Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AB1-056

"Indian River 230 kV I"

September 2016

Preface

The intent of the System Impact Study is to determine a plan, with approximate cost and construction time estimates, to connect the subject generation interconnection project to the PJM network at a location specified by the Interconnection Customer. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system. All facilities required for interconnection of a generation interconnection project must be designed to meet the technical specifications (on PJM web site) for the appropriate transmission owner.

In some instances an Interconnection Customer may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection or merchant transmission upgrade, 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 System Impact Study is performed.

The System Impact Study estimates do not include the feasibility, cost, or time required to obtain property rights and permits for construction of the required facilities. The Interconnection Customer 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

US Wind, Inc., the Interconnection Customer (IC), has proposed a 247.8 MW MFO (64.4 MWC) off-shore wind generating facility to be located in the Atlantic Ocean approximately 14 miles off the coast of Ocean City, Maryland. The generating facility will consist of 62 off-shore 4 MW wind turbines. PJM studied AB1-056 as a 247.8 MW injection into the Delmarva Power and Light Company's (DPL) system and evaluated it for compliance with reliability criteria for summer peak conditions in 2019. Project AB1-056 was studied with a commercial probability of 100%. The planned in-service date, as stated during the kick-off call, is March 1, 2020.

Point of Interconnection

AB1-056 will interconnect with the Delmarva Power and Light transmission system at the Indian River 230 kV North Substation at a 230 kV terminal off an existing 230 kV breaker and a half leg within the Substation (see Attachment 1).

Transmission Owner (TO) Scope of Work

Substation Interconnection Estimate

Scope: Build a new 230 kV line terminal at the Indian River 230 kV North Substation. The new terminal will be designed and constructed off an existing breaker and a half leg with Indian River AT22. The project will encompass the design and construction required to add the new 230 kV terminal. DPL has included the scope of work up to the 230 kV take-off structure located just inside

the fence line of DPL’s Indian River 230 kV North Substation. (PJM Network Upgrade Number n5115)
Estimate: $1,356,861
Construction Time: 24 months

Major Equipment Included in Estimate:

• Power Circuit Breaker, 230 kV, 3000A, 40kA, 3 cycle	Qty. 1
• Disconnect Switch, 230 kV, 3000A, Manual Wormgear, Arcing Horns	Qty. 4
• CT/VT Combination Units, 230 kV	Qty. 3
• Disconnect Switch Stand, High, 230 kV, Steel	Qty. 2
• CT/VT Stand, Single-Phase, Low, 230 kV, Steel	Qty. 3
• Relay Panel, Transmission Line, FL/BU (20”)	Qty. 2
• Control Panel, 230 kV Circuit Breaker (20”)	Qty. 1
• Take-off structure, 230 kV	Qty. 1
• Bus Support Structure, 3 phase, 230 kV, Steel	Qty. 1

Estimate Assumptions:

- Substation expansion is not required
- Additional reinforcements of the substation ground grid not required
- Site work including additional site stoning and storm water management is not required
- Lightning protection reinforcements are not required

Required Relaying and Communications

New protection relays are required for the new terminal. An SEL-487 will be required for primary protection and an SEL-387 will be required for back-up protection. Two 20” relay panels will be required for front line and back-up protection.

An SEL-451 relay on a 20” breaker control panel will be required for the control and operation of the new 230 kV circuit breaker.

The project will require re-wiring of existing relay schemes to accommodate the new 230 kV terminal position.
The cost of the required relay and communications is included in the Substation Interconnection Estimate.

Metering

Three phase 230 kV revenue metering points will need to be established. DPL will purchase and install all metering instrument transformers as well as construct a metering structure. The secondary wiring connections at the instrument transformers will be completed by DPL’s metering technicians. The metering control cable and meter cabinets will be supplied and installed by DPL. DPL will install conduit for the control cable between the instrument transformers and the metering enclosure. The location of the metering enclosure will be determined in the construction phase. DPL will provide both the Primary and the Backup meters. DPL’s meter technicians will program and install the Primary & Backup solid state multi-function meters for each new metering position. Each meter will be equipped with load profile, telemetry, and DNP outputs. The IC will be provided with one meter DNP output for each meter. DPL will own the metering equipment for the interconnection point, unless the IC asserts its right to install, own, and operate the metering system.

The Interconnection Customer will be required to make provisions for a voice quality phone line within approximately 3 feet of each Company metering position to facilitate remote interrogation and data collection.

It is the IC's responsibility to send the data that PJM and DPL requires directly to PJM. The IC will grant permission for PJM to send DPL the following telemetry that the IC sends to PJM: real time MW, MVAR, volts, amperes, generator status, and interval MWH and MVARH.
The estimate for DPL to design, purchase, and install metering as specified in the aforementioned scope is included in the Substation Interconnection Estimate.

Interconnection Customer Scope of Work

The Interconnection Customer is responsible for all design and construction related to activities on their side of the Point of Interconnection. Site preparation, including grading and an access road, as necessary, is assumed to be by the IC. Route selection, line design, and right-of-way acquisition of the direct connect facilities is not included in this report, and is the responsibility of the IC. Protective relaying and metering design and installation must comply with DPL's applicable standards. The IC is also required to provide revenue metering and real-time telemetering data to PJM in conformance with the requirements contained in PJM Manuals M-01 and M-14 and the PJM Tariff.

DPL Interconnection Customer Scope of Direct Connection Work Requirements:

- DPL requires that an IC circuit breaker is located within 500 feet of the DPL substation to facilitate the relay protection scheme between DPL and the IC at the Point of Interconnection (POI).

Special Operating Requirements

1. DPL will require the capability to remotely disconnect the generator from the grid by communication from its System Operations facility. Such disconnection may be facilitated by a generator breaker, or other method depending upon the specific circumstances and the evaluation by DPL.

2. DPL reserves the right to charge the Interconnection Customer operation and maintenance expenses to maintain the Interconnection Customer attachment facilities, including metering and telecommunications facilities, owned by DPL.

Additional Interconnection Customer Responsibilities:

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.

3. The Interconnection Customer seeking to interconnect a wind generation facility shall maintain meteorological data facilities as well as provide that meteorological data which is required per item 5.IV of Schedule H to the Interconnection Service Agreement.

Summer Peak Analysis - 2019

Transmission Network Impacts

Potential transmission network impacts are as follows:

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

Summer Peak Load Flow Analysis Reinforcements

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)

None

Steady-State Voltage Requirements

No issues identified.

Short Circuit

No issues identified.

Stability and Reactive Power Requirement

No problems identified. See Attachment 2 for full report.

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.

1. (PECO - PECO) The LINWOOD-CHICHST1 230 kV line (from bus 213750 to bus 213489 ckt 1) loads from 100.72% to 103.05% (DC power flow) of its emergency rating (1593 MVA) for the single line contingency outage of '220-39'. This project contributes approximately 43.65 MW to the thermal violation.

   CONTINGENCY '220-39'/* $ DELCO $ 220-39 $ L
   TRIP BRANCH FROM BUS 213490 TO BUS 213750 CKT 1/*
   END

2. (PECO - PECO) The LINWOOD-CHICHST2 230 kV line (from bus 213750 to bus 213490 ckt 1) loads from 100.58% to 102.9% (DC power flow) of its emergency rating (1593 MVA) for the single line contingency outage of '220-43/* $ DELCO $ 220-43 $ L'. This project contributes approximately 43.59 MW to the thermal violation.

   CONTINGENCY '220-43/* $ DELCO $ 220-43 $ L'
   TRIP BRANCH FROM BUS 213489 TO BUS 213750 CKT 1/*
   END/*$ DELCO $ 220-43 $ L

Light Load Analysis - 2019

Light Load Studies to be conducted during later study phases (as required by PJM Manual 14B).

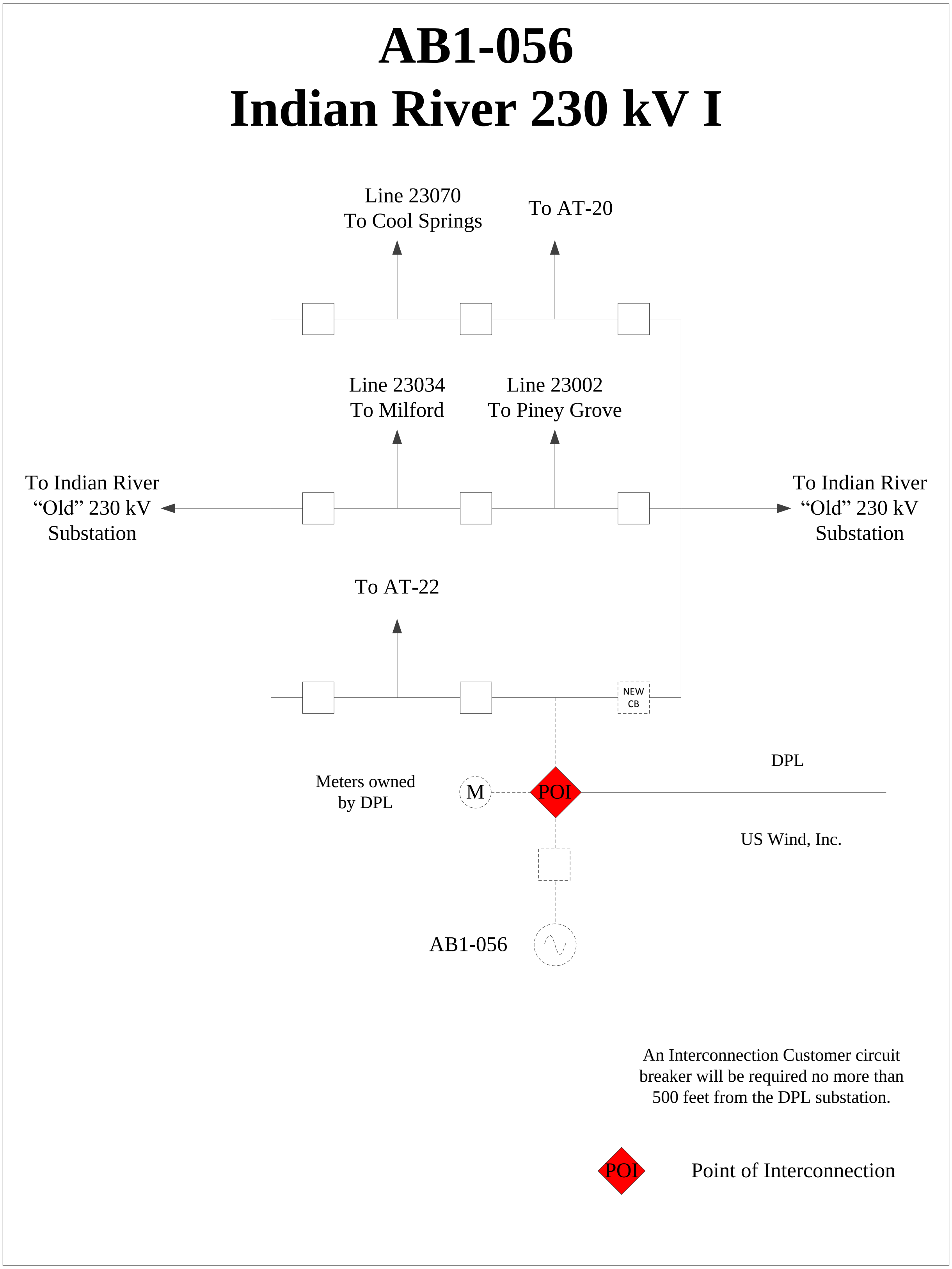
Facilities Study Estimate

The estimated time for PJM to issue a Facilities Study Report is 7 months. The deposit required for the AB1-056 project will be $100,000.

Delmarva Power and Light Costs

Cost estimates will further be refined as a part of the Facilities Study for this project. The Interconnection Customer will be responsible for all costs incurred by DPL in connection with the AB1-056 project. Such costs may include, but are not limited to, any transmission system assets currently in DPL's rate base that are prematurely retired due to the AB1-056 project. PJM shall work with DPL to identify these retirement costs and any additional expenses. DPL reserves the right to reassess issues presented in this document and, upon appropriate justification, submit additional costs related to the AB1-056 project.

Attachment 1



Attachment 2

AB1-056

System Impact Study

Dynamic Simulation Analysis

Table of Contents

Executive Summary

Generator Interconnection Request AB1-056 is for a 247.8 MW Maximum Facility Output (MFO) offshore wind generation facility. AB1-056 consists of 41 GE Haliade-150 6.0 MW wind turbines with a Point of Interconnection (POI) at the Indian River 230 kV Substation in the DPL transmission system.

This report describes a dynamic simulation analysis of AB1-056 as part of the overall system impact study.

The load flow scenario for the analysis was based on the RTEP 2019 Summer Peak cases, modified to include applicable queue projects. AB1-056 was dispatched online at maximum power output and unity power factor at the generator bus.

AB1-056 was tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. 78 contingencies were studied, each with a 20 second simulation time period. Studied faults included:

a) Steady state operation (20 second simulation);
b) Three phase faults with normal clearing time;
c) Single phase faults with stuck breaker;
d) Single-phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from the fault due to primary communications/relay failure.

For all simulations, the queue project under study along with the rest of the PJM system were required to maintain synchronism and with all states returning to an acceptable new condition following the disturbance.

All fault contingencies tested on the 2019 light load and summer peak cases met the recovery criteria:

a) AB1-056 was able to ride through the faults (except for faults where protective action tripped a generator(s)),
b) Post-contingency oscillations were positively damped with a damping margin of at least 3%
c) Following fault clearing, all bus voltages recovered to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).
d) No transmission element tripped, other than those either directly connected or designed to trip as a consequence of that fault.

No mitigations were found to be required.

1. Introduction

Generator Interconnection Request AB1-056 is for a 247.8 MW Maximum Facility Output (MFO) offshore wind generation facility. AB1-056 consists of 41 GE Haliade-150 6.0 MW wind turbines with a Point of Interconnection (POI) at the Indian River 230 kV Substation in the DPL transmission system.

This analysis is effectively a screening study to determine whether the addition of AB1-056 will meet the dynamic requirements of the NERC, PJM and Transmission Owner reliability standards.
In this report the AB1-056 project and how it is proposed to be connected to the grid are first described, followed by a description of how the project is modeled in this study. The fault cases are then described and analyzed, and lastly a discussion of the results is provided.

2. Description of Project

AB1-056 consists of 41 GE Haliade-150 6.0 MW wind turbines and 41 34.5/0.84 kV GSU transformers. AB1-056 will be connected to the POI via a 230/34.5 kV 168/224/280 MVA main collector transformer and 33.4 mile undersea transmission cable. AB1-056 will be directly connected to the Indian River 230 kV Substation in the DPL transmission system as shown in Figure 1.
Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AB1-056 loadflow model.

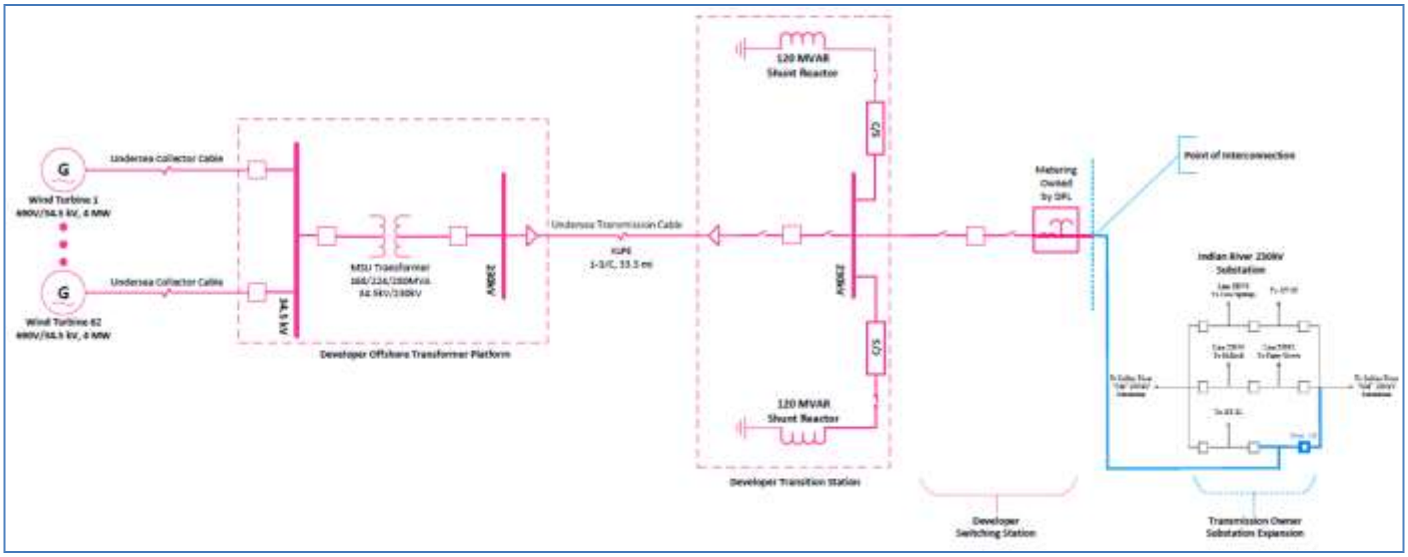


Figure 1: AB1-056 Plant Model

Table 1: AB1-056 Plant Model

	Impact Study Data	Model
GE Haliade-150 wind turbine generators	41 x GE Haliade-150 6.0 MW wind turbine generators MVA base = 246 MVA Vt = 0.84 kV Unsaturated sub-transient reactance = j0.7162 pu @ MVA base	Lumped equivalent representing 41 x GE Haliade-150 6.0 MW wind turbine generators Pgen 246.0 MW Pmax 246.0 MW Pmin 22.5 MW Qgen -15.3 MVAr Qmax 0.0 MVAr Qmin -0.0 MVAr Mbase 246.0 MVA Zsorce j0.7162 pu @ Mbase
Reactors	2 x 120 MVAr shunt reactors	2 x 120 MVAr shunt reactors at the 230 kV bus (switched off)
GE Haliade-150 wind turbine GSU transformers	41 x 34.5/0.84 kV transformers Rating = 6.8 MVA (OA) Transformer base = 6.8 MVA Impedance = 0.011 + j0.0944 @ MVA Base	Lumped equivalent representing 41 x GE Haliade-150 x 6.8 MVA GSU transformers Rating = 278.8 MVA Transformer base = 278.8 MVA Impedance = 0.011 + j0.0944 @ MVA Base
Collector transformer	1 x 230.0/34.5/13.8 kV three winding transformer Rating = 168/224/280 MVA (OA/F1/F2) Transformer base = 168 MVA Impedances High to low: 0.0035 + j0.1553 All impedances are @ MVA Base	1 x 230.0/34.5/13.8 kV three winding transformer Rating = 168/224/280 MVA (OA/F1/F2) Transformer base = 168 MVA Impedances High to low: : 0.0035 + j0.1553 pu All impedances are @ MVA Base
Auxiliary load	N/A	Not modeled
Station load	N/A	Not modeled
Undersea Transmission cable	Length = 33.4 miles Impedance = 0.00579 + j0.01443 pu B= 2.0364	Length = 33.4 miles Impedance = 0.00579 + j0.01443 pu B= 2.0364
Collector System Equivalent	Req = 0.004383 pu Xeq = 0.005762 pu Beq = 0.077316 pu	Req = 0.004383 pu Xeq = 0.005762 pu Beq = 0.077316 pu

3. Loadflow and Dynamics Case Setup

The dynamics simulation analysis was carried out using PSS/E Version 32.2.4.
The load flow scenario and fault cases for this study are based on PJM's Regional Transmission Planning Process[1].
The selected load flow scenarios are the RTEP 2019 summer peak case and light load case with the following modifications:

a) Addition of all applicable queue projects prior to AB1-056.

b) Addition of AB1-056 queue project.

c) Dispatch of units in the PJM system in order to maintain slack generators within limits.

The AB1-056 initial conditions are listed in Table 2, indicating maximum power output, with unity power factor.

Table 2: AB1-056 machine initial conditions

Load flow case	Bus	Name	Unit	PGEN	QGEN	ETERM	POI Voltage
SP	930204	AB1-056 GEN	1	246 MW	0 MVAr	1.0155 pu	1.0217 pu

Generation within the PJM500 system (area 225 in the PSS/E case) and within the vicinity of AB1-056 has been dispatched online at maximum output (PMAX).

4. Fault Cases

Tables 3 to 7 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over a 20 second simulation time interval. The studied contingencies include:

a) Steady state operation (20 second simulation);

b) Three phase faults with normal clearing time;

c) Single phase faults with stuck breaker;

d) Single-phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from the fault due to primary communications/relay failure.

No relevant bus or high speed recloser contingencies were identified for this study.
The contingencies listed above were applied to:

- Indian River 230 kV (POI)
- Cool Spring 230 kV
- Milford 230 kV

[1] Manual 14B: PJM Region Transmission Planning Process, Rev 33, May 5 2016, Attachment G: PJM Stability, Short Circuit, and Special RTEP Practices and Procedures.

- Suffolk 230 kV
- Indian River 138 kV

The three phase faults with normal clearing time were performed under network intact conditions. Additional delayed (Zone 2) clearing at remote end faults were applied on lines.
The positive sequence fault impedances for single line to ground faults were derived from a separate short circuit case, modified to ensure that connected generators in the vicinity of AB1-056 have not withdrawn from the PJM queue, and are not greater than the queue position under study.

5. Evaluation Criteria

This study is focused on AB1-056, along with the rest of the PJM system, maintaining synchronism and having all states return to an acceptable new condition following the disturbance. The recovery criteria applicable to this study are as per PJM's Regional Transmission Planning Process and Transmission Owner criteria:

a) AB1-056 is able to ride through the faults (except for faults where protective action trips AB1-056),
b) The system with AB1-056 included is transiently stable and post-contingency oscillations should be positively damped with a damping margin of at least 3%.
c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).
d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

6. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6, with results summarized in Table 3 through Table 6.

All fault contingencies tested on the 2019 light load and summer peak cases met the recovery criteria:

a) AB1-056 was able to ride through the faults (except for faults where protective action tripped a generator(s))

b) Post-contingency oscillations were positively damped with a damping margin of at least 3%

c) Following fault clearing, all bus voltages recovered to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus)

d) No transmission element tripped, other than those either directly connected or designed to trip as a consequence of that fault

The results show overshoot in the Pelec output greater than Pmax for several contingencies. The spikes did not seem to cause other issues (e.g. units to trip etc.) therefore we do not believe mitigation is required.

No mitigations were found to be required for AB1-056 project.

Table 3: Steady State Operation

Fault ID	Duration
SS.01	Steady State 20 sec run

Table 4: Three-phase Faults With Normal Clearing

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Results
3N.00	3ph fault on AB1-056 Main – AB1-056 Reactor 230 kV line (Undersea transmission cable fault and trips AB1-056)	7	Stable
3N.01	3ph fault on Indian River – Piney Grove 230 kV line	7	Stable
3N.02	3ph fault on Indian River – Milford 230 kV line	7	Stable
3N.03	3ph fault on Indian River – Cool Spring 230 kV line	7	Stable
3N.04	3ph fault on Indian River 230/138 kV transformer #1	7	Stable
3N.05	3ph fault on Indian River 230/138 kV transformer #2	7	Stable
3N.06	3ph fault on Indian River 230/138 kV transformer #3	7	Stable
3N.07	3ph fault on Indian River T4 GSU (Trips IR4 gen)	7	Stable
3N.08	3ph fault on Indian River T5 SVC	7	Stable
3N.09	3ph fault on Cool Spring – Milford 230 kV line	7	Stable
3N.10	3ph fault on Cool Spring 230/69 kV transformer	7	Stable
3N.11	3ph fault on Milford – Cedar Creek 230kV line	7	Stable
3N.12	3ph fault on Milford – Steele 230 kV line	7	Stable
3N.13	3ph fault on Milford – Magnolia (Cartanza) 230 kV line	7	Stable
3N.14	3ph fault on Milford – 230/138 kV transformer	7	Stable
3N.15	3ph fault on Piney Grove 230/138 kV transformer	7	Stable
3N.16	3ph fault on Indian River – Bishop 138 kV line	9	Stable
3N.17	3ph fault on Indian River – Nelson 138 kV line	9	Stable
3N.18	3ph fault on Indian River – Frankford – Bishop 138 kV line	9	Stable
3N.19	3ph fault on Indian River – Omar – Roxana 138 kV line	9	Stable
3N.20	3ph fault on Indian River – Robinsonville 138 kV line	9	Stable
3N.21	3ph fault on Indian River – Conaway 138 kV line	9	Stable
3N.22	3ph fault on Indian River 138/69 kV transformer	9	Stable

Table 5: Single-phase Faults with Stuck Breaker

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Results
1B.01	SLG fault on Indian River – Cool Spring 230kV line, SB 237 @Indian River, loss of nothing	7/17.5	Stable
1B.02	SLG fault on Indian River – Cool Spring 230kV line, SB 238 @Indian River, loss of Indian River 230/138kV #1 TX	7/17.5	Stable
1B.03	SLG fault on Indian River 230/138kV #1 TX, SB 239 @Indian River, loss of Indian River 230kV capbank	7/17.5	Stable

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Results
1B.04	SLG fault on Indian River – Piney Grove 230kV, SB 234 @Indian River, loss of Indian River 230kV capbank	7/17.5	Stable
1B.05	SLG fault on Indian River – Piney Grove 230kV, SB 235 @Indian River, loss of Indian River – Milford 230kV line	7/17.5	Stable
1B.06	SLG fault on Indian River – Milford 230kV, SB 236 @Indian River, loss of nothing	7/17.5	Stable
1B.07	SLG fault on Indian River 230/138kV #3 TX, SB 241 @Indian River, loss of Indian River 230kV capbank	7/17.5	Stable
1B.08	SLG fault on Indian River 230/138kV #3 TX, SB 242 @Indian River, loss of nothing	7/17.5	Stable
1B.09	SLG fault on Indian River SVC T5 230kV, SB 232 @Indian River, loss of Indian River 230kV capbank	7/17.5	Stable
1B.10	SLG fault on Indian River SVC T5 230kV, SB 9440 @Indian River, loss of nothing	7/17.5	Stable
1B.11	SLG fault on Indian River Gen 4 T4 230kV, SB 9470 @Indian River, loss of nothing	7/17.5	Stable
1B.12	SLG fault on Indian River Gen 4 T4 230kV, SB 233 @Indian River, loss of Indian River 230/138kV #2 TX	7/17.5	Stable
1B.13	SLG fault on Indian River 230/138kV #2 TX, SB 9460 @Indian River, loss of Indian River 230kV capbank	7/17.5	Stable
1B.14	SLG fault on Piney Grove 230/138kV TX, SB 9530@Piney Grove, loss of Piney Grove – Indian River 230kV line	7/17.5	Stable
1B.15	SLG fault on Milford – Cool Spring 230kV, SB 231 @Milford, loss of Milford – Magnolia (Cartanza) 230kV line	7/17.5	Stable
1B.16	SLG fault on Milford – Cool Spring 230kV, SB 9390 @Milford, loss of Milford 230/138kV TX.	7/17.5	Stable
1B.17	SLG fault on Milford 230/138kV TX, SB 9380 @Milford, loss of Milford – Cedar Creek 230kV	7/17.5	Stable
1B.18	SLG fault on Milford – Cedar Creek 230kV, SB 232 @Milford, loss of Milford – Indian River 230kV	7/17.5	Stable
1B.19	SLG fault on Milford – Steele 230kV, SB 9310 @Milford, loss of Milford – Indian River 230kV	7/17.5	Stable
1B.20	SLG fault on Milford – Steele 230kV, SB 9320 @Milford, loss of Milford – Magnolia (Cartanza) 230kV line	7/17.5	Stable
1B.21	SLG fault on Cool Spring – Milford 230kV, SB 230 @Cool Spring, loss of Cool Spring – Indian River 230kV	7/17.5	Stable
1B.22	SLG fault on Cool Spring – Milford 230kV, SB 231 @Cool Spring, loss of Cool Spring 230/69kV TX	7/17.5	Stable
1B.23	SLG fault on Cool Spring 230/69kV TX, SB 232 @Cool Spring, loss of Cool Spring – Indian River 230kV	7/17.5	Stable
1B.24	SLG fault on Indian River – Conaway 138kV line, SB 8080@Indian River, loss of nothing	9/21	Stable

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Results
1B.25	SLG fault on Indian River – Conaway 138kV line, SB 8090@Indian River, loss of Indian River 138/14.4kV T2	9/21	Stable
1B.26	SLG fault on Indian River 138/14.4kV T2, SB 8100@Indian River, loss of nothing	9/21	Stable
1B.27	SLG fault on Indian River 138/230kV #3 TX, SB 134@Indian River, loss of nothing	9/21	Stable
1B.28	SLG fault on Indian River 138/230kV #3 TX, SB 135@Indian River, loss of Indian River – Bishop 138kV line	9/21	Stable
1B.29	SLG fault on Indian River – Bishop 138kV line, SB 136@Indian River, loss of nothing	9/21	Stable
1B.30	SLG fault on Indian River – Nelson 138kV line, SB 8070@Indian River, loss of nothing	9/21	Stable
1B.31	SLG fault on Indian River – Nelson 138kV line, SB 8060@Indian River, loss of Indian River – Robinsonville 138kV line	9/21	Stable
1B.32	SLG fault on Indian River – Robinsonville 138kV line, SB 130@Indian River, loss of nothing	9/21	Stable
1B.33	SLG fault on Indian River – Frankford – Bishop 138kV, SB 8050@Indian River, loss of nothing	9/21	Stable
1B.34	SLG fault on Indian River – Frankford – Bishop 138kV, SB 8040@Indian River, loss of Indian River 138/20kV T3	9/21	Stable
1B.35	SLG fault on Indian River 138/20kV T3, SB 8030@Indian River, loss of nothing	9/21	Stable
1B.36	SLG fault on Indian River 138/69kV TX, SB 133@Indian River, loss of nothing	9/21	Stable
1B.37	SLG fault on Indian River 138/69 TX, SB 132@Indian River, loss of 138/230kV #1 TX	9/21	Stable
1B.38	SLG fault on Indian River 138/230kV #1 TX, SB 131@Indian River, loss of nothing	9/21	Stable
1B.39	SLG fault on Indian River – Omar – Roxana 138kV line, SB 8000@Indian River, loss of nothing	9/21	Stable
1B.40	SLG fault on Indian River – Omar – Roxana 138kV line, SB 8010 @Indian River, loss of Indian River 138/230kV #2 TX	9/21	Stable
1B.41	SLG fault on Indian River 138/230kV #2 TX, SB 8020 @ Indian River, loss of nothing	9/21	Stable

Table 6: Single-phase Faults With Delayed (Zone 2) Clearing at line end nearest to AB1-056

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Results
1D.01	SLG fault of Indian River – Piney Grove 230 kV line	7/25	Stable
1D.02	SLG fault of Indian River – Milford 230 kV line	7/25	Stable
1D.03	SLG fault of Indian River – Cool Spring 230 kV line	7/25	Stable
1D.04	SLG fault of Cool Spring – Milford 230 kV line	7/25	Stable
1D.05	SLG fault of Milford – Cool Spring 230 kV line	7/25	Stable
1D.06	SLG fault of Milford – Cedar Creek 230 kV line	7/25	Stable
1D.07	SLG fault of Milford – Steele 230 kV line	7/25	Stable
1D.08	SLG fault of Milford – Magnolia (Cartanza) 230 kV line	7/25	Stable
1D.09	SLG fault of Indian River – Bishop 138kV line	9/37	Stable
1D.10	SLG fault of Indian River – Nelson 138kV line	9/37	Stable
1D.11	SLG fault of Indian River – Frankford - Bishop 138kV line	9/37	Stable
1D.12	SLG fault of Indian River – Omar – Roxana 138kV line	9/37	Stable
1D.13	SLG fault of Indian River – Robinsonville 138kV line	9/37	Stable
1D.14	SLG fault of Indian River – Conaway 138kV line	9/37	Stable