	ACSR	ACSS
2-795,000 - Drake	26/7	ACSR	ACSS
345kV [3]			
2-954,000 - Cardinal	54/7	ACSR	ACSS
2-1,272,000 - Pheasant	54/19	ACSR	ACSS
2-1,590,000 - Falcon	54/19	ACSR	ACSS
Footnotes			
[1] Preferred conductor for rural construction			
[2] Preferred conductor for urban construction			
[3] There is no preferred conductor for 230kV and 345kV.			

Table 16. OPGW Design and Fiber Requirements

	Minimum	Maximum
OPGW "Mechanical" Design Parameters [1]		
Overall Diameter [2]	0.646 inch (16.4 mm)[2]	
Rated Breaking Strength [3, 4]	17,000 lbs. (75.6 kN) or 25,500 lbs. (113.4 kN)[3]	
Diameter or Smallest Dimension of Metal Strands:		
Outside Layer[5]:		
Aluminum-Clad Steel Wires (per ASTM B415)	0.1285 inch (3.25 mm)	
Inner Layers:		
Aluminum-Clad Steel Wires (per ASTM B415)	0.100 inch (2.5 mm)	
Aluminum 6201-T81 Alloy Wires (per ASTM B398)	0.100 inch (2.5 mm)	
Aluminum Wire 1350-H19 (per ASTM B230)	0.100 inch (2.5 mm)	
Fault Current Capability, I squared × T[6]	140 [kiloamps] squared × seconds or as specified in RFQ	
Continuous (RMS) Current	Zero (0) or as specified in RFQ	
Single Mode Fiber Requirements [7]		
Optical Attenuation [8]		
@ Wave length = 1310 nanometers (nm)		0.36 dB/km
@ Wave length = 1550 nanometers (nm)		0.25 dB/km
Total Chromatic Dispersion [8]		
@ 1285 - 1330 nm, (ps/nm - km)		3.5
@ 1530 - 1570 nm, (ps/nm - km)		17.0
Core to Cladding Concentricity Error		1.0 µm
Core Diameter		9.0 µm
Cut-Off Wavelength @ 1310 nm	1130 nm	1270 nm
Typical unspliced OPGW Reel Length	4 miles (21,100 ft.; 6.4 km)	
Footnotes		
[1]As used herein, OPGW is an abbreviation for "Composite, Single-Mode, Optical Fiber Ground Wires for Overhead Use."		

	Minimum	Maximum
[2]The OPGW overall diameter shown is the preferred value so that the associated hardware may be interchangeable. If the specific OPGW being designed, with varying numbers of optical fibers and fault current requirements, requires overall diameters larger than shown, the vendor may quote the larger diameter. In general, within the context of the other OPGW requirements, it is preferred to try to minimize overall diameters.		
[3]The OPGW shall be designed such that, for tensile loads up to 95% of its rated breaking strength (RBS), the optical fibers shall not be damaged and their optical transmission characteristics shall not be affected. If the OPGW is designed such that at a tension equal to 95% of the RBS the optical fibers are subjected to strain, the tension in the OPGW from a 1.25" Radial Ice Load at 0ºF with No Wind shall not exceed 60% RBS (i.e., 60% of 25,500 lbs.). If the OPGW is designed such that at a tension equal to 95% of the RBS the optical fibers are subjected to no strain, the tension in the OPGW from a 1.25" Radial Ice Load at 0ºF with No Wind shall not exceed 90% RBS (i.e.; 90% of 17,000 lbs.).		
[4]The Rated Breaking Strength (RBS) of the OPGW shall not exceed the rated strength of the component strands times a strength reduction factor of 0.90. The minimum RBS requirements are for the preferred OPGW diameter. Actual minimum RBS requirements may need to be higher depending on the specific overall diameters and bare weights of each type of OPGW having varying numbers of optical fibers included.		
[5]The outer layer of strands on the OPGW is to consist only of aluminum-clad steel wires with the minimum diameter specified and is to be Left-hand Lay.		
[6]The required Fault Current Capability, I squared × T, is based upon an OPGW ambient reference temperature of 40ºC (104°F) and a fault duration of 0.25 seconds.		
[7]Single Mode Fibers are to be Corning Specification SMF-28 (latest revision) or the comparable Lucent specification. The use of fibers from other suppliers must be approved in advance by AEP. All optical fibers supplied as part of any one Purchase Order for OPGW shall be supplied from a single source.		
[8]Maximum attenuation and total chromatic dispersion values apply to each fiber within the OPGW for each reel.		

5.0 Construction

The following subsections outline the requirements associated with the construction phase of a typical project, including option to build oversight and inspections.

5.1 Option to Build Oversight Requirements

AEP has guidelines specific to the option to build (OTB) process. They identify AEP's recommendations, expectations, and requirements for Requesters electing to use the OTB transmission facilities as part of their generation facilities interconnection. The *Independent Power Producers Option to Build Guidelines* are located on AEP.com[35] in the AEP Transmission Studies and Requirements section on the Required Postings page. Interconnection Agreements or applicable tariffs supersede these guidelines.

5.2 Inspection Requirements

5.2.1 General Inspections

An interconnection facility must pass AEP inspections before it can be energized to maintain the integrity of the grid. The quantity and frequency of inspections will depend on the type of connection, proximity of connection to existing AEP facilities, any safety concerns due to existing or new facilities or accessibility by the public, and the Requester's project.

5.2.1.1 Protection & Control Inspection

For cut-in outages, an AEP Energy Delivery Representative will retain a construction clearance on the site until the Requester fulfills all of its construction requirements. An AEP Protection & Control (P&C) staff member can retain clearances until all desired/necessary checkouts are completed. AEP reserves the right to inspect all equipment from the point of interconnection to the first protective fault interrupting device and the ground system. This inspection may include circuit breakers, circuit switchers, power fuses, instrument transformers, switches, surge arresters, bushings, and relays and associated equipment including battery, battery chargers or other customer equipment. The inspection may include a visual check of all major equipment and an examination of required test results.

5.2.1.2 Pre-Energization Inspection

At least five business days before energization, an Energy Delivery Representative will attest to all series equipment as required by AEP compliance documentation. The Requester and AEP SCADA personnel must commission and validate the facility before it is declared ready for operation. Validation points are defined in *Sections 4.5.3, 4.5.4, 4.5.6*, and other applicable agreement(s) between AEP and Requesters.

[35] https://www.aep.com/requiredpostings/AEPTransmissionStudies

6.0 Operations

The following subsections outline the requirements associated with facility operations, including general requirements, in-service coordination, NERC requirements, meter agent and settlements requirements, and many more.

6.1 General Operating Requirements

This section outlines the operational requirements for the Requester's connected facilities. Energy Delivery Operations must manage and operate transmission and interconnection facilities based on NERC, regional, and applicable RTE reliability standards. The Requester is responsible for meeting AEP operational requirements in a timely manner, whether or not their connected facilities are in operation. This requirement applies to any transmission operating condition.

A connected facility **must not**:

- Impact safe electric grid operation.
- Increase the risk of in system reliability constraints that stem from facility failures.
- Increase frequency and duration of outage interruptions.
- Prevent effective resource usage to provide efficient and cost-effective service to customers.
- Impact service reliability and capacity to customers.
- Decrease system flexibility associated with day-to-day operations.

The Requester is solely responsible for proper coordination of its equipment with the transmission system and must provide the most current specifications for interconnection equipment, including drawings and one-line diagrams to AEP for review. AEP's review does not confirm or endorse the design, or as a warranty of safety, durability, or reliability of the facility. The Requester must submit any future changes to the specifications that could affect AEP Energy Delivery Operations to AEP for review and approval.

All interconnecting facilities must be operationally tested and/or inspected in order to meet current requirements as specified in *Section 5.2*.

Before the facility is declared ready for operation, the Requester must provide AEP with the name, title, address, telephone number, and email address of individual(s) who will operate the facility. The Requester must keep AEP informed regarding contacts and maintain proper communication channels between AEP and the Requester.

6.2 Advanced In-Service Coordination

The Requester must provide the AEP project manager an advanced written notice of their GC, TI or EUC facility in-service date. The greater of 45 days or any RTE in-service date notification requirements will be used as the advanced written notice time constraint. AEP Energy Delivery Operations will use this time period to ensure that telemetry, system models(s), communication and procedures of all stakeholders are verified.

6.3 Transmission Service and NERC Registration

All entities required to register, under *NERC's Rules of Procedure, Appendix 5A, Section 1*, must provide AEP with this NERC registration information at least 30 days before the in-service date. AEP assumes no additional compliance obligations beyond its NERC registrations, unless specifically defined in a signed interconnect agreement.

6.4 Meter Agent and Transmission Settlements Requirements

Transmission Settlements is responsible for maintaining the system of record for all AEP transmission system loads. Transmission loads represent the amount of load on the AEP transmission system. Load is modeled by metering all generation flowing onto the system, plus interconnection receipts from other transmission systems less deliveries to other transmission systems. AEP loads are calculated by taking the transmission system load and removing non-AEP load (also called top-down load calculation).

Transmission Settlements acts as the meter agent for all AEP entities and some non-AEP entities for AEP zones in the PJM and SPP markets. The main responsibility is to provide meter data to the market for financial billing. Because the calculation of the AEP top-down loads includes all points on the system, Transmission Settlements prefers to be the meter agent in order to minimize errors or mismatched data in the markets.

Transmission Settlements requires the following:

- To be included in and updated on projects during the planning and set-up phase in order to provide feedback and prepare for system changes.
- Revenue quality metering and backup metering (when applicable) installed and compensated to the point of interconnection of AEP's transmission system.
- Access to read meters or other methods to receive meter data.
- To be provided with the following information:
  - Clear location of the point of interconnection.
  - Any losses or losses factors that should be applied in the meter or translation.
  - Designation of meter ownership.
  - Maintenance agreements for all metering equipment including metering transformers.
  - Contact information for meter data reconciliation.
- Any connected Generation must have:
  - Metering to capture generation and auxiliaries accurately.
  - Agreements in place to provide retail auxiliary service.
  - Clear guidance on the treatment of non-generated auxiliary load (NGA) and generation for market submission and retail contracts.
- A clause in all new or updated agreements for Transmission Settlements to be the meter agent in the PJM and SPP markets for all generation and load data on the AEP system; and to be the meter agent when AEP owns the metering on all transmission system to transmission system interconnections in those markets.

6.5 Station Load and Ancillary Service Provider

The Requester is responsible for making all appropriate arrangements for station load and ancillary service requirements, including the delivery component of transmission service, if applicable. The Requester must cause such station load and ancillary service provider arrangements or agreements to be in effect before the in-service date. If the Requester supplies their station service, the station service loads must be netted against the Requester's output. At AEP's request, the Requester must provide their current station service arrangements or agreements.

6.6 Synchronizing Facilities

The Requester is solely responsible for synchronizing its facilities with AEP in the appropriate frequency and voltage ranges, and protecting its facilities from all abnormal conditions occurring on the transmission system during synchronization. The Requester must install a relay with synchronizing function to ensure that their facility is not connected to the energized power system that is out of synchronization. The Requester must own, test, and maintain equipment that synchronizes their facilities to the transmission system to meet AEP's requirements.

Upon AEP supply loss, the Requester's facilities must be separated immediately from AEP. The Requester must ensure that their generator is disconnected from AEP before automatic reclosing by AEP. Otherwise, automatic reclosing out-of-phase with the Requester's generator may cause damage to the Requester's equipment. The Requester is solely responsible for their equipment protection during automatic reclosing by AEP. The Requester may also be responsible for installing additional equipment to operate in island mode and resynchronizing their islanding system to AEP.

At AEP's discretion, the Requester may be required to synchronize their facilities to the transmission system under the direction of AEP Energy Delivery Operations.

If the Requester's facility is a part of black start requirement, there may be additional provisions.

Any future changes to the design, logic, and settings that affect the Requester's synchronization and separation functions must be submitted to AEP for review and approval.

6.7 Asynchronous Network Interconnections

Asynchronous Network Interconnections, including high-voltage direct current (HVDC) connections, are treated on a case-by-case basis and the requirements for the Requester will be outlined as part of the RTE study process. If you need more detailed information on the requirements and process for these connection types, please contact the email outlined in *Section 2.1 Procedures*. The power quality requirements are covered in *Section 6.12 Power Quality Impacts*.

6.8 Voltage, Reactive Power, and Power Factor Correction

The Requester's generating equipment must not cause excessive voltage excursions. AEP will work with the Requester and the RTE to establish the normal operating voltage schedule, power factor schedule and operating limits. During emergency system conditions, the Requester's generation facilities must comply with all special instructions provided by AEP Energy Delivery Operations. Reference *Section 6.12* and *Section 3.3. General Design Information* for further details regarding voltage requirements.

Coordination of Scheduled Outages

The Requester must provide a schedule of all planned equipment outages to AEP and the RTE, and follow the applicable outage coordination procedures. At least 30 days advance notice is required. This period may be extended depending on the RTE

Voltage Control

The Requester's generating equipment must not cause excessive voltage excursions. The Requester must operate generating equipment in such a manner that there are no harmful impacts to system voltage levels. The Requester must provide an automatic method of disconnecting its generating equipment from the AEP facilities to protect against excessive voltage excursions. AEP will provide a reactive schedule letter that specifies generator voltage or power factor schedules and operation bandwidth. The Requester will install, operate, and service an automatic voltage regulator to maintain the assigned voltage schedule to the extent possible. The reactive schedule letter will include notification requirements for steady-state deviation from the voltage or power factor schedule and changes in automatic voltage regulator status as well.

The generation facility must be capable of continuous non-interrupted operation during normal system conditions and during abnormal conditions. All reasonable measures should be taken to avoid tripping the generation facility due to high or low voltage.

During plant start-up conditions, the Requester's auxiliary equipment must not cause excessive voltage flicker on AEP's electric facilities.

All three-phase generation must produce balanced 60 Hertz voltages.

Power Factor Control

The Requester must not place any undue burden on the AEP transmission system with respect to reactive power and must operate their equipment in accordance with any applicable power factor requirements specified in the Requester's agreements with AEP.

6.9 Dynamic MVAR Requirements

For generators, the dynamic MVAR capability at the current MW generation amount must be available in real time. If this dynamic MVAR capability is not available in real time, a dynamic capability curve plotted as a function of MW output is required.

The shunt static reactive available, but not in service, must be provided in sufficient detail to determine the amount of dynamic and static reactive reserve available. Applicability of this requirement based on generator size or size of combined generation, including DER aggregation, may be established in the near future.

6.10 Frequency Requirements

The AEP transmission system frequency operates at a nominal 60.0 Hz with a typical daily variation of ±0.05 Hz. The operating frequency of the Requester's equipment must not deviate from this AEP system frequency. Under emergency conditions, the transmission system could operate outside of this range for a limited period of time.

Generator underfrequency protection must be set to coordinate with the NERC-mandated automatic load shedding protection settings. The AEP underfrequency load shedding (UFLS) schemes begin dropping load between 59.50 HZ and 58.50 Hz in steps, based on the local Planning Coordinator/RTE requirements. Thus, the generator underfrequency protection must not operate before the system UFLS has a chance to respond. The Requester is responsible for setting their generator underfrequency protection to comply with the local Area Planning Coordinator/RTE requirements for generator underfrequency protection.

6.11 Abnormal Frequency Operation

The Requester will provide the frequency-sensing equipment required to protect their facility during abnormal frequency operation. The generator's manufacturing specifications or the range specified in *Section 6.10 Frequency Requirements* must be followed during abnormal frequency episodes.

The Requester's generator will not separate from the AEP system during under frequency conditions until all UFLS equipment on the AEP system has operated.

The Planning Coordinator may require an automatic load-shedding scheme on connected load to comply with North American Electric Reliability Corporation (NERC) standards or other system stability considerations. AEP is obligated to have an automatic UFLS plan in effect that meets these NERC standards. Connecting parties without an automatic UFLS plan for meeting these NERC requirements may need to install underfrequency relaying and have a load-shedding program in place, as the Planning Coordinator/RTE requires. The AEP Energy Delivery Operations Engineering team will specify the amount of load to be shed and frequency set points as set forth in the UFLS compliance requirements of NERC and the applicable Planning Coordinator/RTE.

6.12 Power Quality Impacts

AEP Power Quality Requirements

This section summarizes the AEP policy on power quality requirements including voltage flicker, harmonic distortion, and other factors for Requesters connected to the AEP transmission system.

Point of Compliance

The point of compliance (POC) is where the power quality (PQ) requirements will be met. Voltage flicker and harmonic distortion requirements are evaluated from the POC between the Requester and AEP's system.

Voltage Flicker Criteria

The random voltage fluctuations (flicker) measured at the POC directly attributable to the Requester, must remain within the limits specified in IEEE Standard 1453-2015 *IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems*.

Harmonic Distortion Criteria

AEP requires that the Requester's operation comply with IEEE Standard 519-2014, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*.

Electrical Interactions

If field measurements, analytical studies or customer complaints indicate likely adverse electrical interactions (e.g., resonance) between the connected facility and the AEP system, AEP and the Requester will collaborate to determine the nature and extent of the electrical interaction.

Compliance and Monitoring

AEP reserves the right to monitor the Requester for the electric distortions referenced in this section, or any other electrical distortions that would be relevant or complementary, at the determined POC. AEP will determine the Requester's compliance with these criteria.

AEP may permit the Requester to operate above some of the criteria stated in applicable IEEE standards until AEP receives complaints from other customers or other operating problems arise for AEP. By so agreeing, AEP does not waive any rights it may have to strictly enforce its established criteria as measured or calculated in the future.

The Requester agrees that if the operation of its facility and equipment result in voltage flicker or harmonic distortions in excess of AEP's criteria, it is the Requester's responsibility to take action to comply with such criteria. Corrective measures could include, but are not limited to, modifying production methods, materials, or installing mitigation equipment necessary to bring the Requester's operations into compliance.

6.13 Operational Issues

Emergency Operation

The Requester must have AEP-approved procedures in place when connecting to AEP. If the Requester's facility is part of any AEP emergency procedures (e.g., Conservative Operations), then the Requester must follow applicable procedures during a system emergency.

Black Start Capability

AEP may use the Requester's generation black start capability. If deemed appropriate for a particular installation, this option will be addressed in the applicable Interconnection Agreement. Factors include the Requester's generation location and other considerations applicable to system restoration in the event of a local or widespread blackout.

If a blackout occurs, the *AEP Black Start Plan* must be followed to aid in system restoration. The Requester must comply with the black start requirements in applicable NERC Reliability Standards. If the Requester's generation becomes completely de-energized or retired, the Requester must advise AEP and the applicable RTE of this status.

In addition to the potential black start capability requirements, the Requester's generation may need the capability to operate at low output levels, and participate in system frequency and/or voltage control as required.

Sub-Synchronous Torsional Interactions or Resonance

Depending on the generation facility's location in the transmission network, close electrical proximity to series compensated transmission lines or Flexible AC Transmission Systems (FACTS) devices may result in undesirable or damaging sub-synchronous currents. Also, the provision of high speed reclosing following transmission line faults may result in excessive torsional duties. The Requester shall provide AEP with immunity from damaging torsional oscillations resulting from all transmission system operations, and ensure the turbine-generator is not excited into resonance by normal system operations.

Frequency and Voltage Ride-Through Capability

The Requester's generation must have frequency and voltage ride-through capability and adhere to applicable NERC and RTE standards or criteria. Requesters must set their applicable generator protective relays such that generating units remain connected during frequency and/or voltage excursion defined in *NERC PRC-024-2*[36]. AEP will also determine the clearing time requirement at the point of interconnection using AEP relaying standards, and document the requirement, as necessary, in the initial or amended Interconnection Agreement.

6.14 Communications & Procedures During Normal and Emergency Operating Conditions

The Requester will direct all switching, outage requests, and maintenance activities affecting the Requester-AEP interface to the appropriate AEP Energy Delivery Operations Center, which is responsible for reviewing, scheduling, and coordinating transmission facility outages and switching. The Requester must provide AEP and the RTE (if applicable) advanced written notice of a planned outage that may affect AEP's operational reliability. The Requester must follow all applicable outage coordination procedures[37].

In accordance with AEP's *Transmission Outage Management System (TOMSS) Business Rules*[38], the Requester will provide at least 30 days advance notice for an outage request except for momentary outages or low-risk, planned maintenance less than 30 minutes in duration. However, the applicable 30-day period may be extended, depending on the RTE. AEP must review and approve outage plan changes that occur less than 30 days before the outage date, which could affect the overall outage risk, on a case-by-case basis. On the switching date, the Requester's operator must contact AEP Energy Delivery Operations before the switching or planned maintenance activity begins.

If the requested outage creates an abnormal condition that could affect AEP system reliability and/or customer reliability, the Requester shall mitigate all identified risks and share its restoration plan with AEP.

If a planned outage affects the protection system(s) resulting in a reduced or inadequate protection scenario on an inter-tie line, the Requester must follow the *AEP Failure or Disabling of Protection Systems Procedure*[39] for proper outage notification. In addition, the Requester must coordinate all switching of its load and backup generation with the local AEP Energy Delivery Operations Center.

For an unplanned outage or maintenance that may affect AEP transmission operation reliability, the Requester must submit the forced outage to AEP and the RTE (if applicable) as soon as practical, and provide updates whenever new information is received. Appropriate communication protocols must be followed according to *AEP Transmission Operations Reliability Communication Protocol*[40],

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[36] NERC, PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings, 7/1/2016
[37] AEP Energy Delivery Operations, Outage Coordination Procedure, TOPS.01.013.00 PRO, Rev. 12, 7/31/2020
[38] AEP Energy Delivery Operations, Transmission Outage Management Strategy System (TOMSS) Business Rules and Process, Rev 3.0.0, 7/1/2020
[39] AEP Transmission, Failure or Disabling of Protection Systems Procedure, Rev. 3, 4/1/2018
[40] AEP Energy Delivery Operations, Reliability Communication Protocol Guideline, TOPS.01.053.00_GUI, 8/28/2020

AEP Transmission Operations Real-time Data Integrity Guideline[41], and the SCADA *Station Quality Procedure*[42].

This communications protocol does not replace any existing agreements between AEP and the Requester. If any conflicts exist between documents, the binding agreements take precedence.

6.15 Underfrequency Load Shedding

The Requester must install under frequency relays and shed load as outlined in the applicable RTE Load Shedding Guides.

[41] AEP Energy Delivery Operations, Real-time Data Integrity Guideline, TOPS.01.015.00_GUI, Rev. 2.0, 7/2/2020
[42] AEP Energy Delivery Operations, SCADA Station Quality Procedure, Rev. 0, 4/1/2018

7.0 Maintenance

The following subsections outline the requirements associated with facility maintenance, including ownership, cost, maintenance, compliance, and maintenance coordination.

7.1 Ownership, Cost, Maintenance, and Compliance

The Requester will install, operate and maintain in good order and repair, and without cost to AEP, all facilities that AEP requires for the safe operation of the Requester's facilities connected to AEP. At all times, the Requester's facilities must conform to good utility practice, National Electrical Safety Code (NESC), RTE requirements, NERC Reliability Standards, National Electric Code, and applicable laws and regulations. Any electrical facility operated as a part of the transmission grid must have the ownership, cost, maintenance, NERC, and RTE compliance responsibilities outlined in the IA or Interconnection and Local Delivery Service Agreement (ILDSA).

7.2 Maintenance Coordination

Maintenance Coordination requirements can be determined on an as needed basis with communication between AEP and the interconnecting parties.

Appendix A – Definitions

Interconnection Requirements Acronyms and Terms	
Acronym/Term	**Definition**
AEP	In this document, AEP refers to the AEP Transmission business unit and associated assets.
	American Electric Power – A major investor-owned electric utility in the United States, delivering electricity to more than five million customers in 11 states. AEP ranks among the nation's largest generators of electricity, and owns the nation's largest electricity transmission system.
AEP Station Service Power	The power consumed within the AEP-owned station to supply substation equipment.
ANSI	American National Standards Institute
Area Electric Power System	Electrical network of the transmission utility provider delivering/transporting electric power to load (Local EPS). See the *IEEE Standard 1547™ 2003 Glossary* for reference.
auxiliary load	A generator's auxiliary power consumption – also referred to as Auxiliary Load, and is provided through the Local Electric Power System owner, otherwise called the load serving entity (LSE).
BCT	bushing current transformer
BES	Bulk Electric System
CT	current transformer – A transformer used to monitor the current going through a piece of equipment. This device steps down the current to a lower level current suitable for a relay or meter input.
CVT	capacitive voltage transformer
DER	Distributed Energy Resources – A generating facility, not directly connected to the AEP transmission system, and may or may not participate in a wholesale market.
Effectively Grounded	X0/X1 less than or equal to 3 and R0/X1 less than or equal to 1 (IEEE definition)
EHV	extra-high voltage – Transmission lines rated 765kV, 500kV, and 345kV, and transformers with secondary voltages at or above 345kV, are considered extra-high voltage (EHV) facilities, and are referred to as *EHV facilities* in this document. These facilities are part of the BES. In some cases, from a design perspective, AEP may treat some facilities as *EHV* while they might not meet that voltage threshold.

EPS	1. Electric Power System – A network of electrical components that supply, transfer, and use electric power. 2. ERCOT Polled Settlement – The ERCOT-required metering facilities owned by AEP typically installed to meter the interconnection between AEP and the GC Requester.
ERCOT	Electric Reliability Council of Texas – An ISO managing the flow of electric power to about 90% of the state's electric load. ERCOT performs financial settlements for the competitive wholesale bulk-power market. See RTE.
EUC	End-User Connection – New or materially modified connection that consumes all of the energy delivered or ultimately delivers the power to individual users. A delivery point (DP) or point of delivery (POD) is associated with this type of connection and power is expected to flow in one direction, from the AEP transmission system to the EUC Requester. Examples of this connection type are industrial facilities and other load-serving entities, such as electric cooperatives and municipals. Nothing herein should be construed to imply the provision of electric service directly to any retail consumer.
facility	A set of electrical equipment that operates as a single electric system element (e.g., a line, a generator, a shunt compensator, transformer).
FERC	Federal Energy Regulatory Commission
GC	Generator Connection – New or materially modified (affiliated or non-affiliated) connection for a generating facility, typically connected directly to the AEP transmission system, with the intention of participating in a wholesale market.
Generator Station Service Power	A generator's auxiliary power consumption – Also referred to as Auxiliary Load, and is provided through the Local Electric Power System owner, otherwise called the load serving entity (LSE).
GPR	ground potential rise
HV	high voltage – Transmission lines typically rated 230kV, 161kV, and 138kV, and transformers with secondary voltages above 100kV but below 345kV are considered High Voltage (HV) facilities, and are referred to as **HV facilities** in this document. These facilities are part of the BES.
HVP	high-voltage protection
IA	Interconnection Agreement – A legal document specifying terms and conditions for connecting AEP and Requester facilities.
ICCP	Inter-control Center Communications Protocol
IEEE	Institute of Electrical and Electronics Engineers

ILDSA	Interconnection and Local Delivery Service Agreement – A FERC jurisdictional agreement that defines a non-affiliate wholesale customer's physical delivery point interconnections to the AEP system that also contains rates/charges for AEP-provided wholesale distribution services not included in an RTO's Open Access Transmission Tariff (OATT).
IPP	Independent Power Producer
ISO	Independent System Operator – Regional organizations responsible for administering the electric transmission grid. See RTE.
kVA	Kilovoltampere
kVAR	Kilo Volt Ampere Reactive
kWh	Kilowatt-hour
Local Electric Power System	Local Electric Power System (EPS): 1. Affiliate wholesale electric distribution network/system/premises 2. Non-affiliate wholesale electric distribution network/system/ premises 3. Local electric power system is contained entirely with a single premises or group of premises. See the I*EEE Standard 1547™-2003 Glossary* for reference.
looped connection	A connection that is capable of receiving power from two (or more) directions.
LSE	load serving entity – The LSE is also the owner of the Local EPS system.
material modification	Any modification to facilities connected to, or in the process to be connected to AEP, that requires work to be executed on the AEP system or the contract in place for the connecting facility. This includes generation connections requested within an RTO generation interconnection queue and the potential impact of a modification on other requests with a later queue position.
MISO	Midcontinent Independent System Operator – A regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 15 U.S. states and the Canadian province of Manitoba. See RTE.
MLSE	Most Limiting Series Element. All series elements that together make up a line section, or substation transformer circuit, are reviewed to determine which element has the most limiting rating. The most limiting element will determine the normal and emergency ratings of the facility.
MOAB	motor operated air break
MW	Megawatt – One million watts

NEC	National Electric Code as approved by the American National Standards Institute (ANSI).
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
OATT	Open Access Transmission Tariff
OpCo	Operating Company – AEP's regional operating companies that directly serve distribution customers.
OPGW	optical ground wire – A type of shield wire that contains a set of optical fibers for communication.
OTB	option to build – A process whereby a Requester may have the option to assume responsibility for the design, procurement, and construction of certain facilities, which upon completion are typically transferred to AEP per terms of an applicable agreement.
P&C	protection and control
pilot protection systems	A system that uses communication channels to send information from the local relay terminal to the remote relay terminal thereby allowing high-speed tripping for faults occurring within 100% of the protected line.
PJM	PJM Interconnection – A regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. See RTE.
POC	point of compliance
POI	point of interconnection
PQ	power quality
PT	potential transformer – A transformer used to monitor the voltage on a piece of equipment. This device reduces voltages to a lower level that is compatible for input into a relay or meter. The IEEE industry standard terminology for this is voltage transformer (VT).
radial	A substation or load being served by a single transmission source and can include substations with downstream DER or with batteries used as a transmission asset to support the substation during emergency scenarios.
RBS	rated breaking strength
Requester	In this document, Requester is defined as the entity requesting a new or materially modified interconnection and applies to the following: • Distributed Energy Resource Connection (DER) • End-User Connection (EUC) • Generator Connection (GC)

	• Transmission Interconnection (TI)
RTE	regional transmission entity – For the purpose of this document, any regional body having jurisdiction over a party, including the applicable RTO, ISO, or regional electric reliability organization under NERC authority.
RTO	Regional Transmission Organization – An organization that is responsible for moving electricity over large interstate areas. They coordinate, control, and monitor an electricity transmission grid. See RTE.
RTU	remote terminal unit – A device used for remote monitoring and control by sending telemetry data to SCADA or other industrial control systems.
SCADA	Supervisory Control and Data Acquisition – A system that collects, processes, and communicates real-time information back to a dispatch center, and provides remote control capability.
SIS	System Interconnections Services
SPP	Southwest Power Pool – A regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 17 states. See RTE.
SS Guides	Station Standards Guides – A set of AEP transmission standards that is available upon request with AEP approval.
SWPPP	Storm Water Pollution Prevention Plan
TCR	Transmission Construction Representative
TI	Transmission Interconnection – New or materially modified connection to the AEP transmission system from a non-affiliate power system, where power is expected to flow in either direction. These connections are often referred to as wires-to-wires interconnections, network interconnections, transmission-to-transmission interconnections, or interconnections. An example of a TI is connecting the AEP transmission grid to the transmission system of a neighboring utility.
TLES	Transmission Line Engineering Standards – A set of AEP transmission standards that is available upon request with AEP approval.
VAC	volts alternating current
VT	voltage transformer

Appendix B – Requester Information Requirements

B.1 GC and DER Information Requirements Form

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY™

Distributed Energy Resources (DER) Generation Connections (GC)

Generator Request Form Checklist

If the requirement is marked with:

- DER OH – The data is needed for DER facilities located within Ohio.
- DER Non-OH – The data is needed for DER facilities not located within Ohio.
- GC – The data is needed for all GC connections.

If the information was already provided during an earlier stage of study and has not changed, it does not need to be provided for later stages.

		Feasibility Study	Impact Study	Facilities Study	Combined Study
A	**Contact Information**				
A.1	Requester Name	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.2	Requester Title	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.3	Requester Address	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.4	Requester Phone	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.5	Requester Email	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.6	Technical Lead Name	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.7	Technical Lead Title	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.8	Technical Lead Phone	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
A.9	Technical Lead Email	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
B	**Project Schedule**				
B.1	Requested Generation Connection In-Service Date	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C	**Project Scope**				
C.1	Detailed Request Description	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C.2	AEP Asset that Customer's Facility Will Be Connected to	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C.3	Electric Distribution Company	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C.4	GPS Coordinates for the Point of Interconnection (POI)	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C.5	Requested Voltage Class	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
C.6	RTO Queue Number (if applicable)	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
D	**Modeling Information**				
D.1	Characteristics of the Generator	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
D.2	Unit Capability Data	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
D.3	Unit Transformer Data	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
E	**Detailed Data**				
E.1	Unit Generator Dynamics Data		DER OH & GC	DER OH & GC	DER Non-OH
F	**Drawings, Diagrams, and Maps**				
F.1	Site Plan	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
F.2	One-Line Drawing of Facility	DER OH & GC	DER OH & GC	DER OH & GC	DER Non-OH
F.3	Three-Line Drawing of Generation System			DER OH & GC	DER Non-OH
F.4	Elementary Drawings			DER OH & GC	DER Non-OH

Distributed Energy Resources (DER) / Generation Connections (GC)

Go through the Checklist above to determine what information is required to be submitted to the respective RTO/Affiliate OpCo and/or respective AEP mailbox.

Generator Request Form

Clear Form

Add Attachments

Contact Information (Requester)

Date
Customer Name
Customer Address
Name
Job Title
Phone
Email

Attachments	Included	Future	N/A
Site Plan[iv]			
One-Line Drawing of Facility[v]			
Three-Line Drawing of Gen. System[vi]			
Elementary Drawings[vii]			
System Modeling Data[viii]			
Project Schedule			

Contact Information (Technical Lead)

Name
Job Title
Phone
Email

Questions Based on Request

Is customer's facilities currently connected to AEP system?[i]

Type of Energy Source[ii]

Type of Generator (Synchronous, Induction, Inverter, etc…)[iii]

Is this a modification of an existing Generation facility?

If so, which facility?

Request Information

Requested Generation Connection In-Service Date

Electric Distribution Company[ix]

County Name

Proposed Location (with GPS Coordinates) for POI

Request Description

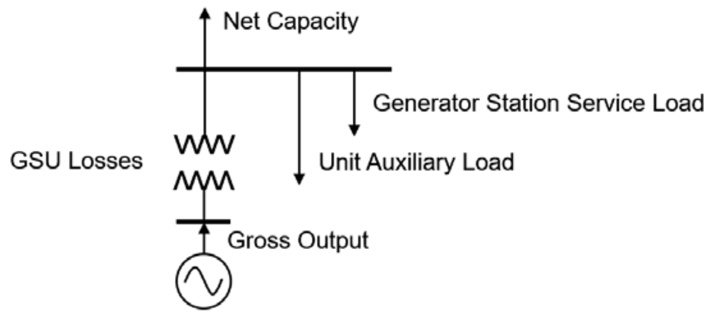
Voltage Class (kV)

Connected to Which AEP Asset?

RTO Queue Number (if applicable)

The Generating Equipment is intended to be used for:
(Emergency/Standby, Peak Shaving, Wholesale Market Participation, etc.)

Unit Capability Data[x]



Net Capacity = (Gross Output – GSU Losses – Unit Auxiliary Load – Generator Station Service Load

Season	**Max/Min**	**Data Point**	**Data**
Summer 92°F ambient air temperature	**Max**	Net Capacity (MW)	
		Unit Auxiliary Load (MW/MVAR)	
		GSU Losses (MW)	
		Gross Output (MW)	
	Min	Net Capacity (MW)	
		Unit Auxiliary Load (MW/MVAR)	
		GSU Losses (MW)	
		Gross Output (MW)	
Winter 30°F ambient air temperature	**Max**	Net Capacity (MW)	
		Unit Auxiliary Load (MW/MVAR)	
		GSU Losses (MW)	
		Gross Output (MW)	
	Min	Net Capacity (MW)	
		Unit Auxiliary Load (MW/MVAR)	
		GSU Losses (MW)	
		Gross Output (MW)	
		Generator Station Service Load (MW/MVAR)	
		Estimated Annual Energy Production (MWh)	
		Gross Reactive Power Capability at Max Gross Output (Leading & Lagging)	

Unit Generator Dynamics Data[xi]

MVA Base	
Nominal Power Factor	
Terminal Voltage (kV)	

Unsaturated Reactances (on MVA Base)

Direct Axis Synchronous Reactance	
Direct Axis Transient Reactance	
Direct Axis Sub-transient Reactance	
Quadrature Axis Synchronous Reactance	
Quadrature Axis Transient Reactance	
Quadrature Axis Sub-transient Reactance	
Stator Leakage Reactance	
Negative Sequence Reactance	
Zero Sequence Reactance	
Saturated Sub-transient Reactance	
Armature Resistance	

Time Constraints (seconds)

Direct Axis Transient Open Circuit	
Direct Axis Sub-transient Open Circuit	
Quadrature Axis Transient Open Circuit	
Quadrature Axis Sub-transient Open Circuit	
Inertia, H (kW-sec/kVA, on KVA Base)	
Speed Damping, D	
Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]	

IEEE Dynamic Model Parameters

Governor Model	
Exciter Model	
Power System Stabilizer Model	

Unit Transformer Data[xii]

Data Points	Data
# of Transformers	
Transformer MVA Base	
# of Transformer Windings	
Transformer Winding Impedance (R+jX, on transformer MVA Base) – High to Low	
Transformer Winding Impedance – High to Tertiary	
Transformer Winding Impedance – Low to Tertiary	
Transformer Rating (MVA)	
Transformer Low-side Voltage (kV)	
Transformer High-side Voltage (kV)	
Transformer Tertiary Voltage (kV)	
Transformer Winding Types (High-Low-Tertiary)	
Transformer Off-nominal Turns Ratio	
Transformer Number of Taps and Step Size	

Endnotes

[i] If yes, provide one-line diagram of existing connection arrangement with existing meter locations identified. Identify meter type (e.g., kWH revenue).

[ii] List what type of energy source/primary fuel type the generator is for this request: Solar, Wind, Hydro, Diesel, Natural Gas, Fuel Oil, Nuclear, Other (please specify).

[iii] Specify the type of technology used for the type of generator (steam turbine, combustion turbine, combined/simple cycle, etc.)

[iv] Plot plan or description showing the exact location and orientation of proposed facilities and point of electric service delivery. Note: AEP has specific guidelines for site selection and must approve the interconnection substation location and design – refer to Section 3.5.

[v] One-line diagrams shall include:

1. Equipment names and/or numerical designations for all circuit breakers, switches, transformers, generators, etc., associated with the generation.
2. Power Transformers – name or designation, nominal kVA, nominal primary, secondary, tertiary voltages, vector diagram showing winding connections, tap settings, and transformer impedance. A copy of the transformer nameplate and test report that includes both positive and zero sequence impedance information will ultimately be required.
3. Station Service Transformers – Designate phase(s) connected and estimated kVA load.
4. Instrument Transformers – Voltage and current, phase connections.
5. Surge Arresters/Gas Tubes/Metal Oxide Varistors/Avalanche Diode/Spill Gaps/ Surge Capacitors, etc. – Type and Ratings.
6. Capacitor Banks – kVAR rating.

7. Disconnect Switches – Indicate status normally open with a (N.O.) and whether manual or motor operated. Include switch voltage, continuous and interrupting ratings.
8. Circuit Breakers – Interrupting rating, continuous rating, operating times.
9. Generator(s) – Include nameplate, test report, type, connection, kVA, voltage, current, rpm, PF, impedances, time constraints, etc.
10. Point of Interconnection to power delivery system and phase identification.
11. Fuses – Manufacturer, type, size, speed, and location.

[vi] Three-line diagrams shall include, same as ii.

[vii] Provide potential and current drawings associated with the protection and control schemes for the generator and interconnection equipment. The drawings should include:

1. Terminal designation of all devices – relay coils and contacts, switches, transducers, etc.
2. Relay functional designation – per latest ANSI standard. The same functional designation shall be used.
3. Complete relay type (such as CV-2, SEL321-1, REL-301, IJS51A, etc.).
4. Switch contact shall be referenced to the switch development if development is shown on separate drawing.
5. Switch developments and escutcheons shall be shown on the drawing where the majority of contacts are used. Where contacts of a switch are used on a separate drawing, that drawing should be referenced adjacent to the contacts in the switch development. Any contacts not used should be referenced as spare.
6. All switch contacts are to be shown open with each labeled to indicate the positions in which the contract will be closed. Explanatory notes defining switch coordination and adjustment where mid-adjustment could result in equipment failure or safety hazard.
7. Auxiliary relay contacts shall be referenced to the coil location drawing if coil is shown on a separate drawing. All contacts of auxiliary relays should be shown and the appropriate drawing referenced adjacent to the respective contacts.
8. Device auxiliary switches (circuit breakers, contactor, etc.) should be referenced to the drawing where they are used.
9. Any interlocks (electromechanical, key, etc.) associated with the generation or interconnection substation.
10. Ranges of all timers and setting if dictated by control logic.
11. All target ratings; on dual ratings note the appropriate target tap setting.
12. Complete internal for electromechanical protective relays. Microprocessor type relays may be shown as a “black box,” but manufacturer’s instruction book number shall be referenced and terminal connections shown.
13. Isolation points (state links, PK-2 and FT-1 blocks, etc.) including terminal identification.
14. All circuit elements and components, with device designation, rating and setting where applicable. Coil voltage is shown only if different from nominal control voltage.
15. Size, type, rating and designation of all fuses.
16. Phase sequence designation as ABC or CBA.
17. Potential transformers – nameplate ratio, polarity marks, rating, primary and secondary connections (see Requirements for minimum ratings). Current transformers (including aux. CT’s) – polarity marks, rating, tap ratio and connection.

[viii] Modeling data must be supplied to AEP and/or the RTO/ISO to allow necessary interconnection studies to be performed. It is recognized that some of this data may initially be preliminary in nature. Interconnection studies will be based on data submitted. Changes or modifications to this data after the interconnection study has been completed may render the analysis invalid and require re-opening of the interconnection study. It is the Requester’s responsibility to make AEP and/or the RTO/ISO aware of changes to this data, and to provide final certified test reports and modeling data as soon as it is available.

[ix] Locate your EDC on your respective Public Utilities Commission (PUC) website for electric service area based on location.

[x] Provide all information regarding the expected unit capability. Make sure you submit the Reactive Capability Curve.

[xi] Provide all generator dynamics data about the unit. Make sure you submit the generator certified test report information.

[xii] Provide all transformer data about the unit. Make sure you submit the transformer test report information. Note: GSU/Collector step up transformer manufacturer’s certified test report must include positive- and zero-sequence impedances between all windings (including tertiary). Also, indicate whether the transformer is shared with other units.

B.2 EUC Information Requirements Form

End-User Connection (EUC)

New or Material Modification Request Form

Upon completion of the form and inclusion of all required details, please email to the inbox for the RTO in which you are located, as outlined in Section 2.1.1.

Clear Form

Add Attachments

Contact Information

Date (MM/DD/YYYY)	
Customer Name	
Customer Address	
Requester Name	
Requester Job Title	
Requester Phone	
Requester Email	

Attachments	Included	Future	N/A
Site Plan[i]	☐	☐	☐
One-Line Drawing of Facility[ii]	☐	☐	☐
System Modeling Data[iii]	☐	☐	☐

Questions

Do you have an existing contract with AEP?

If yes, who is your AEP Customer Account Manager?

What is your Service Contract # (if applicable)?

What type of load are you connecting?

Is this a new or materially modified delivery point?

If load is being transferred from another location, from where?

If load is being transferred, is the existing delivery point being materially modified? (If so, provide details)

Request Information

What is the target In-Service Date (ISD)?

Which AEP Operating Company (OpCo) is this delivery point located within?

What are the GPS coordinates of the delivery point?

What is the voltage class (kV) of the asset in which you are requesting to connect?

To which AEP asset are you requesting connection?

Please describe your request in further detail:

Load Ramp Schedule

Load Ramp Schedule Step [iv]	Description of Step	Normal Demand (MW)	Anticipated Peak Demand (MW)	Anticipated Power Factor (%)	Anticipated Load Factor (%)
Ultimate					

Is Load Seasonal or Flat?

Motor Information[v]

Motor Description[vi]	Size (hp)	Motor Code/Locked Rotor Current	Efficiency	Voltage on the Motor Side (kV)	Starting Power Factor	Running Power Factor	VFD?

Flicker Requirements

Delivery Point Descriptions[vii]

a) Please explain the planned high-side protection device(s) and relaying scheme, including manufacturer, type, voltage rating, and current rating of each device:

b) If utilizing fuse protection on the transformer(s), please provide the details of that device[viii]:

c) Please explain the power transformer(s) connection type[ix] and details of the unit(s):

d) Please explain the planned low-side protection device(s) and scheme, including all data on fuses, breakers, relays, and relay settings:

e) Please explain, if applicable, the size and the amount of fixed or switched capacitors or other power factor correction equipment and methods that will be utilized for operation:

f) Please explain the maximum magnitudes (MW & MVAR) of sudden load swings at the point of common coupling and the number of fluctuations per second, minute, or hour:

g) Please explain the maximum expected demand (MW & MVAR) at the point of interconnection (if different than indicated in the load ramp schedule):

h) Please provide data on the harmonic and sub-harmonic current/voltage spectra of the equipment to be installed under three-phase balanced and unbalanced conditions:

i) Please provide, if applicable, data on SVC (other FACTS or similar devices) and harmonic filters:

j) Please explain if this request is for the connection of a distribution system with high fault currents:

k) Please explain any special needs or requests:

Endnotes

[i] Plot plan or description showing the exact location and orientation of proposed facilities and point of electric service delivery.
[ii] Including high-side protection device(s), transformer, low-side protection device(s), and electrical configuration of the connection to the facility
[iii] Modeling data must be supplied to AEP and/or the RTO/ISO to allow necessary interconnection studies to be performed. It is recognized that some of this data may initially be preliminary in nature. Interconnection studies will be based on data submitted. Changes or modifications to this data after the interconnection study has been completed may render the analysis invalid and require re-opening of the interconnection study. It is the EUC Requester’s responsibility to make AEP and/or the RTO/ISO aware of changes to this data, and to provide final certified test reports and modeling data as soon as it is available.
[iv] Include all steps of the anticipated load ramp, as necessary. Include, at a minimum, the first 5 years following in-service. Please include normal and peak demand in each perspective year.
[v] An additional survey may be required for detailed motor information. This relates to specific data related to motor loads and their protection settings as well as uninterrupted power supply back up information. This information will be collected in the form of an Electric Power Research Institute load survey spreadsheet to be filled out by the Requester. A copy of this survey can be provided by the Advanced Transmission Studies and Technology (ATST) department at AEP, if deemed necessary.
[vi] Include all motors and all the corresponding details regarding the motor.
[vii] Provide detailed descriptions of connection to AEP Transmission system.
[viii] AEP has specific requirements on when fuse style protection can be utilized, please refer to Section 3.1.1 of the Connection Requirements for details
[ix] AEP has specific requirements for the type of transformer connections allowed, please refer to Sections 3.1.1 and 4.4.1 of the Connection Requirements for details. Details needed of the unit(s) include: manufacturer’s nameplate, serial number, available voltage taps, MVA ratings, high and low winding connections, low-side grounding (if used), and impedance test report data that includes percent impedance for both positive and zero sequence (primary-secondary1, primary-secondary2, secondary1-secondary2).

B.3 TI Information Requirements Form

Upon completion of the form and inclusion of all required details, please email to the inbox depending on the RTO in which you are located, as outlined in Section 2.1.1.

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY™

Transmission Interconnection (TI)

New or Material Modification Request Form

Clear Form

Add Attachments

Contact Information

Date (MM/DD/YYYY)	
Customer Name	
Customer Address	
Requester Name	
Requester Job Title	
Requester Phone	
Requester Email	

Attachments	Included	Future	N/A
Site Plan[1]	☐	☐	☐
One-Line Drawing of Facility[2]	☐	☐	☐

Request Information

Requested In-Service Date

GPS Coordinates of Requested Interconnection

Voltage Class (kV)

To which AEP asset will the interconnection be connected?

What is your Service Contract # (if applicable)?

Comment(s)/Description

Request Description

Additional Comment(s)

[1] Plot plan or description showing the exact location and orientation of proposed facilities and point of interconnection.

[2] Including protection device(s) and electrical configuration of the connection.

<u>EXHIBIT 2</u>

Summary of Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy	
(1)	Annual kWh	1,971,000,000
(2)	DA LMP $/kWh	0.03890
(3) =(1)*(2)	Marginal Costs - Energy	$76,674,933
	Marginal Costs - Distribution	
(4)	Distribution WO Total	$4,801,185
(5)	Levelized Carrying Cost	10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost	$487,230
	Summary of Incremental Costs and Revenues	
(7)	Energy	$76,674,933
(8)	Distribution	$487,230
(9)	PJM LSE Transmission	$28,626,639
(10)	Generation Capacity	$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs	$105,788,801
(12)	Incremental Revenue	$124,643,645
(13) =(12)-(11)	**Net Revenue (Cost)**	**$18,854,844**