System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AC1-110

Aurora 138kV

February 2020

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: (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. 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 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 or merchant transmission upgrade, may also contribute to the need for the same network reinforcement.

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 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 Queue AC1-110 project is an Aurora Generation, LLC ("Interconnection Customer" or "IC"), a LS Power owned facility, proposal to uprate the existing Aurora Generating Station, located at 2909 North Eola Road, Aurora, Dupage County, IL, 60502.

The AC1-110 project proposes a 30 MW increase in MFO and Capacity for Units 3 and 4.

Unit	Description	PSSE Bus No.	Existing CIRs	CIRs after AC1 Queue
3	GE PG7241FA	274737	152	152+15=167
4	GE PG7241FA	274739	152	152+15=167

These projects are all uprates of existing facilities and no electrical changes to the generators, transformers, etc. are proposed.

The IC has indicated the increased capability is available now.   A backfeed date for this facility is not applicable.

This Generation Interconnection System Impact Study provides analysis results to aid the IC in assessing the practicality and cost of incorporating the facility into the PJM system.

Point of Interconnection

This is an existing facility and there will be no changes to the POI

Attachment Facilities

No new attachment Facilities

Direct Connection Network Upgrades

No new direct connection network upgrades are necessary

Network Impacts

The Queue Project AC1-110 was evaluated as a 30.0 MW (Capacity 30.0 MW) injection into the Aurora EC; BP 138 kV substation in the ComEd area. Project AC1-110 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AC1-110 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Summer Peak Analysis - 2020

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)

Not required

Affected System Analysis & Mitigation

MISO Impacts:

None

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.

Not applicable

Light Load Analysis

Not required

Stability and Reactive Power Requirement

(Results of the dynamic studies should be inserted here)

Generator Interconnection Requests AC1-109, AC1-110 and AC1-111 are for an increase in energy injection capability of the existing natural gas facility Aurora 345 kV station. AC1-109 uprate increases the MFO by 30 MW in total for Aurora units 1 and 2. AC1-110 uprate increases 30 MW of Aurora units 3 and 4. AC1-111 uprate increases 4.3 MW of Aurora units 5, 6, 7, 8, 9 and 10.
This report describes a dynamic simulation analysis of AC1-109/110/111 as part of the overall system impact study.
The load flow scenario for the analysis is based on the RTEP 2020 Light Load case, modified to include applicable queue projects. AC1-109/110/111 projects were set to maximum power output and were tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. Each contingency was studied over a 20 second simulation time interval. The studied contingencies include:

a) Steady state operation;
b) Three phase faults with normal clearing time on intact network and with prior outage of network element;
c) Three-phase faults with single line to ground delayed clearing due to a stuck breaker (for independent pole breakers);
d) Three-phase faults with three-phase delayed clearing due to a stuck breaker (for gang-operated breakers);
e) Three-phase faults with three-phase delayed clearing and single-phase delayed clearing due to a stuck breaker (for gang-operated breakers with a-contact logic);
f) Three 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 (all gang operated breakers);
g) Three phase faults with loss of multi-circuit tower line;
h) Single-phase fault at substation bus

For all simulations, the queue projects 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. For the fault contingencies tested on the 2020 Light Load case:

a) Post-contingency oscillations were positively damped with a damping margin of at least 3% for all contingencies, based on the PELEC channels using a 6 – 19 second timespan.

b) The AC1-109 generator was able to ride through all faults (except for faults where protective action trips a generator(s)).

c) AC1-110 tripped due to angle deviation for the following contingencies:

- 3B3.15/16/17/18/20

d) AC1-111 tripped due to angle deviation for the following contingencies:

- 3B3.10 (only generators 8,9,10 tripped)

e) 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).

PJM determined critical clearing time for 6/19 for 3B3.10 fault and ComEd confirmed the actual total clearing time should be 6/15 therefore 6/19 clearing time is acceptable. PJM determined the critical clearing time of 6/13 for 3B3.15/16/17/18 faults and ComEd confirmed 2-cycle timer adjustment was achievable for the faults under baseline upgrade (b3147). AC1-110 trip due to 3B3.20 contingency is a pre-existing condition. Critical clearing time for 3B3.20 fault pre-uprate is 6/11 cycles, the pre-existing condition requires a timer change which is within the capabilities of the existing equipment under baseline upgrade (b3147). Post-uprate the critical clearing time is 6/9 cycles and the 6/9 clearing time for 3B3.20 fault will require modification of breaker failure scheme to incorporate “A-Contact” logic to 138 kV blue bus to reduce total clearing times at TSS111 Electric Junction to 9 cycles for fault on 345/138 kV transformer 81. The estimated cost of the required relay work is **$140,000** (Network upgrade# **n6285**). The pre-Engineering is not complete and the estimate is an order-of-magnitude estimate.

The required mitigation will be the responsibility of PJM Project #AC1-110.

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

Conclusion

Based upon the results of this System Impact Study, the increase of 30.0 MW (30.0 MW Capacity) to Units 3 and 4 of the Aurora Generating Facility (PJM Project #AC1-110) will require additional interconnection charges.

Figure 1: Point of Interconnection Single Line Diagram