



**Generation Interconnection
Feasibility Study Report
for
Queue Project AF2-302
SCOTTSVILLE-COLLEEN 138 KV
12 MW Capacity / 20 MW Energy**

July 2020

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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.

An Interconnection Customer 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.

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 an update to a planned Solar generating facility located in Albemarle, Virginia. This project is an increase to the Interconnection Customer's AF1-323 project, which will share the same point of interconnection. The AF2-302 queue position is a 20 MW update (12 MW Capacity update) to the previous project. The total installed facilities will have a capability of 75 MW with 45 MW of this output being recognized by PJM as Capacity. The proposed in-service date for this update project is December 12, 2022. This study does not imply a TO commitment to this in-service date.

Queue Number	AF2-302
Project Name	SCOTTSVILLE-COLLEEN 138 KV
State	Virginia
County	Albemarle
Transmission Owner	AEP
MFO	75
MWE	20
MWC	12
Fuel	Solar
Basecase Study Year	2023

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

AF2-302 will interconnect with the AEP transmission system as an uprate to AF1-323 tapping the Scottsville to Colleen 138 kV line.

5 Cost Summary

The AF2-302 project will be responsible for the following costs:

Description	Total Cost
Total Physical Interconnection Costs	\$0
Total System Network Upgrade Costs	\$90,000
Total Costs	\$90,000

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 88-129. 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.

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 onsite 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 tables 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
	\$0
Total Attachment Facility Costs	\$0

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
	\$0
Total Direct Connection Facility Costs	\$0

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
Update Relay Settings at Scottsville 138 kV	\$45,000
Update Relay Settings at Clifford 138 kV	\$45,000
Total Non-Direct Connection Facility Costs	\$90,000

7 Incremental Capacity Transfer Rights (ICTRs)

Will be determined at a later study phase

8 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.

9 Revenue Metering and SCADA Requirements

9.1 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.

9.2 Meteorological Data Reporting Requirements

Solar generation facilities shall provide the Transmission Provider with site-specific meteorological data including:

- Back Panel temperature (Fahrenheit)
- Irradiance (Watts/meter²)
- Ambient air temperature (Fahrenheit) – (Accepted, not required)
- Wind speed (meters/second) – (Accepted, not required)

9.3 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/>

10 Summer Peak - Load Flow Analysis

The Queue Project AF2-302 was evaluated as a 20.0 MW (Capacity 12.0 MW) injection as an uprate to AF1-323 tapping the Scottsville to Colleen 138 kV line in the AEP area. Project AF2-302 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AF2-302 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

10.1 Generation Deliverability

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

None

10.2 Multiple Facility Contingency

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

None

10.3 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

10.4 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.

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC/DC	MW IMPACT
95878197	242603	05CLIFFR	138.0	AEP	242563	05BOXWD	138.0	AEP	1	AEP_P1-2_#10336-B	operation	167.0	110.85	120.79	DC	16.6
95878208	242613	05COLLEEN SS	138.0	AEP	242603	05CLIFFR	138.0	AEP	1	AEP_P1-2_#10336-B	operation	167.0	107.27	118.54	DC	18.82
98089724	313707	6FORK UNION	230.0	DVP	961060	AF2-397 TAP	230.0	DVP	1	DVP_P1-2: LN 2027-B	operation	661.760009766	141.43	142.49	DC	6.95
98089699	314765	6MTEAGLE	230.0	DVP	314749	6CHARLV L	230.0	DVP	1	DVP_P1-2: LN 2027-B	operation	661.760009766	135.87	136.92	DC	6.95
97456896	938820	AE1-108 TAP	138.0	DVP	314746	4BREMO	138.0	DVP	1	AEP_SUBT_P1 - 3_#231_05CLIFFR 138_1	operation	156.979995728	141.55	154.29	DC	20.0
97456897	938820	AE1-108 TAP	138.0	DVP	314746	4BREMO	138.0	DVP	1	AEP_P1-2_#5400	operation	156.979995728	141.55	154.29	DC	20.0
97456901	938820	AE1-108 TAP	138.0	DVP	314746	4BREMO	138.0	DVP	1	Base Case	operation	156.979995728	104.16	112.13	DC	12.5
97457011	941010	AE2-092 TAP	115.0	DVP	314774	3SHERWOD	115.0	DVP	1	DVP_P1-2: LN 2028-A	operation	169.199996948	115.81	117.1	DC	2.18
95878200	946590	AF1-323 TAP	138.0	AEP	242613	05COLLEEN SS	138.0	AEP	1	AEP_P1-2_#10336-B	operation	167.0	109.49	120.75	DC	18.82

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CK T ID	CONT NAME	Type	Rating MVA	PRE PROJE CT LOADI NG %	POST PROJE CT LOADI NG %	AC D C	MW IMPA CT
980896 53	9610 60	AF2-397 TAP	230. 0	DVP	3147 65	6MTEAG LE	230. 0	DVP	1	DVP_P1-2: LN 2027-B	operati on	661.760009 766	140.03	141.09	DC	6.95

10.5 System Reinforcements

None

10.6 Flow Gate Details

The following indices contain additional information about each facility presented in the body of the report. For each index, a description of the flowgate and its contingency was included for convenience. The intent of the indices is to provide more details on which projects/generators have contributions to the flowgate in question. All New Service Queue Requests, through the end of the Queue under study, that are contributors to a flowgate will be listed in the indices. Please note that there may be contributors that are subsequently queued after the queue under study that are not listed in the indices. Although this information is not used "as is" for cost allocation purposes, it can be used to gage the impact of other projects/generators. It should be noted the project/generator MW contributions presented in the body of the report are Full MW Impact contributions which are also noted in the indices column named "Full MW Impact", whereas the loading percentages reported in the body of the report, take into consideration the PJM Generator Deliverability Test rules such as commercial probability of each project as well as the ramping impact of "Adder" contributions. The MW Impact found and used in the analysis is shown in the indices column named "Gendeliv MW Impact".

10.7 Queue Dependencies

The Queue Projects below are listed in one or more indices for the overloads identified in your report. These projects contribute to the loading of the overloaded facilities identified in your report. The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of these earlier projects. The status of each project at the time of the analysis is presented in the table. This list may change as earlier projects withdraw or modify their requests.

None

10.8 Contingency Descriptions

Contingency Name	Contingency Definition
AEP_P1-2_#10336-B	CONTINGENCY 'AEP_P1-2_#10336-B' OPEN BRANCH FROM BUS 938820 TO BUS 314746 CKT 1 / 938820 AE1-108 TAP 138 314746 4BREMO 138 1 OPEN BRANCH FROM BUS 242792 TO BUS 243803 CKT 3 / 242792 05SCOTSV 138 243803 05SCOTTVIL 46.0 3 END
AEP_SUBT_P1-3_#231_05CLIFFR 138_1	CONTINGENCY 'AEP_SUBT_P1-3_#231_05CLIFFR 138_1' OPEN BRANCH FROM BUS 242500 TO BUS 242603 CKT 1 / 242500 05CLIFRDEQ 999 242603 05CLIFFR 138 1 OPEN BRANCH FROM BUS 242500 TO BUS 242867 CKT 1 / 242500 05CLIFRDEQ 999 242867 05CLIFFORD 69.0 1 OPEN BRANCH FROM BUS 242500 TO BUS 242888 CKT 1 / 242500 05CLIFRDEQ 999 242888 05CLIFFORD 46.0 1 OPEN BRANCH FROM BUS 242563 TO BUS 242603 CKT 1 / 242563 05BOXWD 138 242603 05CLIFFR 138 1 OPEN BRANCH FROM BUS 242563 TO BUS 242765 CKT 1 / 242563 05BOXWD 138 242765 05REUSEN 138 1 OPEN BRANCH FROM BUS 242563 TO BUS 242772 CKT 1 / 242563 05BOXWD 138 242772 05RIVERV 138 1 REMOVE SWSHUNT FROM BUS 242772 / 242772 05RIVERV 138 OPEN BRANCH FROM BUS 242862 TO BUS 242867 CKT 1 / 242862 05AMHERST 69.0 242867 05CLIFFORD 69.0 1 END
AEP_P1-2_#5400	CONTINGENCY 'AEP_P1-2_#5400' OPEN BRANCH FROM BUS 242500 TO BUS 242603 CKT 1 / 242500 05CLIFRDEQ 999 242603 05CLIFFR 138 1 OPEN BRANCH FROM BUS 242500 TO BUS 242867 CKT 1 / 242500 05CLIFRDEQ 999 242867 05CLIFFORD 69.0 1 OPEN BRANCH FROM BUS 242500 TO BUS 242888 CKT 1 / 242500 05CLIFRDEQ 999 242888 05CLIFFORD 46.0 1 OPEN BRANCH FROM BUS 242563 TO BUS 242603 CKT 1 / 242563 05BOXWD 138 242603 05CLIFFR 138 1 OPEN BRANCH FROM BUS 242563 TO BUS 242765 CKT 1 / 242563 05BOXWD 138 242765 05REUSEN 138 1 OPEN BRANCH FROM BUS 242563 TO BUS 242772 CKT 1 / 242563 05BOXWD 138 242772 05RIVERV 138 1 REMOVE SWSHUNT FROM BUS 242603 / 242603 05CLIFFR 138 REMOVE SWSHUNT FROM BUS 242772 / 242772 05RIVERV 138 END

Contingency Name	Contingency Definition
DVP_P1-2: LN 2027-B	CONTINGENCY 'DVP_P1-2: LN 2027-B' OPEN BRANCH FROM BUS 933500 TO BUS 314333 CKT 1 /* AC2-165 TAP 230.00 - 6POWHATN 230.00 OPEN BRANCH FROM BUS 314310 TO BUS 314322 CKT 1 /* 6JUDES F 230.00 - 6MDLTHAN 230.00 OPEN BRANCH FROM BUS 314310 TO BUS 314333 CKT 1 /* 6JUDES F 230.00 - 6POWHATN 230.00 OPEN BUS 314310 /* ISLAND: 6JUDES F 230.00 OPEN BUS 314333 /* ISLAND: 6POWHATN 230.00 OPEN BUS 923862 /* ISLAND: AB2-026 E 230.00 END
DVP_P1-2: LN 2028-A	CONTINGENCY 'DVP_P1-2: LN 2028-A' OPEN BRANCH FROM BUS 961060 TO BUS 314765 CKT 1 /* AF2-397 TAP 230.00 - 6MTEAGLE 230.00 OPEN BRANCH FROM BUS 314749 TO BUS 314765 CKT 1 /* 6CHARLVL 230.00 - 6MTEAGLE 230.00 OPEN BUS 314765 /* ISLAND: 6MTEAGLE 230.00 OPEN BUS 926451 /* ISLAND: AC1-116 C 230.00 OPEN BUS 926452 /* ISLAND: AC1-116 E 230.00 END
Base Case	

11 Light Load Analysis

Light Load Studies (As applicable).

Not applicable

12 Short Circuit Analysis

The following Breakers are overdutied

To be determined during later study phases.

13 Stability and Reactive Power Assessment

(Summary of the VAR requirements based upon the results of the dynamic studies)

To be determined during later study phases.

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).