Generator Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position #AA2-070

Smith Mountain 138 kV

February 2018

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 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

American Electric Power Service Corp. (AEPSC) proposes to increase the generation at the Smith Mountain 138 kV Hydro plant by 34 MW (34 MW Capacity) to a total MFO of 649 MW (See Figure 1). PJM Project Queue AA2-070, 34 MW (34 MW Capacity) increase is due to demonstrated testing. In addition, it was noted that the generators for units #2 and #4 were rewound. The location of the generating facility is in Sandy Level, VA (See Figure 2).

The requested in service date is June 1, 2015. Since the requested service date is ahead of the 2019 study year of PJM Project Queue AA2-070, AEPSC has submitted an interim deliverability study request to PJM to determine if deliverability of the generator ahead of its 2019 study year is possible.

Attachment Facilities

Not required for an existing facility

Local and Network Impacts

The impact of the proposed generating facility on the AEP Transmission System was assessed for adherence with applicable reliability criteria. AEP planning criteria require that the transmission system meet performance parameters prescribed in the AEP FERC Form 715[1] and Connection Requirements for AEP Transmission System[2]. Therefore, these criterion were used to assess the impact of the proposed facility on the AEP System. PJM Queue # AA2-070 was studied as a 34 MW (34 MW capacity) injection at Smith Mountain 138 kV station consistent with the interconnection application. Project #AA2-070 was evaluated for compliance with reliability criteria for summer peak conditions in 2019.

Network Impacts

The Queue Project AA2-070 was evaluated as a 34.0 MW (Capacity 34.0 MW) injection into the Smith Mountain 138 kV substation in the AEP area. Project AA2-070 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AA2-070 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Summer Peak Analysis - 2019

1 https://www.aep.com/about/codeofconduct/oasis/transmissionstudies/GuideLines/2014%20AEP%20PJM%20FERC%20715_Final_Part%204.pdf

2 https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/Requirements/AEP_Interconnection_Requirements_rev1.pdf

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

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 - 2019

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

There were no light load thermal violations identified for this project.

Stability Analysis

(See detailed Stability and Reactive Requirements Study at the end of this report)

Plots from the dynamic simulations are provided in Attachment 6 with results summarized in Table 5 to Table 11.
The results indicate that for the 95 of the 97 fault contingencies tested on the RTEP 2019 light load case:

a) The system with AA2-070 included was found to be transiently stable,

b) AA2-070 was able to ride through the faults (except for faults where protective action tripped AA2-070).

The stability criteria were not met for two stuck breaker contingencies (1B.03 and 1B.05) due to unanticipated tripping of units at Smith Mountain. Tests using the pre-uprate model for Smith Mountain showed that the uprate (AA2-070) is responsible for the unanticipated tripping of units during stuck breaker simulations 1B.03 and 1B.05. Additional testing showed that a reduction in the total stuck breaker clearing time from 16.0 cycles to 14.0 cycles mitigates the instability.
The unanticipated tripping and insufficient damping can also be mitigated if the units are operated with the terminal voltages at or above the values shown in Table 5.

Table 1: Minimum required terminal voltages

Generating unit	Terminal Voltage (pu)
Smith Mountain G1	0.98
Smith Mountain G2	0.99
Smith Mountain G3	1.00
Smith Mountain G4	0.99
Smith Mountain G5	0.98

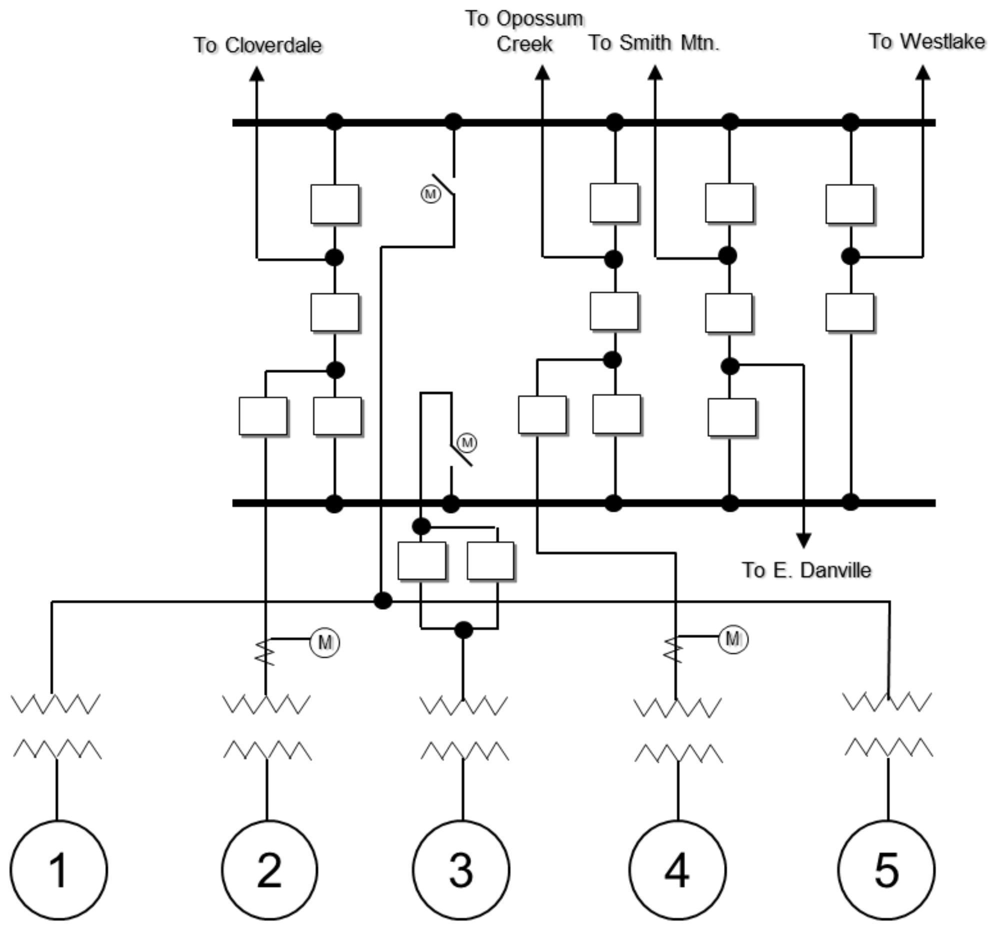
It should be noted that the post fault responses of all Smith Mountain units were underdamped, with modal analysis of the active power response showing damping margins as low as 3.2%. Although the required damping margin was met for all contingencies tested, the addition of power system stabilizers on the Smith Mountain units may improve the damping of post fault oscillations.

Conclusion

Based upon the results of this System Impact Study, the injection of an additional 34 MW (34 MW Capacity) at Mountain Smith 138 kV Hydro Plant would not require additional

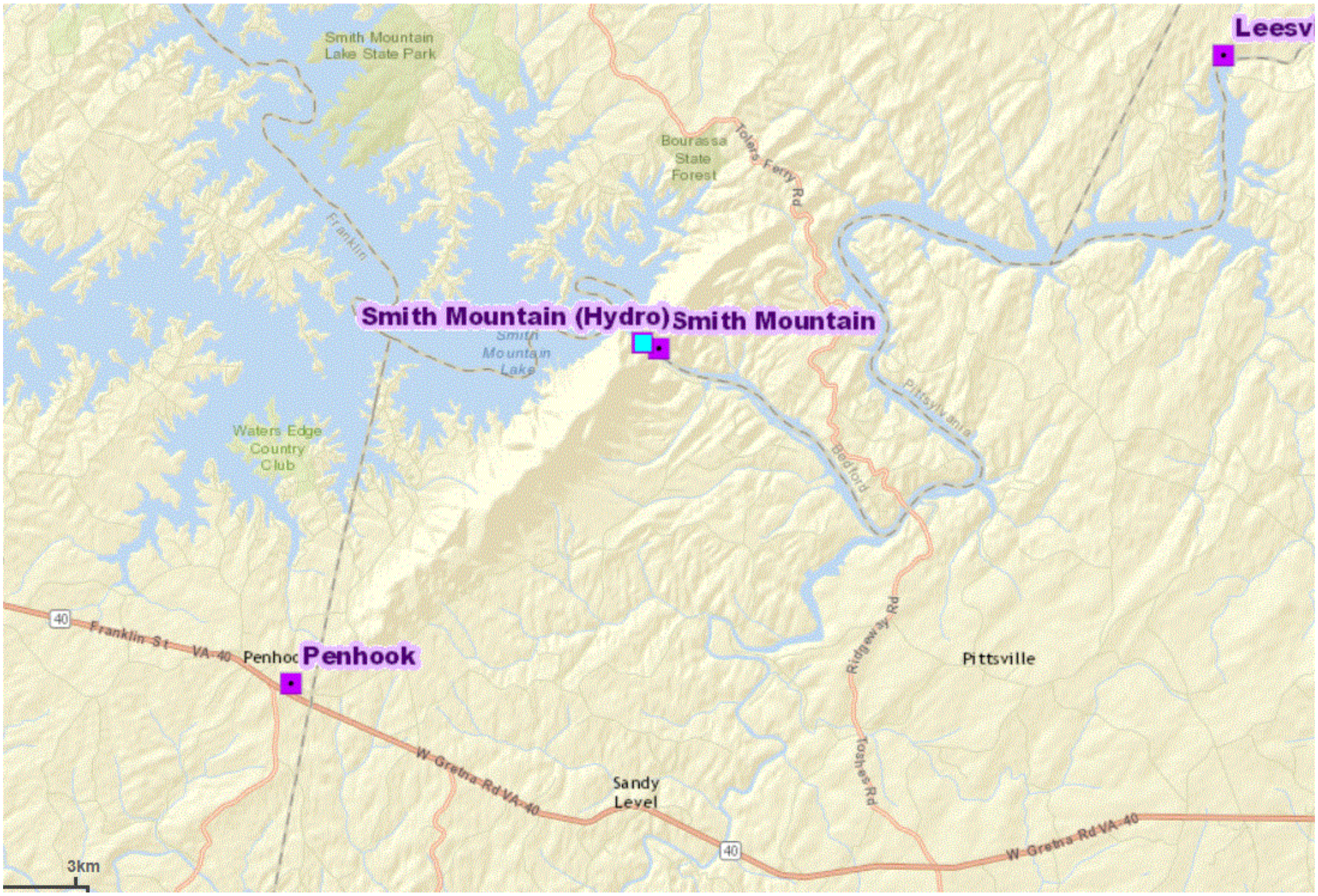
Network upgrades, but will require adherence to a predetermined voltage schedule as noted in the attached stability and reactive power study at the end of this report.

Figure 1: Single-Line Diagram



*Proposed 34 MW Total Increase (Units 2 & 4)

Figure 2: AA2-070 Point of Interconnection



Stability and Reactive Power Requirement

Executive Summary

Generator Interconnection Request AA2-070 is for a 34 MW uprate of the existing pumped storage facility at the Smith Mountain Hydroelectric Plant. The uprate will increase the Maximum Facility Output (MFO) of Smith Mountain Hydroelectric Plant from 615 MW to 649 MW. The AA2-070 Point of Interconnection (POI) is at the Smith Mountain 138 kV Substation in the American Electric Power (AEP) system in Henry County, Virginia.

This report describes a dynamic simulation analysis of AA2-070 as part of the overall system impact study.

The load flow scenario for the analysis was based on the RTEP 2019 light load case, modified to include applicable queue projects. AA2-070 was set to maximum power output, with leading power factor and less than 1.0 pu voltage at the generator terminals.

AA2-070 was tested for compliance with NERC, PJM and other applicable criteria. 97 contingencies were studied, each with a 20 second simulation time period. Studied scenarios included:

a) Steady state operation
b) Three phase faults with normal clearing time
c) Three phase faults with loss of multiple-circuit tower line
d) Single phase faults with single phase stuck breaker
e) Single phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from fault due to primary communications/relaying failure
f) Single-phase bus faults with normal clearing time

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.

The results indicate that for the 95 of the 97 fault contingencies tested on the RTEP 2019 light load case:

a) The system with AA2-070 included was found to be transiently stable,
b) AA2-070 was able to ride through the faults (except for faults where protective action tripped AA2-070).

The stability criteria were not met for two stuck breaker contingencies (1B.03 and 1B.05) due to unanticipated tripping of units at Smith Mountain. Tests using the pre-uprate model for Smith Mountain showed that the uprate (AA2-070) is responsible for the unanticipated tripping of units during stuck breaker simulations 1B.03 and 1B.05. Additional testing showed that a reduction in the total stuck breaker clearing time from 16.0 cycles to 14.0 cycles mitigates the instability.

The unanticipated tripping and insufficient damping can also be mitigated if the units are operated with the terminal voltages at or above the values shown in Table 2.

Table 2: Minimum required terminal voltages

Generating unit	Terminal Voltage (pu)
Smith Mountain G1	0.98
Smith Mountain G2	0.99
Smith Mountain G3	1.00
Smith Mountain G4	0.99
Smith Mountain G5	0.98

1. Introduction

Generator Interconnection Request AA2-070 is for a 34 MW uprate of the existing pumped storage facility at the Smith Mountain Hydroelectric Plant. The uprate will increase the Maximum Facility Output (MFO) of Smith Mountain Hydroelectric Plant from 615 MW to 649 MW. The AA2-070 Point of Interconnection (POI) is at the Smith Mountain 138 kV Substation in the American Electric Power (AEP) system in Henry County, Virginia.

This analysis is effectively a screening study to determine whether the addition of AA2-070 will meet the dynamics requirements of the NERC, PJM and other applicable reliability standards.

In this report the AA2-070 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. <u>Description of Project</u>

Generator Interconnection Request AA2-070 is for a 34 MW uprate of the existing pumped storage facility at the Smith Mountain Hydroelectric Plant. The uprate will increase the Maximum Facility Output (MFO) of Smith Mountain Hydroelectric Plant from 615 MW to 649 MW. The AA2-070 Point of Interconnection (POI) is at the Smith Mountain 138 kV Substation in the American Electric Power (AEP) system in Henry County, Virginia.

Figure 1 shows the simplified one-line diagram of the AA2-070 loadflow model. Table 2 lists the parameters given in the impact study data and the corresponding parameters of the AA2-070 loadflow model.

Additional project details are provided in Attachments 1 through 4:

- Attachment 1 contains the Impact Study Data which details the proposed AA2-070 project.
- Attachment 2 shows the one line diagram of the AEP system in the vicinity of AA2-070.
- Attachment 3 provides a diagram of the PSS/E model in the vicinity of AA2-070.
- Attachment 4 gives the PSS/E loadflow and dynamic models of the AA2-070 plant.

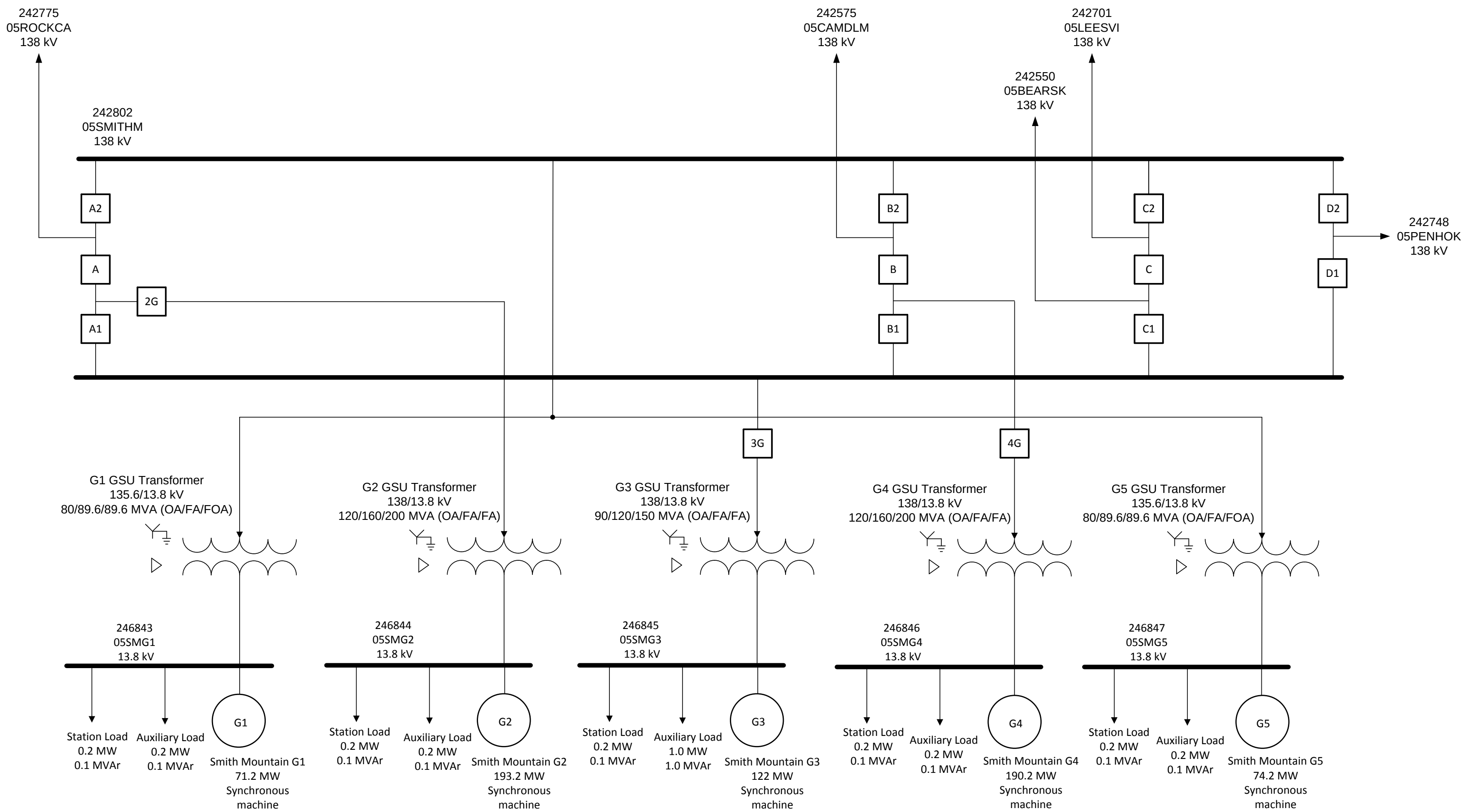


Figure 1: AA2-070 Plant Model

Table 3: AA2-070 Plant Model

	Impact Study Data	Model
Hydroelectric Turbine Generator G1	71.2 MW hydroelectric turbine generator MVA base = 69.5 MVA Nominal power factor = 0.95 Reactive power capability at max gross energy output: Lagging: 38 MVAr Leading -38 MVAr Unsaturated sub-transient reactance= 0.34 pu @ MVA base	71.2 MW hydroelectric turbine generator Pgen 71.2 MW Pmax 71.2 MW Pmin -79.0 MW Qgen -0.8 MVAr Qmax 38.0 MVAr Qmin -38.0 MVAr Mbase 69.5 MVA Zsource j0.34 pu @ Mbase
Hydroelectric Turbine Generator G2	193.2 MW hydroelectric turbine generator MVA base = 212.5 MVA Nominal power factor = 0.95 Reactive power capability at max gross energy output: Lagging: 70 MVAr Leading -42 MVAr Unsaturated sub-transient reactance= 0.49 pu @ MVA base	193.2 MW hydroelectric turbine generator Pgen 193.2 MW Pmax 193.2 MW Pmin 0.0 MW Qgen -11.9 MVAr Qmax 70.0 MVAr Qmin -42.0 MVAr Mbase 212.5 MVA Zsource j0.49 pu @ Mbase
Hydroelectric Turbine Generator G3	122 MW hydroelectric turbine generator MVA base = 144.18 MVA Nominal power factor = 0.8 Reactive power capability at max gross energy output: Lagging: 78 MVAr Leading -58 MVAr Unsaturated sub-transient reactance= 0.29 pu @ MVA base	122 MW hydroelectric turbine generator Pgen 122.0 MW Pmax 122.0 MW Pmin -135.0 MW Qgen -23.5 MVAr Qmax 78.0 MVAr Qmin -58.0 MVAr Mbase 144.18 MVA Zsource j0.29 pu @ Mbase

	Impact Study Data	Model
Hydroelectric Turbine Generator G4	190.2 MW hydroelectric turbine generator MVA base = 212.5 MVA Nominal power factor = 0.95 Reactive power capability at max gross energy output: Lagging: 76 MVAr Leading -44 MVAr Unsaturated sub-transient reactance= 0.49 pu @ MVA base	190.2 MW hydroelectric turbine generator Pgen 190.2 MW Pmax 190.2 MW Pmin 0.0 MW Qgen -12.3 MVAr Qmax 76.0 MVAr Qmin -44.0 MVAr Mbase 212.5 MVA Zsource j0.49 pu @ Mbase
Hydroelectric Turbine Generator G5	74.2 MW hydroelectric turbine generator MVA base = 69.5 MVA Nominal power factor = 0.95 Reactive power capability at max gross energy output: Lagging: 30 MVAr Leading -30 MVAr Unsaturated sub-transient reactance= 0.34 pu @ MVA base	74.2 MW hydroelectric turbine generator Pgen 74.2 MW Pmax 74.2 MW Pmin -79.0 MW Qgen -0.7 MVAr Qmax 30.0 MVAr Qmin -30.0 MVAr Mbase 69.5 MVA Zsource j0.34 pu @ Mbase
Hydroelectric Turbine Generator GSU Transformer G1	135.6/13.8 kV YNd 80/89.6/89.6 MVA (OA/FA/FOA) Transformer base = 80 MVA Impedance 0.00396 + j 0.1025 pu @ 80 MVA Number of taps = 5 Tap step size = 2.5%	135.6/13.8 kV 80/89.6/89.6 MVA Transformer base = 80 MVA Impedance 0.00396 + j 0.1025 pu @ Mbase Number of taps = 5 Tap step size = 2.5%

	Impact Study Data	Model
Hydroelectric Turbine Generator GSU Transformer G2	138/13.8 kV YNd 120/160/200 MVA (OA/FA/FA) Transformer base = 200 MVA Impedance 0.00239 + j 0.1299 pu @ 200 MVA Number of taps = 5 Tap step size = 2.5%	138/13.8 kV 120/160/200 MVA Transformer base = 200 MVA Impedance 0.00239 + j 0.1299 pu @ Mbase Number of taps = 5 Tap step size = 2.5%
Hydroelectric Turbine Generator GSU Transformer G3	138/13.8 kV YNd 90/120/150 MVA (OA/FA/FA) Transformer base = 150 MVA Impedance 0.00262 + j 0.0822 pu @ 150 MVA Number of taps = 5 Tap step size = 2.5%	138/13.8 kV 90/120/150 MVA Transformer base = 150 MVA Impedance 0.00262 + j 0.0822 pu @ Mbase Number of taps = 5 Tap step size = 2.5%
Hydroelectric Turbine Generator GSU Transformer G4	138/13.8 kV YNd 120/160/200 MVA (OA/FA/FA) Transformer base = 200 MVA Impedance 0.00241 + j 0.1297 pu @ 200 MVA Number of taps = 5 Tap step size = 2.5%	138/13.8 kV 120/160/200 MVA Transformer base = 200 MVA Impedance 0.00241 + j 0.1297 pu @ Mbase Number of taps = 5 Tap step size = 2.5%
Hydroelectric Turbine Generator GSU Transformer G5	135.6/13.8 kV YNd 80/89.6/89.6 MVA (OA/FA/FOA) Transformer base = 80 MVA Impedance 0.004 + j 0.1025 pu @ 80 MVA Number of taps = 5 Tap step size = 2.5%	135.6/13.8 kV 80/89.6/89.6 MVA Transformer base = 80 MVA Impedance 0.004 + j 0.1025 pu @ Mbase Number of taps = 5 Tap step size = 2.5%
Station Load	1 MW + 0.5 MVAr	0.2 MW + 0.1 MVAr at each generator bus (switched out in model)

	Impact Study Data	Model
Auxiliary Loads	1.8 MW + 1.4 MVAr	0.2 MW + 0.1 MVAr at generator bus G1, G2, G4 and G5 1.0 MW + 1.0 MVAr at G3 generator bus

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[3] and discussions with PJM.
The selected load flow scenario is the RTEP 2019 light load case with the following modifications:

a) Addition of all applicable queue projects prior to AA2-070.

b) Addition of AA2-070 queue project.

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

Generation within the PJM500 system (area 225 in the PSS/E case) and within the vicinity of AA2-070 was dispatched online at maximum output (PMAX). The dispatch is given in Attachment 5. The circuits that are loaded above 90% in the vicinity of AA2-070 are given in Table 3.

Table 4: Circuit overloads within the vicinity of AA2-070

From Bus		To Bus		Loading (%)[4]
Number	Name	Number	Name	
242741	05OTTER 138.00	314667	4ALTVSTA 138.00	104
242687	05JOHNMT 138.00	242741	05OTTER 138.00	101
242687	05JOHNMT 138.00	242734	05NEWLDN 138.00	97
242620	05DANVL2 138.00	242631	05EDAN 1 138.00	106

[3] Manual 14B: PJM Region Transmission Planning Process, Rev 19, September 15 2011, Attachment G : PJM Stability, Short Circuit, and Special RTEP Practices and Procedures.
[4] Loading calculated as a percentage of current rating A.

4. Fault Cases

AA2-070 was tested for compliance with NERC, PJM and other applicable criteria. Faults were applied to transmission circuits and transformers connected to the POI or one bus removed[5]. 97 contingencies were studied, each with a 10 second simulation time period. Contingencies to be studied include:

a) Steady state operation

b) Three phase faults with normal clearing time

c) Three phase faults with loss of multiple-circuit tower line

d) Single phase faults with single phase stuck breaker

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

f) Single-phase bus faults with normal clearing time

Buses at which the faults listed above will be applied are

- Smith Mountain 138 kV POI
- Cloverdale 138, 345, 500 and 765 kV
- Matt Funk 345 kV
- Opossum Creek 138 kV
- Leesville 138 kV
- Westlake 138 kV
- East Danville 138 and 230 kV

Additional delayed (Zone 2) clearing at remote end faults will be applied on lines from Glen Lyn 138 kV, Huntington 138 kV, Reusens 138 kV, Roanoke 138 kV, Peaksview 138 kV, East Lynchburg 138 kV, Joshua Falls 138 kV, Altavista 138 kV and Blaine 138 kV toward the queue project.

A complete list of the contingencies that will be studied is outlined in Table 5 to Table 11. Clearing times listed are as per revision 17 of 2015 Revised Clearing times for each PJM company spreadsheet.

Attachment 2 contains the one line diagram of the AEP network in the vicinity of AA2-070 and an updated breaker arrangement for Cloverdale 345, 500 and 765 kV.

[5] One bus removed from the POI refers to buses with transmission circuit breakers, not tee-offs or buses with only supply circuit breakers.

5. Evaluation Criteria

The results should indicate that, for the fault contingencies to be tested on the AA2-070 evaluation:

a) AA2-070 is able to ride through the faults (except for faults where protective action trips AA2-070),

b) the system with AA2-070 included is transiently stable and post-contingency oscillations should be positively damped with a damping margin of at least 3%.

7. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6 with results summarized in Table 5 to Table 11.
The results indicate that for the 95 of the 97 fault contingencies tested on the RTEP 2019 light load case:

c) The system with AA2-070 included was found to be transiently stable,

d) AA2-070 was able to ride through the faults (except for faults where protective action tripped AA2-070).

The stability criteria were not met for two stuck breaker contingencies (1B.03 and 1B.05) due to unanticipated tripping of units at Smith Mountain. Tests using the pre-uprate model for Smith Mountain showed that the uprate (AA2-070) is responsible for the unanticipated tripping of units during stuck breaker simulations 1B.03 and 1B.05. Additional testing showed that a reduction in the total stuck breaker clearing time from 16.0 cycles to 14.0 cycles mitigates the instability.
The unanticipated tripping and insufficient damping can also be mitigated if the units are operated with the terminal voltages at or above the values shown in Table 5.

Table 5: Minimum required terminal voltages

Generating unit	Terminal Voltage (pu)
Smith Mountain G1	0.98
Smith Mountain G2	0.99
Smith Mountain G3	1.00
Smith Mountain G4	0.99
Smith Mountain G5	0.98

It should be noted that the post fault responses of all Smith Mountain units were underdamped, with modal analysis of the active power response showing damping margins as low as 3.2%. Although the required damping margin was met for all contingencies tested, the addition of power system stabilizers on the Smith Mountain units may improve the damping of post fault oscillations.

Table 5: Steady State Operation

Fault ID	Duration	Result
SS.01	Steady state 20 sec	Stable

Table 6: Three-phase Faults with Normal Clearing

Fault ID	Fault description	Clearing Time (Cycles)	Result
3N.01	Fault at Smith Mountain 138 kV POI on Units 1 and 5.	5.5	Stable (Trips SMG 1 and 5)
3N.02	Fault at Smith Mountain 138 kV POI on Unit 2.	5.5	Stable (Trips SMG 2)
3N.03	Fault at Smith Mountain 138 kV POI on Unit 3.	5.5	Stable (Trips SMG 3)
3N.04	Fault at Smith Mountain 138 kV POI on Unit 4.	5.5	Stable (Trips SMG 4)
3N.05	Fault at Smith Mountain 138 kV POI on Rockcastle – Moneta – Meads Store – Cloverdale circuit.	5.5	Stable
3N.06	Fault at Smith Mountain 138 kV POI on Candlers Mountain – Rustberg – Opossum Creek circuit.	5.5	Stable
3N.07	Fault at Smith Mountain 138 kV POI on Leesville circuit. Trips Leesville unit 1.	5.5	Stable
3N.08	Fault at Smith Mountain 138 kV POI on Penhook – Westlake circuit.	5.5	Stable
3N.09	Fault at Smith Mountain 138 kV POI on Bearskin – Banister – East Danville circuit.	5.5	Stable
3N.10	Fault at Cloverdale 138 kV on Meads Store – Moneta – Rockcastle – Smith Mountain circuit.	5.5	Stable
3N.11	Fault at Cloverdale 138 kV on Catawba – Kimballton – Glen Lyn circuit.	5.5	Stable
3N.12	Fault at Cloverdale 138 kV on Huntington circuit.	5.5	Stable
3N.13	Fault at Cloverdale 138 kV on Lake Forest – Centerville – Ivy Hill – Coffee – Reusens circuit.	5.5	Stable
3N.14	Fault at Cloverdale 138 kV on Bonsack – Vinto – Roanoke circuit.	5.5	Stable
3N.15	Fault at Cloverdale 138 kV on Burlington Heights – West Salem – Matt Funk circuit.	5.5	Stable
3N.16	Fault at Cloverdale 138 kV on 138/345 kV Transformers 1A and 1B.	5.5	Stable
3N.17	Fault at Cloverdale 138 kV on 138/345 kV Transformer 3.	5.5	Stable
3N.18	Fault at Cloverdale 345 kV on Matt Funk circuit.	4.5	Stable
3N.19	Fault at Cloverdale 345 kV on 345/500 kV Transformer 6A.	4.5	Stable
3N.20	Fault at Cloverdale 345 kV on 345/765 kV Transformer 10.	4.5	Stable
3N.21	Fault at Cloverdale 500 kV on Lexington circuit.	4.5	Stable
3N.22	Fault at Cloverdale 500 kV on 500/765 kV Transformer 14.	4.5	Stable
3N.23	Fault at Cloverdale 765 kV on Jackson Ferry circuit.	4.5	Stable

Fault ID	Fault description	Clearing Time (Cycles)	Result
3N.24	Fault at Cloverdale 765 kV on Joshua Falls circuit.	4.5	Stable
3N.25	Fault at Opossum Creek 138 kV on Rustberg – Candlers Mountain – Smith Mountain circuit.	5.5	Stable
3N.26	Fault at Opossum Creek 138 kV on South Lynchburg – Brookville – Graves Mill – Reusens circuit.	5.5	Stable
3N.27	Fault at Opossum Creek 138 kV on Peaksview circuit.	5.5	Stable
3N.28	Fault at Opossum Creek 138 kV on East Lynchburg circuit.	5.5	Stable
3N.29	Fault at Opossum Creek 138 kV on Joshua Falls circuit.	5.5	Stable
3N.30	Fault at Opossum Creek 138 kV on synchronous condenser C.	5.5	Stable
3N.31	Fault at Leesville 138 kV on Smith Mountain circuit. Trips Leesville unit 1.	5.5	Stable
3N.32	Fault at Leesville 138 kV on Altavista circuit.	5.5	Stable
3N.33	Fault at Westlake 138 kV on Penhook – Smith Mountain circuit.	5.5	Stable
3N.34	Fault at Westlake 138 kV on Blaine circuit.	5.5	Stable
3N.35	Fault at East Danville 138 kV on Banister – Bearskin – Smith Mountain circuit.	5.5	Stable
3N.36	Fault at East Danville 138 kV on Danville circuit.	5.5	Stable
3N.37	Fault at East Danville 138 kV on East Monument circuit.	5.5	Stable
3N.38	Fault at East Danville 138 kV on Rocksprings circuit.	5.5	Stable
3N.39	Fault at East Danville 138 kV on 138/230 kV Transformer 4.	5.5	Stable

Table 7: Three-phase Faults With Loss Of Multiple-Circuit Tower Line

Fault ID	Fault description	Clearing Time (Cycles)	Result
3T.01	Fault at Matt Funk 345 kV on Cloverdale circuit resulting in tower failure. Fault cleared with loss of Kanawha River circuit. CONTINGENCY '6186'	4.5	Stable
3T.02	Fault at Cloverdale 138 kV on Burlington Heights – West Salem – Matt Funk circuit resulting in tower failure. Fault cleared with loss of Cloverdale – Catawba – Kimballton – Glen Lyn circuit. CONTINGENCY '410'	5.5	Stable

Table 8: Single-phase Faults with Stuck Breaker

Fault ID	Fault description	Clearing Time normal & delayed (Cycles)	Result
1B.01	Fault at Smith Mountain 138 kV POI on Rockcastle – Moneta – Meads Store – Cloverdale circuit. Breaker A stuck. Fault cleared with the loss of Unit 2.	5.5 / 16.0	Stable (Trips SMG 2)
1B.02	Fault at Smith Mountain 138 kV POI on Candlers Mountain – Rustberg – Opossum Creek circuit. Breaker B2 stuck. Fault cleared with the loss of Units 1 and 5.	5.5 / 16.0	Stable (Trips SMG 1 and 5)
1B.03	Fault at Smith Mountain 138 kV POI on Leesville circuit. Breaker C stuck. Trips Leesville unit 1. Fault cleared with the loss of Bearskin – Banister – East Danville circuit.	5.5 / 16.0	Unstable Unanticipated trip of SMG 2 and 4
1B.04	Fault at Smith Mountain 138 kV POI on Penhook – Westlake circuit. Breaker D1 stuck. Fault cleared with the loss of Unit 3.	5.5 / 16.0	Stable (Trips SMG 3)
1B.05	Fault at Smith Mountain 138 kV POI on Bearskin – Banister – East Danville circuit. Breaker C1 stuck. Fault cleared with the loss of Unit 3.	5.5 / 16.0	Unstable Unanticipated trip of SMG 2 (Trips SMG 3)
1B.06	Fault at Cloverdale 138 kV on Meads Store – Moneta – Rockcastle – Smith Mountain circuit. Breaker A stuck. Fault cleared with the loss of Bonsack – Vinto – Roanoke circuit.	5.5 / 16.0	Stable
1B.07	Fault at Cloverdale 138 kV on Catawba – Kimballton – Glen Lyn circuit. Breaker C stuck. Fault cleared with the loss of 138/345 kV Transformers 11A and 11B.	5.5 / 16.0	Stable
1B.08	Fault at Cloverdale 138 kV on Huntington circuit. Breaker B stuck. Fault cleared with the loss of 138/345 kV Transformer 3.	5.5 / 16.0	Stable
1B.09	Fault at Cloverdale 138 kV on Lake Forest – Centerville – Ivy Hill – Coffee – Reusens circuit. Breaker E2 stuck. Fault cleared with the loss of Bus 2.	5.5 / 16.0	Stable
1B.10	Fault at Cloverdale 138 kV on Bonsack – Vinto – Roanoke circuit. Breaker A stuck. Fault cleared with the loss of Meads Store – Moneta – Rockcastle – Smith Mountain circuit.	5.5 / 16.0	Stable
1B.11	Fault at Cloverdale 138 kV on Burlington Heights – West Salem – Matt Funk circuit. Breaker D1 stuck. Fault cleared with the loss of Bus 1.	5.5 / 16.0	Stable
1B.12	Fault at Cloverdale 138 kV on 138/345 kV Transformers 11A and 11B. Breaker C1 stuck. Fault cleared with the loss of Bus 1.	5.5 / 16.0	Stable

Fault ID	Fault description	Clearing Time normal & delayed (Cycles)	Result
1B.13	Fault at Cloverdale 138 kV on 138/345 kV Transformer 3. Breaker B1 stuck. Fault cleared with the loss of Bus 1.	5.5 / 16.0	Stable
1B.14	Fault at Cloverdale 345 kV on Matt Funk circuit. Breaker P1 stuck. Fault cleared with the loss of 138/345 kV Transformers 11A and 11B.	4.5 / 15.0	Stable
1B.15	Fault at Cloverdale 345 kV on 345/500 kV Transformer 6A. Breaker stuck to Bus 2. Fault cleared with the loss of 138/345 kV Transformer 3.	4.5 / 15.0	Stable
1B.16	Fault at Cloverdale 345 kV on 345/765 kV Transformer 10. Breaker stuck to Bus 1. Fault cleared with the loss of 138/345 kV Transformers 11A and 11B.	4.5 / 15.0	Stable
1B.17	Fault at Cloverdale 500 kV on Lexington circuit. Breaker stuck to Bus 2. Fault cleared with no additional loss.	4.5 / 12.0	Stable
1B.18	Fault at Cloverdale 500 kV on 500/765 kV Transformer 14. Breaker stuck to Transformer 6A. Fault cleared with the loss of 345/500 kV Transformer 6A.	4.5 / 12.0	Stable
1B.19	Fault at Cloverdale 765 kV on Jackson Ferry circuit. Breaker stuck to Bus 2. Fault cleared with no additional loss.	4.5 / 12.0	Stable
1B.20	Fault at Cloverdale 765 kV on Joshua Falls circuit. Breaker stuck to Bus 2. Fault cleared with no additional loss.	4.5 / 12.0	Stable
1B.21	Fault at Opossum Creek 138 kV on Rustberg – Candlers Mountain – Smith Mountain circuit. Breaker D1 stuck. Fault cleared with the loss of Bus 1.	4.5 / 15.0	Stable
1B.22	Fault at Opossum Creek 138 kV on South Lynchburg – Brookville – Graves Mill – Reusens circuit. Breaker A2 stuck. Fault cleared with the loss of Joshua Falls circuit.	4.5 / 15.0	Stable
1B.23	Fault at Opossum Creek 138 kV on Peaksview circuit. Breaker C stuck. Fault cleared with the loss of Bus 1.	4.5 / 15.0	Stable
1B.24	Fault at Opossum Creek 138 kV on East Lynchburg circuit. Breaker B1 stuck. Fault cleared with the loss of Bus 2.	4.5 / 15.0	Stable
1B.25	Fault at Opossum Creek 138 kV on Joshua Falls circuit. Breaker A stuck. Fault cleared with the loss of synchronous condenser C.	4.5 / 15.0	Stable
1B.26	Fault at Leesville 138 kV on Smith Mountain circuit. Breaker A stuck. Fault cleared with the loss of Altavista circuit.	4.5 / 15.0	Stable

Fault ID	Fault description	Clearing Time normal & delayed (Cycles)	Result
1B.27	Fault at Westlake 138 kV on Penhook – Smith Mountain circuit. Breaker A stuck. Fault cleared with the loss of Blaine circuit.	4.5 / 15.0	Stable
1B.28	Fault at East Danville 138 kV on Banister – Bearskin – Smith Mountain circuit. Breaker M stuck. Fault cleared with the loss of Bus 2.	4.5 / 15.0	Stable
1B.29	Fault at East Danville 138 kV on Danville circuit. Breaker L stuck. Fault cleared with the loss of Bus 1.	4.5 / 15.0	Stable
1B.30	Fault at East Danville 138 kV on East Monument circuit. Breaker P stuck. Fault cleared with the loss of Bus 1 and 2.	4.5 / 15.0	Stable
1B.31	Fault at East Danville 138 kV on Rocksprings circuit. Breaker J stuck. Fault cleared with the loss of Bus 1.	4.5 / 15.0	Stable

Table 9: Single-phase Bus Faults With Normal Clearing

Fault ID	Fault description	Clearing Time (Cycles)	Result
1S.01	Fault at Cloverdale 345 kV on Bus 1. Fault cleared with loss of 138/345 kV Transformers 11A and 11B. CONTINGENCY '1388_C1'	4.5	Stable
1S.02	Fault at Cloverdale 345 kV on Bus 2. Fault cleared with loss of 138/345 kV Transformer 3. CONTINGENCY '328_C1'	4.5	Stable
1S.03	Fault at Cloverdale 765 kV on Bus 1. Fault cleared with loss of 765/345 kV Transformer 10. CONTINGENCY '6329_C1_05CLOVRD 765-1'	4.5	Stable
1S.04	Fault at East Danville 230 kV on Bus 1. Fault cleared with loss of East Danville 138 kV on Bus 1. CONTINGENCY '2816_C1_05EDANV1 230-1_WOMOAB'	5.5	Stable
1S.05	Fault at East Danville 230 kV on Bus 2. Fault cleared with loss of East Danville 138 kV on Bus 2. CONTINGENCY '3194_C1_05EDANV2 230-2_WOMOAB'	5.5	Stable

Table 10: Single-phase Faults With Delayed (Zone 2) Clearing at line end closest to AA2-070

Fault ID	Fault description	Clearing Time (Cycles)	Result
1D.01	Fault at 80% of line from Smith Mountain on Cloverdale – Meads Store – Moneta – Rockcastle – Smith Mountain circuit. Delayed clearing at Smith Mountain.	5.5 / 60	Stable
1D.02	Fault at 80% of line from Cloverdale on Glen Lyn – Kimballton – Catawba – Cloverdale circuit. Delayed clearing at Cloverdale.	5.5 / 60	Stable
1D.03	Fault at 80% of line from Cloverdale on Huntington – Cloverdale circuit. Delayed clearing at Cloverdale.	5.5 / 60	Stable
1D.04	Fault at 80% of line from Cloverdale on Reusens – Coffee – Ivy Hill – Centerville - Lake Forest – Cloverdale circuit. Delayed clearing at Cloverdale.	5.5 / 60	Stable
1D.05	Fault at 80% of line from Cloverdale on Roanoke – Vinto – Bonsack – Cloverdale circuit. Delayed clearing at Cloverdale.	5.5 / 60	Stable
1D.06	Fault at 80% of line from Cloverdale on Matt Funk – West Salem – Burlington Heights – Cloverdale circuit. Delayed clearing at Cloverdale.	5.5 / 60	Stable
1D.07	Fault at 80% of line from Smith Mountain on Opossum Creek – Rustberg – Candlers Mountain – Smith Mountain circuit. Delayed clearing at Smith Mountain.	5.5 / 60	Stable
1D.08	Fault at 80% of line from Opossum Creek on Reusens – Graves Mill – Brookville – South Lynchburg – Opossum Creek circuit. Delayed clearing at Opossum Creek.	5.5 / 60	Stable
1D.09	Fault at 80% of line from Opossum Creek on Peaksview – Opossum Creek circuit. Delayed clearing at Opossum Creek.	5.5 / 60	Stable
1D.10	Fault at 80% of line from Opossum Creek on East Lynchburg – Opossum Creek circuit. Delayed clearing at Opossum Creek.	5.5 / 60	Stable
1D.11	Fault at 80% of line from Opossum Creek on Joshua Falls – Opossum Creek circuit. Delayed clearing at Opossum Creek.	5.5 / 60	Stable
1D.12	Fault at 80% of line from Smith Mountain on Leesville – Smith Mountain circuit. Delayed clearing at Smith Mountain.	5.5 / 60	Stable
1D.13	Fault at 80% of line from Leesville on Altavista – Leesville circuit. Delayed clearing at Leesville.	5.5 / 60	Stable
1D.14	Fault at 80% of line from Smith Mountain on Westlake – Penhook – Smith Mountain circuit. Delayed clearing at Smith Mountain.	5.5 / 60	Stable
1D.15	Fault at 80% of line from Westlake on Blaine – Westlake circuit. Delayed clearing at Westlake.	5.5 / 60	Stable

Fault ID	Fault description	Clearing Time (Cycles)	Result
1D.16	Fault at 80% of line from Smith Mountain on East Danville – Banister – Bearskin – Smith Mountain circuit. Delayed clearing at Smith Mountain.	5.5 / 60	Stable
1D.17	Fault at 80% of line from East Danville on Danville – East Danville circuit. Delayed clearing at East Danville.	5.5 / 60	Stable
1D.18	Fault at 80% of line from East Danville on East Monument – East Danville circuit. Delayed clearing at East Danville.	5.5 / 60	Stable
1D.19	Fault at 80% of line from East Danville on Rocksprings – East Danville circuit. Delayed clearing at East Danville.	5.5 / 60	Stable

Table 11 Single-phase Faults with Stuck Breaker

Fault ID	Fault description	Clearing Time normal & delayed (Cycles)	Result Increased Terminal Voltages
1B.03	Fault at Smith Mountain 138 kV POI on Leesville circuit. Breaker C stuck. Trips Leesville unit 1. Fault cleared with the loss of Bearskin – Banister – East Danville circuit	5.5 / 16.0	Stable
1B.05	Fault at Smith Mountain 138 kV POI on Bearskin – Banister – East Danville circuit. Breaker C1 stuck. Fault cleared with the loss of Unit 3.	5.5 / 16.0	Stable (Trips SMG 3)

(The Attachments listed below are available upon request)

Attachment 1. AA2-070 Impact Study Data

Attachment 2. AEP One Line Diagram

Attachment 3. PSS/E Model One Line Diagram

Attachment 4. AA2-070 PSS/E Dynamic Model

Attachment 5. AA2-070 AEP Area Dispatch

Attachment 6. Plots from Dynamic Simulations