Generation Interconnection Feasibility Study Report

For

PJM Generation Interconnection Request Queue Position AD1-149

Carbondale 69 kV

May 2018

Preface

The intent of the feasibility study is to determine a plan, with ballpark cost and construction time estimates, to connect the subject generation to the PJM network at a location specified by the Interconnection Customer. The Interconnection Customer may request the interconnection of generation as a capacity resource or as an energy-only resource. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: (1) Direct Connections, which are new facilities and/or facilities upgrades needed to connect the generator to the PJM network, and (2) Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system.

In some instances a generator interconnection may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection, may also contribute to the need for the same network reinforcement. The possibility of sharing the reinforcement costs with other projects may be identified in the feasibility study, but the actual allocation will be deferred until the impact study is performed.

The Feasibility Study estimates do not include the feasibility, cost, or time required to obtain property rights and permits for construction of the required facilities. The project developer is responsible for the right of way, real estate, and construction permit issues. For properties currently owned by Transmission Owners, the costs may be included in the study.

General

The Interconnection Customer (IC), proposes to install PJM Project #AD1-149, a 19.90 MW (8.33 MW Capacity) solar/storage hybrid facility in, Kanawha County, WV. The primary point of interconnection is a direct connection to AEP's Carbondale 69 kV Substation (see Figure 1).

The requested in service date is June 30, 2019.

The objective of this Feasibility Study is to determine budgetary cost estimates and approximate construction timelines for identified transmission facilities required to connect the proposed generating facilities to the AEP transmission system. These reinforcements include the Attachment Facilities, Local Upgrades, and Network Upgrades required maintaining the reliability of the AEP transmission system. Stability analysis is not included as part of this study.

This is an atypical hybrid installation. The IC will need to be aware of the Market participation rules for both the Battery and the Solar. Separate Revenue Metering will be required for each resource as well as limitations on the battery while participating in the Regulation market. There must be clear separation of the retail service and the wholesale transactions being made by the plant being operated in Hybrid mode, as a battery, and a solar resource.

A waiver to operate the Battery as a Capacity resource will also be required. The IC will need to specify how the plant should be studied during the System Impact Study phase by following the most current guidelines below:

If it is intended that the project (when completed) will participate in the regulation markets, only half the stockpile can be considered; If the project will not participate in the regulation market, then the full stockpile will be considered.

If IC is not participating in the regulation markets, then 39.8 MWH should be the starting point.

If the IC is participating in the regulation markets, then 19.9 MWH should be the starting point.

Note that under the Capacity Performance (CP) rules, for all generators, if a CP alert is called, must be capable of delivering their offered capacity for a continuous 24 hours. Exceptions to this can be requested from both the Independent Market Monitor (IMM) and PJM, but are not guaranteed.

The CP parameter limits are located at this link:

http://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx

If the project does not request an exception, then it can receive 39.8 MWH/24 hours or 1.66 MWC

If the project gets an exception (say 10 hours), then it can receive 39.8 MWH/10 Hours or 3.98 MWC.

The IC will need to confirm their CIR selections to fall within the limits stated above and complete the System Impact Study Data submission in Queue Point accordingly.

Note that the operation of this hybrid solar/storage facility is outside the scope of this Feasibility Study and will need to be well defined during later study phases.

Attachment Facilities

Point of Interconnection (Carbondale 69 kV Substation)

To accommodate the interconnection at the Carbondale 69 kV substation, the substation will have to be expanded requiring the installation of one 69 kV circuit breaker (see Figure 1). Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required.

Direct Connection at the Carbondale 69kV Substation work and cost:

- Expand the substation requiring the installation of one (1) new 69kV circuit breaker (see Figure 1). Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required (see Figure 1).
    - **Estimated Station Cost: 600,000**

Non-Direct Connection Cost Estimate

The total preliminary cost estimate for Non-Direct Connection work is given in the following table below:

For AEP building Non-Direct Connection cost estimates:

Description	Estimated Cost
69 kV Revenue Metering	**$200,000**
Upgrade line protection and controls at the Carbondale 69 kV substation.	**$200,000**
Total	**$400,000**

Table 1

Interconnection Customer Requirements

It is understood that the Interconnection Customer's (IC) responsible for all costs associated with this interconnection. The cost of the IC's generating plant and the costs for the line connecting the generating plant to the Carbondale 69 kV substation are not included in this report; these are assumed to be the IC's responsibility.

The Generation Interconnection Agreement does not in or by itself establish a requirement for American Electric Power to provide power for consumption at the developer's facilities. A separate agreement may be reached with the local utility that provides service in the area to ensure that infrastructure is in place to meet this demand and proper metering equipment is

installed. It is the responsibility of the developer to contact the local service provider to determine if a local service agreement is required.

Requirement from the PJM Open Access Transmission Tariff:

1. An Interconnection Customer entering the New Services Queue on or after October 1, 2012 with a proposed new Customer Facility that has a Maximum Facility Output equal to or greater than 100 MW shall install and maintain, at its expense, phasor measurement units (PMUs). See Section 8.5.3 of Appendix 2 to the Interconnection Service Agreement as well as section 4.3 of PJM Manual 14D for additional information.

2. The Interconnection Customer may be required to install and/or pay for metering as necessary to properly track real time output of the facility as well as installing metering which shall be used for billing purposes. See Section 8 of Appendix 2 to the Interconnection Service Agreement as well as Section 4 of PJM Manual 14D for additional information.

Revenue Metering and SCADA Requirements

PJM Requirements

The Interconnection Customer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for IC's generating Resource. See PJM Manuals M-01 and M-14D, and PJM Tariff Sections 24.1 and 24.2.

AEP Requirements

The Interconnection Customer will be required to comply with all AEP Revenue Metering Requirements for Generation Interconnection Customers. The Revenue Metering Requirements may be found within the "Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System" document located at the following link:

http://www.pjm.com/~/media/planning/plan-standards/private-aep/aep-interconnection-requirements.ashx

Network Impacts

The Queue Project AD1-149 was evaluated as a 19.9 MW (Capacity 8.33 MW) injection at the Carbondale 69kV substation in the AEP area. Project AD1-149 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AD1-149 was studied with a commercial probability of 53%. Potential network impacts were as follows:

Summer Peak Analysis - 2021

Generator Deliverability
(Single or N-1 contingencies for the Capacity portion only of the interconnection)

None

Multiple Facility Contingency
(Double Circuit Tower Line, Fault with a Stuck Breaker, and Bus Fault contingencies for the full energy output)

None

Contribution to Previously Identified Overloads
(This project contributes to the following contingency overloads, i.e. "Network Impacts", identified for earlier generation or transmission interconnection projects in the PJM Queue)

None

Steady-State Voltage Requirements
(Results of the steady-state voltage studies should be inserted here)

None

Short Circuit
(Summary of impacted circuit breakers)

None

Affected System Analysis & Mitigation

LGEE Impacts:

LGEE Impacts to be determined during later study phases (as applicable).

MISO Impacts:

MISO Impacts to be determined during later study phases (as applicable).

Duke, Progress & TVA Impacts:

Duke Carolina, Progress, & TVA Impacts to be determined during later study phases (as applicable).

OVEC Impacts:

OVEC Impacts to be determined during later study phases (as applicable).

Delivery of Energy Portion of Interconnection Request

PJM also studied the delivery of the energy portion of this interconnection request. Any problems identified below are likely to result in operational restrictions to the project under study. The developer can proceed with network upgrades to eliminate the operational restriction at their discretion by submitting a Merchant Transmission Interconnection request.
Only the most severely overloaded conditions are listed. There is no guarantee of full delivery of energy for this project by fixing only the conditions listed in this section. With a Transmission Interconnection Request, a subsequent analysis will be performed, which will study all overload conditions associated with the overloaded element(s) identified.

None

New System Reinforcements

(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

None

Contribution to Previously Identified System Reinforcements

(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)
(Summary form of Cost allocation for transmission lines and transformers will be inserted here if any)

None

Schedule

It is anticipated that the time between receipt of executed agreements and Commercial Operation may range from 12 to 18 months if no line work is required. If line work is required, construction time would be between 24 to 36 months after signing an interconnection agreement.

Note: The time provided between anticipated normal completion of System Impact, Facilities Studies, subsequent execution of ISA and ICSA documents, and the proposed Backfeed Date is shorter than usual and may be difficult to achieve.

Conclusion

Based upon the results of this Feasibility Study, the construction of the 19.9 MW (8.33 MW Capacity) solar/storage hybrid facility of The IC (PJM Project #AD1-149) will require the following additional interconnection charges. This plan of service will interconnect the proposed hybrid facility in a manner that will provide operational reliability and flexibility to both the AEP system and the Jesco generating facility.

Cost Breakdown for Point of Interconnection (Carbondale 69 kV)		
Attachment Cost	Expand Carbondale 69KV substation	**$600,000**
Non-Direct Connection Cost Estimate	69 kV Revenue Metering	**$200,000**
	Upgrade line protection and controls at the Carbondale 69 kV substation.	**$200,000**
	Total Estimated Cost for Project AD1-149	**$1,000,000**

Table 2

The estimates are preliminary in nature, as they were determined without the benefit of detailed engineering studies. Final estimates will require an on-site review and coordination to determine final construction requirements.

Figure 1: Primary Point of Interconnection (Carbondale 69 kV)

Single-Line Diagram