



# **Generation Interconnection**

## **Feasibility Study Report**

**for**

**Queue Project AG1-417**

**GATEWAY 69 KV**

**30 MW Capacity / 50 MW Energy**

January 2021

# Table of Contents

- 1 Introduction..... 4
- 2 Preface..... 4
- 3 General ..... 5
- 4 Point of Interconnection..... 6
- 5 Cost Summary ..... 7
- 6 Transmission Owner Scope of Work..... 8
  - 6.1 Attachment Facilities..... 8
  - 6.2 Direct Connection Cost Estimate..... 8
  - 6.3 Non-Direct Connection Cost Estimate..... 8
- 7 Schedule..... 9
- 8 Transmission Owner Analysis..... 9
- 9 Interconnection Customer Requirements..... 9
- 10 Revenue Metering and SCADA Requirements ..... 10
  - 10.1 PJM Requirements..... 10
  - 10.2 Meteorological Data Reporting Requirements..... 10
  - 10.3 Interconnected Transmission Owner Requirements..... 10
- 11 Summer Peak - Load Flow Analysis - Primary POI ..... 11
  - 11.1 Generation Deliverability ..... 12
  - 11.2 Multiple Facility Contingency ..... 12
  - 11.3 Contribution to Previously Identified Overloads..... 12
  - 11.4 Potential Congestion due to Local Energy Deliverability..... 12
  - 11.5 System Reinforcements - Summer Peak Load Flow - Primary POI..... 13
- 12 Short Circuit Analysis – Primary POI..... 14
- 13 Summer Peak - Load Flow Analysis - Secondary POI ..... 15
  - 13.1 Generation Deliverability ..... 16
  - 13.2 Multiple Facility Contingency ..... 16
  - 13.3 Contribution to Previously Identified Overloads..... 16
  - 13.4 Potential Congestion due to Local Energy Deliverability..... 16
- 14 Affected Systems ..... 17
  - 14.1 TVA..... 17
  - 14.2 Duke Energy Progress..... 17

14.3	MISO .....	17
14.4	LG&E.....	17

## 1 Introduction

This Feasibility Study has been prepared in accordance with the PJM Open Access Transmission Tariff, 36.2, as well as the Feasibility Study Agreement between the Interconnection Customer (IC), and PJM Interconnection, LLC (PJM), Transmission Provider (TP). The Interconnected Transmission Owner (ITO) is AEP.

## 2 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. Cost allocation rules for network upgrades can be found in PJM Manual 14A, Attachment B. 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 Interconnection Customer seeking to interconnect a wind or solar generation facility shall maintain meteorological data facilities as well as provide that meteorological data which is required per Schedule H to the Interconnection Service Agreement and Section 8 of Manual 14D.

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.

### 3 General

The Interconnection Customer (IC), has proposed a Solar generating facility located in Whitley County, Indiana. The installed facilities will have a total capability of 50 MW with 30 MW of this output being recognized by PJM as Capacity.

The proposed in-service date for this project is December 29, 2023. This study does not imply a TO commitment to this in-service date.

<b>Queue Number</b>	<b>AG1-417</b>
<b>Project Name</b>	<b>GATEWAY 69 KV</b>
<b>State</b>	Indiana
<b>County</b>	Whitley
<b>Transmission Owner</b>	AEP
<b>MFO</b>	50
<b>MWE</b>	50
<b>MWC</b>	30
<b>Fuel</b>	Solar
<b>Basecase Study Year</b>	2024

Any new service customers who can feasibly be commercially operable prior to June 1st of the basecase study year are required to request interim deliverability analysis.

## 4 Point of Interconnection

AG1-417 will interconnect with the AEP transmission system along one of the following Points of Interconnection:

Primary POI: Gateway 69 kV substation.

To accommodate the interconnection to the Gateway 69 kV substation, one (1) new 69 kV circuit breaker(s) will be installed (Attachment 1). Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required. AEP reserves the right to specify the final acceptable configuration considering design practices, future expansion, and compliance requirements.

Installation of the generator lead first span exiting the POI station, including the first structure outside the AEP fence, will also be included in AEP's scope. In the case where the generator lead is a single span, the structure in the customer station will be the customer's responsibility.

Secondary POI: Columbia 138 kV substation.

AG1-417 will interconnect with the AEP transmission system via a direct connection to the Columbia 138 kV substation.

To accommodate the interconnection to the Columbia 138 kV substation, one (1) new 138 kV circuit breaker(s) will be installed (Attachment 2). Installation of associated protection and control equipment, 138 kV line risers, SCADA, and 138 kV revenue metering will also be required. AEP reserves the right to specify the final acceptable configuration considering design practices, future expansion, and compliance requirements.

Installation of the generator lead first span exiting the POI station, including the first structure outside the AEP fence, will also be included in AEP's scope. In the case where the generator lead is a single span, the structure in the customer station will be the customer's responsibility.

## 5 Cost Summary

The AG1-417 project will be responsible for the following costs:

Description	Total Cost
<b>Total Physical Interconnection Costs</b>	\$1,091,000
<b>Total System Network Upgrade Costs</b>	\$0
<b>Total Costs</b>	<b>\$1,091,000</b>

This cost excludes a Federal Income Tax Gross Up charges. This tax may or may not be charged based on whether this project meets the eligibility requirements of IRS Notice 2016-36, 2016-25 I.R.B. (6/20/2016). If at a future date it is determined that the Federal Income Tax Gross charge is required, the Transmission Owner shall be reimbursed by the Interconnection Customer for such taxes.

Cost allocations for any System Upgrades will be provided in the System Impact Study Report.

The estimates provided in this report 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. In addition, Stability analysis will be completed during the Facilities Study stage. It is possible that a need for additional upgrades could be identified by these studies.

## 6 Transmission Owner Scope of Work

The total physical interconnection costs is given in the table below:

### 6.1 Attachment Facilities

The total preliminary cost estimate for the Attachment work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
69 kV Revenue Metering	\$293,000
Generator lead first span exiting the POI station, including the first structure outside the fence	\$320,000
<b>Total Attachment Facility Costs</b>	<b>\$613,000</b>

### 6.2 Direct Connection Cost Estimate

The total preliminary cost estimate for the Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
One (1) new 69 kV circuit breaker(s) will be installed at the Gateway 69 kV substation (Attachment 1). Installation of associated protection and control equipment, 69 kV line risers, and SCADA will also be required.	\$433,000
<b>Total Direct Connection Facility Costs</b>	<b>\$433,000</b>

### 6.3 Non-Direct Connection Cost Estimate

The total preliminary cost estimate for the Non-Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
Review line protection and control settings at the Gateway 69 kV substation	\$45,000
<b>Total Non-Direct Connection Facility Costs</b>	<b>\$45,000</b>

## 7 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 generally be between 24 to 36 months after signing Agreement execution.

## 8 Transmission Owner Analysis

No violations were identified in the Sub-Transmission load flow analysis and the short circuit analysis for the Sub-Transmission will be conducted in the System Impact Study phase.

## 9 Interconnection Customer Requirements

It is understood that the Interconnection Customer (IC) is responsible for all costs associated with this interconnection. The costs above are reimbursable to the Transmission Owner. The cost of the IC's generating plant and the costs for the line connecting the generating plant to the Point of Interconnection 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 the Transmission Owner 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.

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.

## 10 Revenue Metering and SCADA Requirements

### 10.1 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 Section 8 of Attachment O.

### 10.2 Meteorological Data Reporting Requirements

The solar generation facility shall provide the Transmission Provider with site-specific meteorological data including:

- Back Panel temperature (Fahrenheit) - (Required for plants with Maximum Facility Output of 3 MW or higher)
- Irradiance (Watts/meter<sup>2</sup>) - (Required for plants with Maximum Facility Output of 3 MW or higher)
- Ambient air temperature (Fahrenheit) - (Accepted, not required)
- Wind speed (meters/second) - (Accepted, not required)
- Wind direction (decimal degrees from true north) - (Accepted, not required)

### 10.3 Interconnected Transmission Owner Requirements

The IC will be required to comply with all Interconnected Transmission Owner's revenue metering requirements for generation interconnection customers located at the following link:

<http://www.pjm.com/planning/design-engineering/to-tech-standards/>

## **11 Summer Peak - Load Flow Analysis - Primary POI**

The Queue Project AG1-417 was evaluated as a 50.0 MW (Capacity 30.0 MW) injection at the Gateway 69 kV substation in the AEP area. Project AG1-417 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AG1-417 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

### **11.1 Generation Deliverability**

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

None

### **11.2 Multiple Facility Contingency**

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

None

### **11.3 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

### **11.4 Potential Congestion due to Local Energy Deliverability**

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.

Note: Only the most severely overloaded conditions are listed below. 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 shall study all overload conditions associated with the overloaded element(s) identified.

None

## 11.5 System Reinforcements - Summer Peak Load Flow - Primary POI

None.

## 12 Short Circuit Analysis – Primary POI

The following Breakers are overdutied:

None.

### **13 Summer Peak - Load Flow Analysis - Secondary POI**

The Queue Project AG1-417 was evaluated as a 50.0 MW (Capacity 30.0 MW) injection at the Columbia City 138 kV substation in the AEP area. Project AG1-417 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AG1-417 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

### **13.1 Generation Deliverability**

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

None

### **13.2 Multiple Facility Contingency**

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

None

### **13.3 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

### **13.4 Potential Congestion due to Local Energy Deliverability**

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.

Note: Only the most severely overloaded conditions are listed below. 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 shall study all overload conditions associated with the overloaded element(s) identified.

None

## **14 Affected Systems**

### **14.1 TVA**

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

### **14.2 Duke Energy Progress**

Duke Energy Progress Impacts to be determined during later study phases (as applicable).

### **14.3 MISO**

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

### **14.4 LG&E**

LG&E Impacts to be determined during later study phases (as applicable).