Attachment H

LGE-GIS-2019-029 GI System Impact Study

LGE-GIS-2019-029
Generation Interconnection Request
System Impact Study Report

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1. Introduction

TranServ International, Inc. (TranServ), as an Independent Transmission Organization (ITO) of Louisville Gas & Electric/Kentucky Utilities (LG&E and KU), has received the following Generation Interconnection (GI) Request to provide a Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) to the LG&E and KU Transmission Network. TranServ has evaluated the GI Request listed in Table 1-1. This report contains the System Impact Study (SIS) results for GI Request LGE-GIS-2019-029.

Table 1-1
Request Details

Queue Position	Queue Date	County	State	Max Output (MW)	Point of Inter-connection	In-Service Date	Inter-connection Service Type	Generator Type
LGE-GIS-2019-029	11/08/2019	Hardin County	KY	100	Black Branch-Hardinsburg 138kV (324047 - 324360)	11/15/2022	NRIS/ERIS	Solar

As shown in Table 1-1, the LGE-GIS-2019-029 request seeks to interconnect a 100 MW generator by connecting to the Black Branch-Hardinsburg 138kV line. The requested in-service date of the LGE-GIS-2019-029 request is November 15, 2022. A one-line diagram of the proposed interconnection is given in Appendix A. This SIS analyzed the impact of this addition, located in Hardin County, Kentucky, in accordance with the LG&E and KU Generator Interconnection Study Criteria and LG&E and KU Planning Guidelines. Both of these documents are posted on the LG&E and KU OASIS.

An Ad Hoc Study Group was involved in the study process.

The GI request, LGE-GIS-2019-029, is an NRIS and an ERIS request and thus was studied as sourcing from the new generation connecting to the Bardstown-Brown CT 138 kV line and then sinking into the LG&E and KU system in merit order (NRIS) or beyond the LG&E and KU Balancing Authority (BA) equally in 4 directions (North, South, East, and West) (ERIS). The simulations performed considered steady-state contingencies in Categories P0, P1, P2 EHV, P3, and P4 EHV and stability disturbances in Categories P0, P1, P2, P3, P4, P5, and P7 of the current effective versions of North American Electric Reliability Corporation (NERC) TPL-004 standards and the LG&E and KU Planning Guidelines.

The subject request was evaluated using 2023 Off Peak, 2023 Summer Peak, and 2030 Summer Peak steady state power flow model with roots in the LG&E and KU 2021 Transmission Expansion

Plan (TEP) Base Case Study (BCS) models, 2021 Summer, 2024 Light Load, and 2029 Summer Stability models with roots in LG&E and KU's 2020 TEP Stability Models and a short circuit model with roots in LG&E and KU's 2020 TEP Short Circuit Models all of which include the 2020 TEP approved projects and as appropriate approved project changes.

This study included the effect of all earlier queued LG&E and KU GI requests. This study also included the effect of all confirmed Transmission Service Requests (TSRs). A Contingent Facility Analysis was performed for all planned transmission improvements associated with an earlier queued LG&E and KU GI request. The results of that analysis are given in Section 1.1. The study determined that there are no contingent facilities for the GI-2019-029 request. Representation of the confirmed TSRs may have necessitated representation of associated planned transmission improvements. Thus, it is important to realize that if the planned improvements do not come to fruition, the subject request's impact on the transmission system as identified by this study may become invalid and a revised study may become necessary before GI service can be granted.

1.1 Contingent Facility Analysis

Since prior queued requests are contingent upon construction of network upgrades, a contingent facility analysis was performed. The results of that analysis are shown in Tables 1-2 and 1-3 for NRIS and ERIS respectively.

As can be seen from Tables 1-2 and 1-3, none of the potential contingent facilities were shown to overload in the GI-2019-029 Contingent Facility Analysis and the GI-2019-029 DF on the potential contingent facilities was less than the 20% threshold for determining contingent facilities. Thus there are no GI-2019-029 contingent facilities.

Table 1-2
Contingent Facility Analysis Results for NRIS

Year/ Season	Dispatch	Facility	Rating	Pre Project	Post Project	DF	Contingency
				MW	MW		
2023OP	mbr_nits	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	65	37.49	35.98	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	bullrun1_s	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	67	44.69	43.25	-1%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	mbr_nits	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	62	36.20	34.70	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	wbnp1_s	2LEITCHF CIT69.000 TO 2LEITCHF E 69.000 1	79	48.88	47.43	-1%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	wbnp1_s	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	67	45.66	44.22	-1%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	47	31.99	30.37	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	50	35.95	34.31	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	42	29.66	28.05	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2EASTVIEW 69.000 TO 2STEPHENSBRG69.000 1	45	24.49	22.96	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	50	36.00	34.36	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	br3_merit_miso	4BONNIEVILLE138.00 TO 4LEBANON WES138.00 1	83	55.93	56.59	1%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2023S	br3_merit_miso	4BONNIEVILLE138.00 TO 4MERE TVA 138.00 1	121	91.82	90.69	-1%	OPEN [4LEITCHFIELD138.00] [4SHREWSBURY 138.00] CKT 1
2023S	br3_merit_miso	4LEBANON WES138.00 TO 4LEBANON 138.00 1	83	47.69	48.30	1%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2023S	wbnp1_s	4LEITCHFIELD138.00 TO 2LEITCHFIELD69.000 1	82	52.38	51.21	-1%	OPEN [4BONNIEVILLE138.00] [4LEBANON WES138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIE KU 69.000] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2023S	wbnp1_s	4SHREWSBURY 138.00 TO GI-2019-015P138.00 1 (4OHIO COUNTY138.00 TO 4SHREWSBURY 138.00)	210	177.90	176.60	-1%	OPEN [7DAVIESS 345.00] [7WILSON 345.00] CKT 1
2023S	wilson_w	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	245	219.67	218.52	-1%	OPEN [5CRITTENDEN 161.00] [5LIVNGSTN CO161.00] CKT 1: OPEN [5CRITTENDEN 161.00] [5MORGANFIELD161.00] CKT 1: OPEN [5CRITTENDEN 161.00] [2CRITTENDEN 69.000] CKT 1
2030S	wbnp1_s	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	47	31.88	29.93	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	wbnp1_s	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	50	35.77	33.76	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1

Year/ Season	Dispatch	Facility	Rating	Pre Project MW	Post Project MW	DF	Contingency
2030S	wbnp1_s	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	42	29.62	27.67	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	br3_merit_miso	2EASTVIEW 69.000 TO 2STEPHENSBRG69.000 1	45	23.91	22.15	-2%	OPEN [4BONNIEVILLE138.00] [4LEBANON WES138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIE KU 69.000] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	wbnp1_s	2LEITCHF CIT69.000 TO 2LEITCHF E 69.000 1	66	41.36	39.33	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	wbnp1_s	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	50	35.83	33.81	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	cpr2_n	4BONNIEVILLE138.00 TO 4LEBANON WES138.00 1	83	47.98	49.58	2%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	cpr2_n	4BONNIEVILLE138.00 TO 4MERE TVA 138.00 1	121	87.85	87.24	-1%	OPEN [4LEITCHFIELD138.00] [4SHREWSBURY 138.00] CKT 1
2030S	cpr2_n	4LEBANON WES138.00 TO 4LEBANON 138.00 1	83	40.17	41.69	2%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	wbnp1_s	4LEITCHFIELD138.00 TO 2LEITCHFIELD69.000 1	82	51.65	50.45	-1%	OPEN [4BONNIEVILLE138.00] [4LEBANON WES138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIE KU 69.000] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	wbnp1_s	4SHREWSBURY 138.00 TO GI-2019-015P138.00 1 (4OHIO COUNTY138.00 TO 4SHREWSBURY 138.00)	210	174.80	173.80	-1%	OPEN [7DAVIESS 345.00] [7HARDIN CO 345.00] CKT 1
2030S	mbr_nits	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	194	165.70	164.69	-1%	None
2030S	Base Dispatch	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	194	163.81	162.80	-1%	None
2030S	wilson_w	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	245	119.01	119.00	0%	OPEN [5LIVNGSTN CO161.00] [G2017-02 TP 161.00] CKT 1
2030S	19-2_merit_miso	5LIVNGSTN CO161.00 TO G2017-02 TP 161.00 1	245	118.89	118.90	0%	OPEN [5EARLINGTN N161.00] [5N PRINCETON161.00] CKT 1
2030S	19-2_merit_miso	5N PRN LIV R161.00 TO GI-2019-023P161.00 1	245	192.40	191.22	-1%	OPEN [5CRITTENDEN 161.00] [5LIVNGSTN CO161.00] CKT 1: OPEN [5CRITTENDEN 161.00] [5MORGANFIELD161.00] CKT 1: OPEN [5CRITTENDEN 161.00] [2CRITTENDEN 69.000] CKT 1

Table 1-3
Contingent Facility Analysis Results for ERIS

Year/ Season	Dispatch	Facility	Rating	Pre Project	Post Project	DF	Contingency
				MW	MW		
2023OP	gib2_w	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	65	36.79	34.84	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	gib2_w	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	67	39.18	37.19	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	gib2_w	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	62	35.51	33.56	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023OP	gib2_w	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	67	39.25	37.25	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	47	28.84	26.91	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	50	32.73	30.78	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	42	26.52	24.60	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	50	32.78	30.82	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	br3_merit_miso	4BONNIEVILLE138.00 TO 4LEBANON WES138.00 1	83	55.45	56.94	1%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2023S	br3_merit_miso	4BONNIEVILLE138.00 TO 4MERE TVA 138.00 1	121	89.57	88.62	-1%	OPEN [4LEITCHFIELD138.00] [2LEITCHFIELD69.000] CKT 1
2023S	br3_merit_miso	4LEBANON WES138.00 TO 4LEBANON 138.00 1	83	47.23	48.63	1%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2023S	wbnp1_s	4LEITCHFIELD138.00 TO 2LEITCHFIELD69.000 1	82	50.08	48.68	-1%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2023S	wbnp1_s	4SHREWSBURY 138.00 TO GI-2019-015P138.00 1 (4OHIO COUNTY138.00 TO 4SHREWSBURY 138.00)	210	171.90	169.80	-2%	OPEN [7DAVIESS 345.00] [7WILSON 345.00] CKT 1
2030S	wbnp1_s	2CLARKSON 69.000 TO 2M-V CLARK T69.000 1	47	28.25	26.27	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	wbnp1_s	2CLARKSON 69.000 TO 2WARREN TIE 69.000 1	50	32.73	30.66	-2%	OPEN [4BONNIEVILLE138.00] [4LEBANON WES138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIE KU 69.000] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	wbnp1_s	2EASTVIEW 69.000 TO 2M-V CLARK T69.000 1	42	26.00	24.02	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1
2030S	wbnp1_s	2EASTVIEW 69.000 TO 2STEPHENSBRG69.000 1	45	21.19	19.29	-2%	OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1

Year/ Season	Dispatch	Facility	Rating	Pre Project	Post Project	DF	Contingency
				MW	MW		
2030S	wbnp1_s	2LEITCHF E 69.000 TO 2WARREN TIE 69.000 1	50	32.78	30.71	-2%	OPEN [4BONNIEVILLE138.00] [4LEBANON WES138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [4MERE TVA 138.00] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIE KU 69.000] CKT 1: OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	br3_merit_miso	4BONNIEVILLE138.00 TO 4LEBANON WES138.00 1	83	46.77	48.29	2%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	br3_merit_miso	4BONNIEVILLE138.00 TO 4MERE TVA 138.00 1	121	84.51	83.56	-1%	OPEN [4LEITCHFIELD138.00] [2LEITCHFIELD69.000] CKT 1
2030S	br3_merit_miso	4LEBANON WES138.00 TO 4LEBANON 138.00 1	83	39.00	40.44	1%	OPEN [4BONNIEVILLE138.00] [2BONNIV EK 69.000] CKT 1
2030S	br3_merit_miso	4SHREWSBURY 138.00 TO GI-2019-015P138.00 1 (4OHIO COUNTY138.00 TO 4SHREWSBURY 138.00)	210	169.30	167.00	-2%	OPEN [7DAVIESS 345.00] [7HARDIN CO 345.00] CKT 1
2030S	wilson_w	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	245	118.98	118.97	0%	OPEN [5LIVNGSTN CO161.00] [G2017-02 TP 161.00] CKT 1
2030S	mbr_nits	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	194	154.04	151.55	-2%	None
2030S	Base Dispatch	5EARLINGTN N161.00 TO 5N PRINCETON161.00 1	194	152.70	150.23	-2%	None
2030S	19-2_merit_miso	5LIVNGSTN CO161.00 TO G2017-02 TP 161.00 1	245	118.89	118.90	0%	OPEN [5EARLINGTN N161.00] [5N PRINCETON161.00] CKT 1

2. Description of Request

The request seeks to interconnect a 100 MW solar generator by connecting to the Black Branch-Hardinsburg 138kV line and then sink into the LG&E and KU system in merit order or sink as an energy resource. The request indicates that the generating plant will provide at the Point of Interconnection (POI) 100 MW. The solar plant was modeled with +/- 80 MVAR of reactive capability at the GI-2019-029 Generator in both the steady-state and stability analyses.

In order to obtain 100 MW injection at the POI, the study determined that the gross generation at the plant inverter bus would need to be 105.5 MW. The solar plant gross generation of 105.5 MW was modeled for this SIS. The data provided by the customer supports the 105.5 MW gross generation level.

The study determined that the inverters' +/- 80 MVAR reactive capability did meet the +/- 0.95 power factor at the high side of the customer main transformer requirement.

If the LGE-GIS-2019-029 request is granted, the new generation will have interconnection rights for 100 MW net output at the POI. The in-service date of the LGE-GIS-2019-029 request is 11/15/2022.

3. Study Criteria, Methodology, and Assumptions

3.1 Ad Hoc Study Group

An Ad Hoc Study Group was formed in accordance with the LG&E and KU GI Study Criteria document posted on the LG&E and KU OASIS. TranServ performed studies for this GI request and submitted a report for review to the Ad Hoc Study Group. Participation in the Ad Hoc Study Group was by invitation to all first tier Transmission Providers (TPs) and/or Transmission Owners (TOs) of LG&E and KU, i.e., MISO, PJM, Tennessee Valley Authority (TVA), TVA (RC), BREC, OMU, DUKE, VECTREN, AEP, OVEC, East Kentucky Power Cooperative (EKPC), and EEI/Department of Energy (DOE). Invitees whom indicated their interest in participating in the Ad Hoc Study Group by the date specified in the invitation and have a Critical Energy Infrastructure Information Non-Disclosure Agreement (CEII NDA) with LG&E and KU were allowed to participate in the Ad Hoc Study Group.

The purpose of forming an Ad Hoc Study Group and involving the other TOs is to meet the tariff requirement for third party coordination, to ensure that the study assumptions are valid and generally accepted; the study models are accurate; the study procedures are generally acceptable; and lastly, the impacts of the subject request on the transmission system have been appropriately addressed. This approach of forming an Ad Hoc Study Group is undertaken to gain regional acceptance of the study results.

TranServ managed the participation in the Ad Hoc Study Group so that the study could be completed in a timely manner. TranServ expected the Ad Hoc Study Group to respond to data and review requests as promptly as possible but certainly within five business days.

The Ad Hoc Group was requested to review and provide input to the following:

- Study Scope.
- Steady-state models, contingency files, and monitored element files (including flowgates).
- Stability models and disturbances.
- Study Report.

The LG&E and KU GI study criteria outlines three paths upon which it can be determined that an affected system study is required for an LG&E and KU GI request. Two of these paths require that the ITO identify a potential for an affected system study within an ITO analysis using ITO models as detailed in Section 3.2. The third path is for an Ad Hoc Study Group member to perform their own test.

Table 3-1 documents the Ad Hoc Study Group Comments which relate to independent testing performed by the Ad Hoc Study Group members consistent with the allowance for such testing in the LG&E and KU GI Criteria document.

Table 3-1
Ad Hoc Study Group Independent Study Comments

Ad Hoc Group Member	Date Received	Ad Hoc Group Member Comment provided within the 05/12/2021 Deadline
MISO	04/12/2021	MISO will perform Affected system study for LGE-GI-2019-029.
PJM	04/12/2021	PJM will need to perform an Affected system study for LGE-GI-2019-029.
No other Ad Hoc Member chose to provide independent testing results for this request by 05/12/2021 deadline.		

In addition to the Table 3-1 Ad Hoc Study Group responses received prior to the 05/21/2021 deadline, Table 3-1B documents additional responses received.

Table 3-1B
Additional Ad Hoc Study Group Comments

Ad Hoc Group Member	Date Received	Ad Hoc Group Member Comment provided after the 05/12/2021 Deadline
No other Ad Hoc Member chose to provide a response between 05/21/2021 and issuance of this report.		

3.2 Affected System Analysis Methodology

As indicated above, the LG&E and KU GI study criteria outlines three paths upon which it can be determined that an affected system study may be required for an LG&E and KU GI request. Two of these paths require that the ITO identify a potential for an affected system study within an ITO analysis using ITO models.

The first ITO determined path has two components.

- If the Point of Interconnection on the LG&E/KU Transmission System is within two buses of a neighboring system in the power flow model, the neighboring system is considered an Affected System.
- The second component involves an ITO affected system analysis using ITO models. For this component the ITO developed a neighboring system contingency list based on model branch sections using a 5% or greater PTDF on all neighboring BES facilities. The ITO then removed the neighboring system contingencies from the study P1 contingency file and added the newly

developed neighboring system contingency list to create an Affected System contingency file. Using the Affected System contingency file, neighboring TOs were identified if any as an Affected System if that system's post contingent transmission facility was loaded at more than 100% of the rate B in the ITO PSS/E models with a 20% or greater DF due to the study request.

The results of the first ITO determined path to a Potential Affected System Study are given in Tables 3-2 and 3-3.

Table 3-2
ITO Determined path to Affected System Study Results based on POI

Neighboring System Buses within Two Buses of the POI			Bus Owner Response
Bus Owner	**Bus Name**	**Bus Number**	
BREC (MISO member)	4N.HARD	340615	MISO will perform Affected system study for LGE-GI-2019-029.
EKPC (PJM member)	4CENT HARDIN	324568	PJM will need to perform an Affected system study for LGE-GI-2019-029.

As indicated in Table 3-2, both MISO and PJM will perform affected system studies.

Table 3-3
ITO Determined path to Affected System Study Results as per Affected System Analysis

Facility	Rating	Pre Project		Post Project		DF	Contingency
		MVA	%	MVA	%		
4N.HARD 138.00 TO 4HARDINSBURG138.00 1	191	163	85	234	122	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00]
2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	79	80	120	122	41%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00]
2KARGLE 69.000 TO 2ETOWN KU 69.000 1	98	79	80	101	103	22%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00]

The second ITO determined path to identify the potential need for an affected system study is through the ITO SIS steady state, stability and short circuit analyses. The results of these analyses are provided in Sections 4, 5 and 6 of this report respectfully.

In order for the ITO to perform the stability analysis, neighboring systems were given the opportunity to provide to the ITO the following within five business days after notification that the subject GI study scope was available:

- A list of faults to be analyzed including fault type (single to ground or three-phase), fault location, appropriate clearing times, switching sequence;

- Potentially affected system's damping criteria;
- Potentially affected system's channel files to be monitored;
- Potentially affected system's transient analysis voltage criteria and any other stability analysis criteria in addition to performance requirements of TPL-001-4

During the ITO's performance of the stability analysis, a neighboring TO would have been identified as a potentially affected system if constraints such as damping, transient voltage, or TPL-001-4 issues were identified on the neighbor's system. The ITO would have notified the neighboring TO through the Ad Hoc Process that they could be a potentially affected system.

The potentially affected system could then have required an affected system study to be performed that was entirely separate from the LG&E/KU SIS performed by the ITO. The ITO identified constraint on the potentially affected system would have been documented in the SIS report. The GIA would be contingent on mitigating the affected system constraints.

3.3 Computer Programs Used

The thermal and voltage analyses were performed using Siemens Power Technologies, Inc.'s (PTI's) Power System Simulator for Engineering (PSS/E®) Version 33 computer powerflow program and evaluation software. In addition, other programs were used to assist the engineers with processing and evaluating the system contingencies and special generation dispatch scenarios.

Power system analyses, utilizing PSS/E®, and ASPEN, were performed to determine whether the subject request's impact on the existing transmission system is within applicable limits in accordance with the study procedure as defined in the GI Study Criteria. The network analyses were used to predict both near-term and out-year monitored element performance. PSS/E® activity Alternative Current Contingency Calculation (ACCC) was used to determine system thermal and voltage performance with and without the subject request. Automated software consistent with the LG&E and KU planning process was used to run the ACCC activity for numerous dispatch scenarios. Dynamic simulations performed with PSS/E® software were used to determine the impact of the subject request on power system dynamic stability. A short circuit analysis utilizing ASPEN was performed to determine the subject request's impact on breaker duty levels.

3.4 Study Procedures

Power system analyses were performed to determine whether the subject request's impact on the transmission system is within applicable limits in accordance with the study procedure as defined in the LG&E and KU GI Study Criteria document. The network analyses results were used to predict monitored element performance. To facilitate the analysis, the 2023 Off Peak, 2023 Summer Peak and 2030 Summer Peak models were used.

This request was evaluated by comparing the equipment loading levels, voltage levels, and breaker duty levels of a Pre-LGE-GIS-2019-029 model to the equipment loading levels, voltage levels, and breaker duty levels of a Post-LGE-GIS-2019-029 model. Numerous dispatch scenarios were evaluated to determine system thermal and voltage performance with and without the subject request. The dispatch scenarios were analyzed in accordance with the LG&E and KU GI Study Criteria and Planning Guidelines.

3.5 Monitored Elements and Study Area

All study area elements as defined in Table 3-4 were monitored for the thermal and voltage analyses. GSUs were not monitored.

Table 3-4
Study Area

Owner	Area	Contingencies			Monitored Elements P1 and P3		Monitored Element P2 and P4	
		Explicitly Included	Broad All Singles/Ties Commands					
			kV min	kV max	kV min	kV max	kV min	kV max
EKPC	320	As submitted by EKPC to LG&E and KU for TEP	69	500	69	800	100	800
BREC	314	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
OVEC	206	As Submitted by PJM to LG&E and KU for TEP	69	500	100	800	100	800
DEI	208	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
LG&E and KU	363	As determined by LG&E and KU for use in TEP	69	500	69	800	100	800
OMU	364	As determined by LG&E and KU for use in TEP	69	500	69	800	100	800
TVA	347	As submitted by TVA to LG&E and KU for TEP			100	800	100	800
HE	207	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
SIGE	210	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
IPL	216	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
NIPS	217	As submitted by MISO to LG&E and KU for TEP			100	800	100	800
AEP	205	As Submitted by PJM to LG&E and KU for TEP			100	800	100	800
DEO&	212	As Submitted by PJM to LG&E and KU for TEP			100	800	100	800

3.6 Contingencies Considered

The simulations performed considered contingencies in Categories P0, P1, P2 (300 kV and above), P3, and P4 (300 kV and above) of the current effective versions of NERC TPL-001-4 standard and the LG&E and KU Transmission System Planning Guidelines. The same contingencies were analyzed for the Pre-GIS-2019-029 models and the Post-GIS-2019-029 models, to the extent practical.

For NERC Category P0, the system is intact (no contingencies). Generators off-line for economic reasons were not considered a contingency. In addition to the NERC Category P1 single element contingencies, multi-element NERC Category P1 through P4 contingencies were analyzed as directed by the Ad Hoc Study Group. Category P1 single contingencies included multi-element single contingencies, in the study area, initiated by a fault with normal clearing such as multi-terminal lines to the extent the Ad Hoc Study Group requested such contingencies and provided the necessary information.

Only the following Category P3 contingencies as identified in the LG&E and KU Transmission System Planning Guidelines were considered:

- An outage of one generator followed by another generator.
- An outage of one generator followed by one transmission circuit.
- An outage of one generator followed by one transmission transformer.

TranServ simulated the selected Category P3 contingencies as listed above when requested to do so by the Ad Hoc Study Group. For generation outages, the replacement generation required to offset the outage was simulated from the most restrictive of internal sources or a combination of internal sources and select external sources.

3.7 Dispatch Scenarios Considered

Several generation dispatch scenarios were evaluated. Appendix B shows the generation dispatch codes and the generation changes for each dispatch scenario. Each single dispatch was analyzed in combination with each study area contingency. Double dispatches were analyzed as one generator outage followed by another generator outage only.

3.8 Powerflow Model Development Details

3.8.1 Pre LGE-GIS-2019-029 Model Development

The following Pre GI models were developed for this study:

- 2023 Summer Peak Pre GI 2019-029 NRIS Model
- 2023 Summer Peak Pre GI 2019-029 ERIS Model
- 2023 Off Peak Pre GI 2019-029 NRIS Model
- 2023 Off Peak Pre GI 2019-029 ERIS Model
- 2030 Summer Peak Pre GI 2019-029 NRIS Model
- 2030 Summer Peak Pre GI 2019-029 ERIS Model

The Pre GI LGE-2019-029 models were created from the LG&E and KU 2021 Transmission Expansion Plan (TEP) Base Case Study (BCS) models which were provided to the ITO on 08/13/2020. The 08/13/2020 LG&E and KU 2021 TEP models were named 2021 BCS r20200812 by LG&E and KU and are referred to as the 2021 TEP BCS models throughout the remainder of this document. These models reflect the LSEs' August 2019 MOD-032 Load Forecast submittal. These models also reflect LG&E and KU's 2020 TEP Attachment 21 projects and project changes approved prior to 08/10/2020. Additional approved changes to projects were included in the GI-2019-029 Models as shown in Table 3-5.

Table 3-5
ITO Approved TEP Project Changes

Project Number	Original Project	Modification
992 1003	Construct a new 69 kV line from Lebanon to Lebanon South and a ring bus at Lebanon South. Move the Lebanon Industrial and Lebanon East Loads to the new line.	Construct a new 69 kV line from Lebanon to a point just south of EKPC's Lebanon station. Move the Lebanon Industrial and Lebanon East Loads to the new line. The new line will be operated with a motor operated normally open switch between Lebanon East and the new tap point.
952	Install a second West Lexington 450 MVA, 345/138 kV transformer and necessary 345 kV breakers to create a four breaker 345 kV ring bus configured such that the two transformers do not share a single breaker. Reconfigure the Brown N to West Lexington and Ghent to W Lexington 345 kV lines as necessary.	1164: Install a second 345/138kV transformer at Brown North. 830: Install a 138kV, 60 MVAr capacitor at West Lexington.
975	Conductor replacement of 2.80 miles of 392.5 MCM 24X13 ACAR conductor in the Upper Mill Creek to Riverport 69 kV line section, using 397.5 MCM 26X7 ACSR or better conductor.	Some of the load currently served at Terry #2 will be shifted to International and Pleasure Ridge 138 kV.
1117	Conductor replacement of the 1.2 miles of 392.5 ACAR in the Terry to Riverport 69 kV line with 397.5 ACSR.	Some of the load currently served at Terry #2 will be shifted to International and Pleasure Ridge 138 kV.
1109	Reset/replace the 161 kV bushing CT associated with the Farley 161/69 kV transformer to at least 600 amps.	Project cancelled.

As shown in Table 3-6, some rating updates were applied to the Pre GI-2019-029 models.

Table 3-6
Rating Updates Applied to All GI-2019-029 Models

From Bus Name	From Bus Number	To Bus Name	To Bus Number	Circuit ID	Season	Updated Rate A	2021 TEP Rate A	Updated Rate B	2021 TEP Rate B
2VINE STREET69.000	324984	2WEST HIGH 69.000	324988	1	Off-Peak	77.2	90	85	92
2RACE STREET69.000	324934	2VINE STREET69.000	324984	1	Off-Peak	69	69	81	69
2RACE STREET69.000	324934	2VINE STREET69.000	324984	1	Summer	69	55	81	69
5CALVERT KY 161.00	360125	5LIVNGSTN CO161.00	324151	1	Off-Peak	335	328	335	328
5CALVERT KY 161.00	360125	5LIVNGSTN CO161.00	324151	1	Summer	265	265	314	299

The 2021 TEP BCS Model series includes only 2022, 2029 and 2030 models. The 2023 Summer Peak GI 2019-029 Model was derived from the 2022 summer 2021 TEP BCS Model and 2023 Off Peak GI 2019-029 Model was derived from the 2022 Off Peak 2021 TEP BCS Model. The 2022 summer 2021 TEP BCS Model was modified to include 2023 summer loads and the Table 3-7 projects which are expected to be placed in-service between June 2022 and May 2023. The 2022 Off Peak 2021 TEP BCS Model was modified to include 2023 Off Peak loads and the Table 3-8 projects which are expected to be placed in-service between February 2022 and February 2023.

Table 3-7
Projects to be added to the 2022 Summer 2021 TEP Model to form the 2023 Summer

Project Number	2020 TEP Description	Estimated Timetable for Implementation
385	Install a 69 kV, 16.2 MVAR capacitor bank at Warsaw East 69 kV.	11/30/2022
664	Replace the Artemus 161/69 kV, 56 MVA transformer with a 90 MVA transformer.	11/30/2022
803	Increase the maximum operating temperature of the 556.5 MXM 26X7 ACSR conductor (3.51 miles) in the Barbourville -Bimble 69 kV section of the Artemus - Bimble 69 kV line from 135F to 150F. Increase the MOT of the 266.8 MCM 26X7 ACSR (0.20 miles) in the same line section form 155F to 212FF.	05/30/2023
847	Install a 13.5 MVAR, 69 kV capacitor bank at or near the delivery point for EKPC's West Mount Washington load on the Bullitt County 69 kV loop south of Louisville.	05/30/2023
1098	Replace breaker 178-714 at Hardin County in conjunction with project 180 to install a second 345/138 kV transformer at Hardin County. The breaker must have an interrupting rating of at least 40 kA.	05/30/2023

Table 3-8
Projects to be added to the 2022 Off Peak 2021 TEP Model to form the 2023 Off Peak

Project Number	2020 TEP Description	Estimated Timetable for Implementation
178	Install a second 138/69 kV, 185 MVA transformer at Hardin County.	05/30/2022
180	Install a second 345-138 kV, 450 MVA transformer at Hardin County.	05/30/2022
329	Replace 138kV terminal equipment rated less than or equal to 1281 Amps (306 MVA) summer emergency rating at Watterson associated with the Watterson to Jefferson Tap 138kV line with equipment capable of a minimum of 1428 Amps (341 MVA) summer emergency rating.	05/30/2022
958	Construct new Elizabethtown to Hardin Co 69 kV #2 using 1272 MCM ACSR 26X7 conductor.	05/30/2022
1107	Increase the maximum operating temperature of 1.96 miles of 397.5 ACSR in the Shelbyville South to Shelby Co tap section of the Shelbyville to Bardstown 69 kV line from 150°F to a minimum of 160°F.	05/30/2022
1122	Replace breaker 043-618 on the 69 kV side of the Lebanon 138/69 kV transformer #2.	05/30/2022
385	Install a 69 kV, 16.2 MVAR capacitor bank at Warsaw East 69 kV.	11/30/2022
664	Replace the Artemus 161/69 kV, 56 MVA transformer with a 90 MVA transformer.	11/30/2022

As appropriate, all long-term firm network TSRs which were confirmed at the time of the 2021 TEP SPM build were included in the 2021 TEP BCS power flow models. Additional TSRs have been confirmed and those TSRs will be included in the GI-2019-029 models. The TSRs which will be added to the 2021 TEP BCS models to create the Pre GI LGE-2019-029 models are listed in Table 3-9.

Table 3-9
Confirmed TSRs added to the 2021 TEP BCS models to form the Pre GI-2019-029 Models

NITS on OASIS Number	SIS	MW	Type
88965179	2019-004	7.5	ADD NITS DNR
89475755	2019-007	28	ADD NITS LOAD
90030484	2019-009	-13	Terminate NITS DNR
90030485	2019-009	13	ADD NITS DNR
90089795	2019-010	11	MODIFY NITS LOAD
90089812	2019-010	11	MODIFY NITS LOAD
90089821	2019-010	-11	MODIFY NITS LOAD
90089823	2019-010	-11	MODIFY NITS LOAD
90221160	2019-011	15	MODIFY NITS LOAD
90401751	2019-012	17	MODIFY NITS LOAD
93013630 93013653	2021-001		MODIFY NITS LOAD
93014409	2021-002	15	ADD NITS DNR

All LG&E and KU prior queued generators were included in the Pre GI-2019-029 power flow models. All LG&E and KU prior queued generators were added to the 2021 TEP BCS models to form the Pre GI-2019-029 models are shown in Table 3-10.

Table 3-10
Prior Queued generators added to the 2021 TEP BCS models to form the Pre GI-2019-029 models

Queue Position	Queue Date	County	State	Max Output (MW) S/W	Point of Inter-connection	In-Service Date	Inter-connection Service Type
LGE-GIS-2017-002	03/01/2017	Lyon	KY	86/86	North Princeton-Livingston County 161 kV	12/01/2022	NRIS
LGE-GIS-2017-003	04/27/2017	Harrison	KY	35/35	Cynthiana EK Tap - Millersburg 69 kV	06/01/2021	NRIS/ERIS
LGE-GIS-2019-001	01/15/2019	Washington	KY	110/110	Lebanon-Danville Tap 138 kV Line	12/01/2023	NRIS/ERIS
LGE-GIS-2019-002	02/06/2019	Ballard	KY	104/104	Grahamville-Wickliffe 161 kV Line	06/01/2023	NRIS/ERIS
LGE-GIS-2019-003	02/07/2019	Meade	KY	121/121	Cloverport-Tip Top 138 kV Line	12/01/2022	NRIS/ERIS
LGE-GIS-2019-004	02/07/2019	Breckinridge	KY	200/200	Hardinsburg 138 kV Substation	12/01/2022	NRIS/ERIS
LGE-GIS-2019-008	03/22/2019	Caldwell	KY	100/100	North Princeton 161 kV Substation	12/31/2021	NRIS/ERIS
LGE-GIS-2019-015	03/22/2019	Grayson	KY	100/100	Ohio County to Shrewsbury 138 kV	12/31/2021	NRIS/ERIS
LGE-GIS-2019-020	03/22/2019	Hopkins	KY	85/85	Corydon Tap to Green River 161 kV	12/31/2021	NRIS/ERIS
LGE-GIS-2019-023	03/29/2019	Lyon & Caldwell	KY	150	Livingston Co. to North Princeton 161 kV line	12/15/2021	NRIS/ERIS
LGE-GIS-2019-025	05/02/2019	Mercer	KY	98.42	Bardstown-Brown CT 138 kV line	12/01/2022	NRIS/ERIS

As per the LG&E and KU Generation interconnection Study Criteria document no winter models were studied and all solar generation within Area 363, exclusive of the request under study, were modeled at 80% in the summer models.

Non-solar generation in the vicinity of the Point of Interconnection (POI) of the subject request were maximized in the Pre GI 2019-029 models to the extent possible within the area in which they are connected. The specific generators that were maximized are given in Table 3-11.

Table 3-11
2021 TEP BCS modeling of Generation in the vicinity of the GI 2019-029 POI maximized as allowed within their modeled areas in the GI-2019-029 Models

Bus Number	Bus Name	ID	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	422.5	422.5	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	465	521	526	526	526	526
325093	1CANERUN7CT118.00	71	LGEE	234.5	234.5	231.5	231.5	231.5	231.5
325094	1CANERUN7CT218.00	72	LGEE	234.5	234.5	231.5	231.5	231.5	231.5
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
253625	10CAN_G1 6.9000	1	SIGE	8.74	30	8.74	30	8.74	30
253626	10CAN_G2 6.9000	2	SIGE	8.74	30	8.74	30	8.74	30
253627	10CAN_G3 6.9000	3	SIGE	8.74	30	8.74	30	8.74	30

The following Ad Hoc Study Group changes were modelled as appropriate:

- Addition of Area 314 200 MW load
- Addition of MISO queued requests J753 (100MW) and J762 (200MW)

3.8.2 Post LGE-GIS-2019-029 Model Development

The following Post LGE-GIS-2019-029 models were developed for this study:

- 2023 Summer Peak Post GI 2019-029 NRIS Model
- 2023 Summer Peak Post GI 2019-029 ERIS Model
- 2023 Off Peak Post GI 2019-029 NRIS Model
- 2023 Off Peak Post GI 2019-029 ERIS Model
- 2030 Summer Peak Post GI 2019-029 NRIS Model
- 2030 Summer Peak Post GI 2019-029 ERIS Model

The Pre GI-2019-029 NRIS Models were modified to include the GI-2019-029 Solar generation, sinking into the LG&E and KU generation fleet in merit order to form the Post GI-2019-029 NRIS Models. The Pre GI-2019-029 ERIS Models were modified to include the GI-2019-029 Solar generation, sinking based on scaling the generation of the local Balancing Authorities to the north, south, east, and west of the LG&E and KU control area each by 25% of the request to form the Post GI-2019-029 ERIS Models.

Before the start of the study, the preliminary Pre and Post LGE GIS-2019-029 models were sent to the Ad Hoc Study Group for review. The models were updated to incorporate any modeling adjustments indicated by the Ad Hoc Study Group as appropriate.

3.9 Network Analysis Criteria

A Network Analysis was performed to determine the impact of the subject request on all Study Area system intact and post-contingent branch loadings and bus voltages. This analysis was performed in accordance with criteria and methodology given in the LG&E and KU GI Study Criteria and the LG&E and KU Planning Guidelines. The Study Area is defined in Section 3.4 of this report. If provided by the Ad Hoc Study Group, criteria specific to a facility owner was used to evaluate facilities not owned by LG&E and KU. If no criteria information was provided by the Ad Hoc Study Group for a particular TO, the criteria and methodology given in the LG&E and KU GI Study Criteria was assumed to apply.

3.10 Reliability Margins for LG&E and KU Flowgates

Requests for Capacity Benefit Margin (CBM) set-aside that go beyond the 18 month ATC calculation horizon were accounted for by developing additional generation scenarios that mimic the requesting entities original request which must include the assumed sources of the CBM. No requests for CBM that go beyond the 18 month ATC calculation horizon have been received. So no LKE CBM analysis was performed for this study.

Transmission Reliability Margin (TRM) outside of the 18 month ATC calculation horizon were accounted for by the generation replacement scenarios that include both internal and CRSG partner sources for the replacement generation.

3.11 Flowgate Analysis

A Non-LG&E and KU flowgate analysis was performed to determine if sufficient Available Flowgate Capability (AFC) would exist on regional Non- LG&E and KU flowgates with the addition of the subject request. An impact analysis on Reciprocally Coordinated Flowgates (RCF) was performed to determine if the subject request significantly impacts those posted flowgates in accordance with the LG&E and KU GI Study Criteria posted on the LG&E and KU OASIS.

There are two types of flowgates, Power Transfer Distribution Factor (PTDF) flowgates and Outage Transfer Distribution Factor (OTDF) flowgates. A PTDF flowgate monitors a system intact condition and an OTDF flowgate monitors a contingency condition. If the loading on any Non-LG&E and KU flowgates exceed the PTDF and OTDF thresholds of 5% and 20% respectively and the flowgate ratings the results will be listed in the report and provided to the flowgate owner to determine if they are constraints to granting the request.

4. Powerflow Analysis Results

4.1 Contingency Analysis

Contingency analyses were performed using models, criteria, and methodology described in Section 3. The incremental impact of the LGE-GIS-2019-029 request was evaluated by comparing flows and voltages with and without the requested interconnection. Analyses were performed using Siemen's PSS/E® and programs to assist engineers with processing and evaluating the system contingencies and special generation dispatch scenarios.

It is also important to note that not all contingencies considered resulted in a convergent powerflow solution. Most initially divergent contingencies converged when other solution techniques some of which included locking switched shunts were applied. If potential constraints were identified through a shunts locked solution, further analysis was performed to obtain a powerflow solution with shunts enabled. Only the results obtained through a shunts enabled powerflow solution were considered as valid results. The contingencies that were divergent in both the initial shunts enabled and shunt locked solution attempts were solved using other solution techniques. Appendix C lists those solution techniques which required model modifications.

4.1.1 NRIS Analysis

The GI 2019-029 NRIS 2023 Off Peak, 2023 Summer Peak, and 2030 Summer Peak LG&E and KU thermal constraints due to the subject request are given in Tables 4-1. These constraints were found for many dispatch/contingency combinations in the NRIS Analyses. Only the result with the highest post project loading for each facility is shown in Table 4-1.

Table 4-1
GI 2019-029 NRIS LG&E and KU Thermal Constraints

Model	Dispatch	Facility	Rating	Pre Project	Post Project		DF	Contingency
				MVA	MVA	%		
2023OP NRIS	mgh_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	98	63.84	104.24	106.37	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	170.44	241.04	126.20	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	60.37	98.31	114.31	38%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO 4CENT HARDIN138.00 1	227	149.07	227.05	100.02	78%	None
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	161.87	241.71	116.21	80%	None
2023S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160.20	239.80	115.29	80%	None
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	149.11	217.91	114.09	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	59.49	97.52	113.40	38%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	159.88	241.58	116.14	82%	None
2030S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	158.00	239.57	115.18	82%	None
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	150.11	218.66	114.48	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

The GI 2019-029 NRIS 2023 Off Peak, 2023 Summer Peak, and 2030 Summer Peak third party thermal constraints due to the subject request are given in Table 4-2. These constraints were found for many dispatch/contingency combinations in the NRIS Analyses. Only the result with the highest post project loading for each facility is shown in Table 4-2.

Table 4-2
GI 2019-029 NRIS Third Party Thermal Constraints

Model	Dispatch	Facility	Owner	Rating	Pre Project		Post Project		Contingency
					MVA	%	MVA	%	
2023OP NRIS	mtc_nits	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	82	83%	123	125%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	mtc_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	98	64	65%	104	106%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	170	89%	241	126%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	77	78%	116	119%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	60	70%	98	114%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	149	78%	218	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	76	78%	116	118%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	59	69%	98	113%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	150	79%	219	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

The EKPC owned third party constraints will be further investigated in the PJM affected system study. The BREC owned third party constraints will be further investigated in the MISO affected system study.

No Off Peak or Summer NRIS, system intact or contingency, voltage constraints due to the subject request were found.

4.1.2 NRIS Analysis Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

After completion of the GI-2019-029 NRIS analysis but prior to the issuance of this report, the GI-2019-020 and GI-2019-023 customers notified the ITO of withdrawal of the GI-2019-020 and GI-2019-023 requests from the LG&E and KU GI queue. The ITO subsequently performed a sensitivity analysis of the impact of these withdrawals on the GI-2019-029 NRIS LG&E and KU Table 4-1 constraints. The results of that analysis are provided in Table 4-3.

Table 4-3
LG&E and KU NRIS Constraints Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

Model	Dispatch	Facility	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
				MVA	%	MVA	%	MVA	%	
2023OP NRIS	mtc_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	98	64	65%	104	106%	100	102%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	170	89%	241	126%	241	126%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	60	70%	98	114%	95	110%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	149	78%	218	114%	219	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	mtc_nits	**4BLACKBRANCH138.00 TO 4CENT HARDIN138.00 1**	227	149	66%	227.05	100.02%	223	**98%**	None
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	162	78%	242	116%	238	114%	None
2023S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160	77%	236	114%	236	114%	None
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	59	69%	98	113%	94	109%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	150	79%	219	114%	219	115%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160	77%	242	116%	238	114%	None
2030S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	158	76%	236	113%	236	113%	None

As can be seen from Table 4-3, with withdrawal of the GI-2019-020 and GI-2019-023 requests, the Black Branch – Central Hardinsburg 138 kV line was not found to overload in the 2023 Summer NRIS limited sensitivity analysis. The Black Branch – Central Hardinsburg 138 kV line was not found as constraint in the limited sensitivity 2030 Summer NRIS analysis. Based on the results in Table 4-3, it is expected that the Elizabethtown – Kargle 69 kV line, the Hardinsburg – New Hardinsburg 138 kV line, and the Black Branch – GI-2019-

029 POI 138 kV line would continue to be identified as constraints in the NRIS analysis even with the withdrawal of the GI-2019-020 and GI-2019-023 requests.

After completion of the GI-2019-029 NRIS analysis but prior to the issuance of this report, the GI-2019-020 and GI-2019-023 customers notified the ITO of withdrawal of the GI-2019-020 and GI-2019-023 requests from the LG&E and KU GI queue. The ITO subsequently performed a sensitivity analysis of the impact of these withdrawals on the GI-2019-029 NRIS third party Table 4-2 constraints. The results of that analysis are provided in Table 4-4.

Table 4-4
Third Party NRIS Constraints Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

Model	Dispatch	Facility	Owner	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
					MVA	%	MVA	%	MVA	%	
2023OP NRIS	mtc_nits	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	82	83%	123	125%	118	121%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	mtc_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	98	64	65%	104	106%	100	102%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	170	89%	241	126%	241	126%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	77	78%	116	119%	113	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	60	70%	98	114%	95	110%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	149	78%	218	114%	219	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	76	78%	116	118%	112	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	59	69%	98	113%	94	109%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	150	79%	219	114%	219	115%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

As can be seen from Table 4-4, with withdrawal of the GI-2019-020 and GI-2019-023 requests, the Hardinsburg – New Hardinsburg 138 kV, the Central Hardinsburg – Kargle 69 kV line and the Elizabethtown – Kargle 69 kV line were found to overload.

Based on the results in Tables 4-3 and 4-4, it is expected that the Elizabethtown – Kargle 69 kV line, the Hardinsburg – New Hardinsburg 138 kV line, the Black Branch – GI-2019-029 POI 138 kV line, and the Central Hardinsburg – Kargle 69 kV line would continue to be identified as constraints in the NRIS analysis even with the withdrawal of the GI-2019-020 and GI-2019-023 requests.

The EKPC owned third party constraints will be further investigated in the PJM affected system study. The BREC owned third party constraints will be further investigated in the MISO affected system study.

4.1.3 ERIS Analysis

The GI 2019-029 ERIS 2023 Off Peak, 2023 Summer Peak, and 2030 Summer Peak LG&E and KU thermal constraints due to the subject request are given in Table 4-5. These constraints were found for many dispatch/contingency combinations in the ERIS Analyses. Only the result with the highest post project loading for each facility is shown in Table 4-5.

Table 4-5
GI 2019-029 ERIS LG&E and KU Thermal Constraints

Model	Dispatch	Facility	Rating	Pre Project	Post Project		DF	Contingency
				MVA	MVA	%		
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	172.35	243.16	127.31	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	54.96	92.21	107.22	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	155.13	234.01	112.50	79%	None
2023S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	154.00	232.87	111.96	79%	None
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	147.72	216.73	113.47	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	53.51	90.81	105.59	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152.61	233.02	112.03	80%	None
2030S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152.00	232.01	111.54	80%	None
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148.47	217.30	113.77	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

The GI 2019-029 ERIS 2023 Off Peak, 2023 Summer Peak, and 2030 Summer Peak third party thermal constraints due to the subject request are given in Table 4-6. These constraints were found for many dispatch/contingency combinations in the ERIS Analyses. Only the result with the highest post project loading for each facility is shown in Table 4-6.

Table 4-6
GI 2019-029 ERIS Third Party Thermal Constraints

Model	Dispatch	Facility	Owner	Rating	Pre Project	Post Project		DF	Contingency
					MVA	MVA	%		
2023OP ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	75.05	115.25	117.60	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	172.35	243.16	127.31	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	71.22	110.30	112.55	39%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	54.96	92.21	107.22	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	147.72	216.73	113.47	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	70.05	109.30	111.53	39%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	53.51	90.81	105.59	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	148.47	217.30	113.77	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

The EKPC owned third party constraints will be further investigated in the PJM affected system study. The BREC owned third party constraints will be further investigated in the MISO affected system study.

No Off Peak or Summer ERIS, system intact or contingency, voltage constraints due to the subject request were found.

4.1.4 ERIS Analysis Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

After completion of the GI-2019-029 ERIS analysis but prior to the issuance of this report, the GI-2019-020 and GI-2019-023 customers notified the ITO of withdrawal of the GI-2019-020 and GI-2019-023 requests from the LG&E and KU GI queue. The ITO subsequently performed a sensitivity analysis of the impact of these withdrawals on the GI-2019-029 ERIS LG&E and KU Table 4-5 constraints. The results of that analysis are provided in Table 4-7

Table 4-7
LG&E and KU ERIS Constraints Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

Model	Dispatch	Facility	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
				MVA	%	MVA	%	MVA	%	
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	172	90%	243	127%	243	127%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	55	64%	92	107%	90	104%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148	77%	217	113%	217	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	155	75%	234	113%	231	111%	None
2023S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	154	74%	230	111%	230	111%	None
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	54	62%	91	106%	88	103%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148	78%	217	114%	218	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	153	73%	233	112%	230	111%	None
2030S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152	73%	229	110%	229	110%	None

As can be seen from Table 4-7, with withdrawal of the GI-2019-020 and GI-2019-023 requests, the Hardinsburg – New Hardinsburg 138 kV line, the Elizabethtown – Kargle 69 kV line, and the Black Branch – GI-2019-029 POI 138 kV line were found to overload.

After completion of the GI-2019-029 ERIS analysis but prior to the issuance of this report, the GI-2019-020 and GI-2019-023 customers notified the ITO of withdrawal of the GI-2019-020 and GI-2019-023 requests from the LG&E and KU GI queue. The ITO subsequently performed a sensitivity analysis of the impact of these withdrawals on the GI-2019-029 ERIS third party Table 4-6 constraints. The results of that analysis are provided in Table 4-8.

Table 4-8
Third Party ERIS Constraints Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

Model	Dispatch	Facility	Owner	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
					MVA	%	MVA	%	MVA	%	
2023OP ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	75	77%	115	118%	113	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	172	90%	243	127%	243	127%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	71	73%	110	113%	108	110%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	55	64%	92	107%	90	104%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	148	77%	217	113%	217	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	EKPC	98	70	71%	109	112%	107	109%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	EKPC	86	54	62%	91	106%	88	103%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	BREC	191	148	78%	217	114%	218	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

As can be seen from Table 4-8, with withdrawal of the GI-2019-020 and GI-2019-023 requests, the Hardinsburg – New Hardinsburg 138 kV line, the Central Hardinsburg – Kargle 69 kV line and the Elizabethtown – Kargle 69 kV line were found to overload.

The EKPC owned third party constraints will be further investigated in the PJM affected system study. The BREC owned third party constraints will be further investigated in the MISO affected system study.

Based on Tables 4-7 and 4-8, it is expected that the Hardinsburg – New Hardinsburg 138 kV line, the Elizabethtown – Kargle 69 kV line, the Black Branch – GI-2019-029 POI 138 kV line, and the Central Hardinsburg – Kargle 69 kV line would continue to be identified as constraints in the ERIS analysis even with the withdrawal of the GI-2019-020 and GI-2019-023 requests.

4.2 Non-LG&E and KU Flowgate Analysis

As per the LG&E and KU GI Study Criteria document, the flowgate analysis is limited to the NRIS request. Reciprocally coordinated Non-LG&E and KU constrained interface analyses were performed using models, criteria, and methodology described in Section 3. The incremental impact was evaluated by comparing interface MW flows with and without the subject request. The LG&E and KU GI Study Criteria Document states “a flowgate analysis will not be performed for ERIS requests”. Thus, the GI-2019-029 flowgate analysis was limited to the NRIS scenario. All Non-LG&E and KU flowgates which were found in excess of the 20% OTDF or 5% PTDF impact criterion are listed in this Section. A complete listing of all reciprocally coordinated Non-LG&E and KU constrained interface results is given in Appendix D.

No flowgates with an impact, due to the subject request, greater than the 5% or 20% DF minimum threshold criteria were found.

4.3 Conclusion

4.3.1 NRIS Steady State Results Conclusion

LG&E and KU ERIS thermal constraints as shown in Table 4-1 were identified. Based on the limited sensitivity to the withdrawal of the GI-2019-020 and GI-2019-023 requests, LG&E and KU NRIS thermal constraints as shown in Table 4-3 were identified. Third party NRIS thermal constraints as shown in Table 4-2 were identified. Based on the limited sensitivity to the withdrawal of the GI-2019-020 and GI-2019-023 requests, third party NRIS thermal constraints as shown in Table 4-4 were identified. No voltage or flowgate constraints due to the subject request were identified.

4.3.2 ERIS Steady State Results Conclusion

LG&E and KU ERIS thermal constraints as shown in Table 4-5 were identified. Based on the limited sensitivity to the withdrawal of the GI-2019-020 and GI-2019-023 requests, LG&E and KU ERIS thermal constraints as shown in Table 4-7 were identified. Third party ERIS thermal constraints as shown in Table 4-6 were identified. Based on the limited sensitivity to the withdrawal of the GI-2019-020 and GI-2019-023 requests, third party ERIS thermal constraints as shown in Table 4-8 were identified. No voltage or flowgate constraints due to the subject request were identified.

5. Stability Analysis

5.1 Introduction

As defined in the LG&E and KU GI Study Criteria posted on the LG&E and KU OASIS, a stability analysis was performed to evaluate the impact of the new generation on the transient stability of the existing power system under various disturbance conditions. The stability analysis was performed for both near term and out year summer peak, summer generation maximization, and light load system conditions with appropriate earlier queued generators included in the model. The stability models emulated the steady-state modeling as closely as practical and appropriate. The disturbances were defined by TranServ and reviewed by the Ad Hoc Study Group.

5.2 Model Development

5.2.1 Pre GI-2019-029 Stability Models

The following Pre GI-2019-029 stability models were developed for the LG&E and KU GI-2019-029 SIS Stability Analysis:

- 2021 Summer Peak Pre GI 2019-029 Model
- 2021 Summer Maximized Pre GI 2019-029 Model
- 2024 Light Load Pre GI 2019-029 Model
- 2029 Summer Peak Pre GI 2019-029 Model

The pre LGE-GIS-2019-029 models listed above were created from 2020 TEP 2021S, 2021S Max, 2024LL and 2029S stability models. The TSR and prior queued GI request modeling was as close to the Steady-State modeling as appropriate. All LG&E and KU prior queued generators with completed SISs were added to the 2020 TEP models to form the Pre GI-2019-029 models as shown in Table 5-1.

Table 5-1
Prior Queued generators added to the 2020 TEP models to form the Pre GI-2019-029 Stability Models

Queue Position	Queue Date	County	State	Max Output (MW) S/W	Point of Inter-connection	In-Service Date	Inter-connection Service Type
LGE-GIS-2017-002	03/01/2017	Lyon	KY	86/86	North Princeton-Livingston County 161 kV	12/01/2022	NRIS
LGE-GIS-2017-003	04/27/2017	Harrison	KY	35/35	Cynthiana EK Tap - Millersburg 69 kV	06/01/2021	NRIS/ERIS
*LGE-GIS-2019-001	01/15/2019	Washington	KY	110/110	Lebanon-Danville Tap 138 kV Line	12/01/2023	NRIS/ERIS
LGE-GIS-2019-002	02/06/2019	Ballard	KY	104/104	Grahamville-Wickliffe 161 kV Line	06/01/2023	NRIS/ERIS
LGE-GIS-2019-003	02/07/2019	Meade	KY	121/121	Cloverport-Tip Top 138 kV Line	12/01/2022	NRIS/ERIS
LGE-GIS-2019-004	02/07/2019	Breckinridge	KY	200/200	Hardinsburg 138 kV Substation	12/01/2022	NRIS/ERIS
LGE-GIS-2019-008	03/22/2019	Caldwell	KY	100/100	North Princeton 161 kV Substation	12/31/2021	NRIS/ERIS
LGE-GIS-2019-015	03/22/2019	Grayson	KY	100/100	Ohio County to Shrewsbury 138 kV	12/31/2021	NRIS/ERIS
LGE-GIS-2019-020	03/22/2019	Hopkins	KY	85/85	Corydon Tap to Green River 161 kV	12/31/2021	NRIS/ERIS
LGE-GIS-2019-023	03/29/2019	Lyon	KY	150	Livingston Co. to North Princeton 161 kV line	12/15/2021	NRIS/ERIS
LGE-GIS-2019-025	05/02/2019	Mercer	KY	98.42	Bardstown-Brown CT 138 kV line	12/01/2022	NRIS/ERIS

* This request was not added in the 2021S Stability Model because of a later in-service date

As per the LG&E and KU Generation interconnection Study Criteria document all solar generation within Area 363, exclusive of the request under study, was modeled at 80% in the summer models.

Non - Solar Generation in the vicinity of the Point of Interconnection (POI) of the subject request was maximized in the Pre GI 2019-029 stability models to the extent possible within the area in which they are connected. The specific generators which were maximized are given in Table 5-2.

Table 5-2
2020 TEP modeling of Generation in the vicinity of the GI-2019-029 POI which were maximized as allowed within their modeled areas in the GI-2019-029 Models

Bus Name	ID	Area	2021S Pgen	2021S Pmax	2021S Max Pgen	2021S Max Pmax	2024LL Pgen	2024LL Pmax	2029S Pgen	2029S Pmax
1MILL CRK 1 22.000	1	LGEE	327	327	343	343	123	327	327	327
1MILL CRK 2 22.000	2	LGEE	331	331	341	341	0	331	331	331
1MILL CRK 3 22.000	3	LGEE	422	422	444	444	300	422	422	422
1MILL CRK 4 22.000	4	LGEE	514	514	541	541	0	514	514	514
1CANERUN7CT118.00	71	LGEE	204	204	230	230	204	204	204	204
1CANERUN7CT218.00	72	LGEE	204	204	230	230	204	204	204	204
1CANERUN7ST 18.000	7S	LGEE	231	231	231	231	231	231	231	231
10CAN_G1 6.9000	1	SIGE	30	30	30	30	30	30	30	30
10CAN_G2 6.9000	2	SIGE	30	30	30	30	30	30	30	30
10CAN_G3 6.9000	3	SIGE	30	30	30	30	30	30	30	30

5.2.2 Post GI-2019-029 Stability Models

The following Post LGE-GIS 2019-029 stability models were developed for this study:

- 2021 Summer Peak Post GI 2019-029 Model
- 2021 Summer Maximized Post GI 2019-029 Model
- 2024 Light Load Post GI 2019-029 Model
- 2029 Summer Peak Post GI 2019-029 Model

The Pre GI-2019-029 Models were modified to include the GI-2019-029 Solar generation, sinking based on scaling the generation of the local Balancing Authorities to the north, south, east and west of the LG&E and KU control area each by 25% of the request to form the Post GI-2019-029 Stability Models. Preliminary GI-2019-029 stability models were sent to the Ad Hoc Study Group for review.

Specifically the following areas were used:

- North – Area 600 XCEL.
- South – Area 346 SOCO.
- East – Area 342 DUKE.
- West – Area 330 AECI.

If modeling adjustments were indicated by the Ad Hoc Study Group, the models were updated to incorporate those adjustments as appropriate.

5.3 Disturbance Definitions

The transient stability impacts of GI-2019-029 were evaluated for all selected disturbances. The selected disturbances were defined by TranServ, and reviewed by the Ad Hoc Study Group. The definitions of all disturbances evaluated are listed in Tables 5-3 through 5-10.

Table 5-7 lists the P4 disturbances which were initially screened using the same screening technique applied by LG&E and KU in the 2020 TEP, on 2021S Max model applying a SLG fault for 1 second. No criteria violations were observed for any of these disturbances and thus these disturbances were not chosen for analysis in this study.

Table 5-8 lists the P4.5 and P5.5 disturbances which was initially screened using the same screening technique applied by LG&E and KU in the 2021 TEP, on 2021S Max model by applying a SLG fault for a long clearing time of 60 cycles. No criteria violations were observed for these disturbances and thus none were chosen for analysis in this study.

Table 5-3
GI-2019-029 Category P1 Disturbances

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name	Reclosing Time (Cycles)	Final Clearing Time (Cycles)
342568	138	3PH	6	4CENT HARDIN138 -4HARDIN CO138 Line	26	32
342568	138	3PH	6	4CENT HARDIN138-69kV XFMR		
324261	138	3PH	6	4HARDIN CO138 -4ROGERSVILLE138 Line	26	32
324261	138	3PH	6	4HARDIN CO138 -4CENT HARDIN138 Line	26	32
324261	138	3PH	6	4HARDIN CO138 -4ETOWN138 Line	26	32
324261	138	3PH	6	4HARDIN CO138 -2HARDIN CO 69 XFMR1		
324261	138	3PH	6	4HARDIN CO138 -2HARDIN CO 69 XFMR2		
324261	138	3PH	6	4HARDIN CO138 -7HARDIN CO345 XFMR1		
324261	138	3PH	6	4HARDIN CO138 -7HARDIN CO345 XFMR2		
324106	345	3PH	6	7HARDIN CO345- 4HARDIN CO138 XFMR2		
324106	345	3PH	6	7HARDIN CO345- 4HARDIN CO138 XFMR1		
324106	345	3PH	6	7HARDIN CO345 -7MILL CREEK345/OTTERCRK via RedmondRd	26	32
324106	345	3PH	6	7HARDIN CO345 -7BROWN NORTH345 Line	26	32
324106	345	3PH	6	7HARDIN CO345 -7DAVIESS345 Line	26	32
324260	138	3PH	6	Hardinsburg-Central Hardin138kV line	26	32
324260	138	3PH	6	4HARDINSBURG138 -4N.HARD138 Line	26	32
324260	138	3PH	6	4HARDINSBURG138 -4CLOVERPORT138 Line	26	32
340615	138	3PH	6	4N.HARD138 -4CLOVERPORT138 Line	26	32
340615	138	3PH	6	4N.HARD138 -4HARDINSBURG138 Line	26	32
340615	138	3PH	6	5N.HARD161-4N.HARD138 XFMR		
324231	138	3PH	6	*4CLOVERPORT138 -10CANTAP138 Line	26	32
324231	138	3PH	6	*4CLOVERPORT138 -4GR RVR STL138 Line	26	32
324231	138	3PH	6	*4CLOVERPORT138 -4HARDINSBURG138 Line	26	32
324231	138	3PH	6	*4CLOVERPORT138 -4N.HARD138 Line	26	32
324231	138	3PH	6	*4CLOVERPORT138-GI-2019-003 138 Line	26	32

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name	Reclosing Time (Cycles)	Final Clearing Time (Cycles)
999133	138	3PH	6	GI-2019-029P 138-4HARDINSBURG138 Line	26	32
999133	138	3PH	6	GI-2019-029P 138-4CENT HARDIN138 Line	26	32
324260	138	3PH	6	4HARDINSBURG138-GI-2019-029P 138 Line	26	32
342568	138	3PH	6	4CENT HARDIN138-GI-2019-029P 138 Line	26	32
253623	138	3PH	6	4CLOVERPORT138 -10CANTAP138 Line	26	32
324260	138	3PH	6	4HARDINSBURG138-GI2019-004L 138 Line	26	32
911001	138	3PH	6	GI2019-004L-4HARDINSBURG138 Line	26	32
340616	138	3PH	6	5N.HARD161-4N.HARD138 XFMR		
340616	161	3PH	6	5N.HARD161-5MEADE 161.00 Line	26	32
340616	161	3PH	6	5N.HARD161-5MATANZAS-5PARADISE FP via BRTAP 161.00 Line	26	32
340616	161	3PH	6	5N.HARD161-J753 SUB161.00 Line	26	32

*Reclosing not evaluated because it is currently disabled

Table 5-4
GI-2019-029 Category P2.1 Disturbances

Fault Type	Initial Clearing Time (Cycles)	Fault Name	Event
None	6	GI-2019-029P 138-4HARDINSBURG138 Line	P2.1
None	6	GI-2019-029P 138-4CENT HARDIN138 Line	P2.1
None	6	4CENT HARDIN-BLACKBRANCH138 Line	P2.1

Table 5-5
GI-2019-029 Category P2 Disturbances

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name
324231	138	SLG	6	016_Cloverport_138kV
324231	138	SLG	6	019_Cloverport-138kV-3850
324231	138	SLG	6	020_Cloverport-138kV-3851
324231	138	SLG	6	021_Cloverport-138kV-3852
324231	138	SLG	6	022_Cloverport-138kV-3854
324106	345	SLG	6	037_Hardin-178-718
324261	138	SLG	6	Hardin-178-722
324261	138	SLG	6	Hardin-178-712
324261	138	SLG	6	Hardin-178-702
324261	138	SLG	6	Hardin-178-704
324262	138	SLG	6	Hardin-178-714
324263	138	SLG	6	Hardin-178-724
324262	138	SLG	6	Hardin-178-718
324261	138	SLG	6	Hardin-178-754
324261	138	SLG	6	Hardin-178-744
324261	138	SLG	6	Hardin-178-728
324260	138	SLG	6	Hardinsburg_138
342568	138	SLG	6	4CENT HARDIN_138 804
342568	138	SLG	6	4CENT HARDIN_138 814
342568	138	SLG	6	4CENT HARDIN_138 848
340615	138	SLG	6	N.Hard 138kV_562
340615	138	SLG	6	N.Hard 138kV_552
340616	161	SLG	6	N.Hard 161kV_502-1
340616	161	SLG	6	N.Hard 161kV_502-2

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name
340616	161	SLG	6	N.Hard 161kV_542
340616	161	SLG	6	N.Hard 161kV_512 522
340616	161	SLG	6	N.Hard 161kV_532
999133	138	SLG	6	GI-2019-029P 138-4HARDINSBURG138 Line
999133	138	SLG	6	GI-2019-029P 138-4CENT HARDIN138 Line

Table 5-6
GI-2019-029 Category P3 and P6 Disturbances

Prior Element Outage	Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name	Reclosing Time (Cycles)	Final Clearing Time (Cycles)	Event
4HARDINSBURG138-GI-2019-029P 138 Line	999133	138	GI-2019-029P 138-4CENT HARDIN138 Line	3PH	6	26	32	P6
	342568	138	4CENT HARDIN138-GI-2019-029P 138 Line	3PH	6	26	32	P6
4CENT HARDIN138-GI-2019-029P 138 Line	999133	138	GI-2019-029P 138-4HARDINSBURG138 Line	3PH	6	26	32	P6
	324260	138	4HARDINSBURG138-GI-2019-029P 138 Line	3PH	6	26	32	P6
Brown Unit 3	325957	138	BrownNorth-BrownTap1 138kV line	3PH	6	26	32	P3
	325957	138	BrownNorth-ClaysMill 138kV line	3PH	6	26	32	P3
	325956	138	BrownNorth-Reactor2 138kV line	3PH	6	26	32	P3
	325957	138	4BROWN N 138.00 - 4BROWNCT 138.00 Line	3PH	6	26	32	P3
	325857	138	4BROWN N 138.00 - 4PISGAH 138.00 Line	3PH	6	26	32	P3
	325957	138	4BROWN N 138.00 - 4TYRONE 138.00 Line	3PH	6	26	32	P3
	325956	138	4BROWN N 138.00 - 7BROWN N 345.00 Xfmr	3PH	6	26	32	P3
Mill Creek 4	324108	345	7MILLCRK 345.00 - 7CANERN TAP 345.00 Line	3PH	6	26	32	P3
	324108	345	7MILLCRK 345.00 - 7BLUE LK 345.00 Line	3PH	6	26	32	P3

Prior Element Outage	Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name	Reclosing Time (Cycles)	Final Clearing Time (Cycles)	Event
	324108	345	7MILLCRK 345.00 - 7HARDIN 345.00 Line	3PH	6	26	32	P3
	324108	345	7MILLCRK 345.00 - 7MIDDLTN 345.00 Line	3PH	6	26	32	P3
	324108	345	Mill Creek Unit 3	3PH	6	26	32	P3
	324108	345	Mill Creek - Xfmr 5 345/138/13.8 kV	3PH	6	26	32	P3
GI2019-004	324260	138	4HARDINSBURG138 -4N.HARD138 Line	3PH	6	26	32	P3
	324260	138	4HARDINSBURG138 -4CLOVERPORT138 Line	3PH	6	26	32	P3
	324260	138	4HARDINSBURG138-GI-2019-029P 138 Line	3PH	6	26	32	P3
	324260	138	4HARDINSBURG138-GI2019-004L 138 Line	3PH	6	26	32	P3
GI2019003	990003	138	GI2019003POI-4CLOVERPORT138 Line	3PH	6	26	32	P3
	990003	138	GI2019003POI-4TIP TOP138 Line	3PH	6	26	32	P3
J753	340616	161	5N.HARD161-4N.HARD138 XFMR	3PH	6	26	32	P3
	340616	161	5N.HARD161-5MEADE 161.00 Line	3PH	6	26	32	P3
	340616	161	5N.HARD161-5MATANZAS-5PARADISE FP via BRTAP 161.00 Line	3PH	6	26	32	P3
	340616	161	5N.HARD161-J753 SUB161.00 Line	3PH	6	26	32	P3

Table 5-7
GI-2019-029 Category P4 Disturbances

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name
324231	138	SLG	60	016_Cloverport_138kV
324231	138	SLG	60	019_Cloverport-138kV-3850
324231	138	SLG	60	020_Cloverport-138kV-3851
324231	138	SLG	60	021_Cloverport-138kV-3852
324231	138	SLG	60	022_Cloverport-138kV-3854
324106	345	SLG	60	037_Hardin-178-718
324261	138	SLG	60	Hardin-178-722

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name
324261	138	SLG	60	Hardin-178-712
324261	138	SLG	60	Hardin-178-702
324261	138	SLG	60	Hardin-178-704
324262	138	SLG	60	Hardin-178-714
324263	138	SLG	60	Hardin-178-724
324262	138	SLG	60	Hardin-178-718
324261	138	SLG	60	Hardin-178-754
324261	138	SLG	60	Hardin-178-744
324261	138	SLG	60	Hardin-178-728
324260	138	SLG	60	Hardinsburg_138
342568	138	SLG	60	4CENT HARDIN_138 804
342568	138	SLG	60	4CENT HARDIN_138 814
342568	138	SLG	60	4CENT HARDIN_138 848
340615	138	SLG	60	N.Hard 138kV_562
340615	138	SLG	60	N.Hard 138kV_552
340616	161	SLG	60	N.Hard 161kV_502-1
340616	161	SLG	60	N.Hard 161kV_502-2
340616	161	SLG	60	N.Hard 161kV_542
340616	161	SLG	60	N.Hard 161kV_512 522
340616	161	SLG	60	N.Hard 161kV_532
999133	138	SLG	60	GI-2019-029P 138-4HARDINSBURG138 Line
999133	138	SLG	60	GI-2019-029P 138-4CENT HARDIN138 Line

Table 5-7B
GI-2019-029 Category P4 Disturbances Ran by Idev

Simulation
01 Cloverport to Hardinsburg_LE fault failure at CP.idv
02 Hardinsburg to Cloverport_LE fault failure at HB_island.idv
03 Cloverport to New Hardinsburg_LE fault failure at CP.idv
04 New Hardinsburg to Cloverport_LE fault failure at NHB island.idv
04-HardinCO-BrownN#914-60cyc.idv
05_CentralHardin-POI_BF_Central-Hardin.idv
05-HardinCO-Daviess#934-60cyc.idv
06_Hardinsburg-POI_BF_Hardinsburg.idv
06-HardinCO-MC#954-60cyc.idv
07-HardinCO-BrownN#904-60cyc.idv
08-HardinCO-Daviess#924-60cyc.idv
08-SLG fault-HardinCo138-Rogersville138kV-BF-Rogersville138kV.idv
09-HardinCO-MC#944-60cyc.idv
09-SLG fault-HardinCo138-Central Hardin138kV-BF-Central Hardin138kV.idv
10-HardinCO345-138#944-60cyc.idv
10-SLG fault-HardinCo138-Etown138kV-BF-Etown138kV.idv
11-HardinCO-345-138#924-60cyc.idv
11-SLG fault-HardinCo138-Etown138kV-BF-HardinCo#702.idv
12-HardinCO345-138#904-60cyc.idv
12-SLG fault-HardinCo138-Etown138kV-BF-HardinCo#704.idv
13-HardinCO345-138#908-60cyc.idv
13-SLG fault-HardinCo138-CentralHardin138kV-BF-HardinCo#712.idv
14-SLG fault-HardinCo138-CentralHardin138kV-BF-HardinCo#711.idv
15-SLG fault-HardinCo138-Rogersville138kV-BF-HardinCo#722.idv
16-SLG fault-HardinCo138-Rogersville138kV-BF-HardinCo#754.idv
17-SLG fault-HardinCo138-69kV#1-BF-HardinCo#722.idv
18-SLG fault-HardinCo138-69kV#1-BF-HardinCo#724.idv

Simulation
19-SLG fault-HardinCo138-69kV#2-BF-HardinCo#712.idv
20-SLG fault-HardinCo138-69kV#2-BF-HardinCo#711.idv
21-SLG fault-HardinCo345-138xfmr#1-BF-HardinCo#718.idv
22-SLG fault-HardinCo345-138xfmr#2-BF-HardinCo#702.idv
23-SLG fault-HardinCo345-138xfmr#2-BF-HardinCo#728.idv

Table 5-8
GI-2019-029 Category P4.5 Disturbances

Faulted Bus	kV	Fault Type	Initial Clearing Time (Cycles)	Fault Name
324231	138	SLG	60	016__Cloverport_138kV
324260	138	SLG	60	HARDINSBURG_138kV
340615	138	SLG	60	4N.HARD_138 kV

Table 5-9
GI-2019-029 Category P5 Disturbances

Simulation	Fault Name
06_Hardinsburg-POI_BF_Hardinsburg.idv	265 ___Hardinsburg-184-724
02 Hardinsburg to Cloverport_LE fault failure at HB_island.idv	266 ___Hardinsburg-184-704
03 Cloverport to New Hardinsburg_LE fault failure at CP.idv	139 ___Cloverport-CP-3850
01 Cloverport to Hardinsburg_LE fault failure at CP.idv	143 ___Cloverport-CP-3854
05_CentralHardin-POI_BF_Central-Hardin.idv	4CENT HARDIN_138 804
04 New Hardinsburg to Cloverport_LE fault failure at NHB island.idv	N.Hard 138kV_552
07 POI to Hardinsburg fault failure at POI.idv	GI2019029P_138

Hardin County P5 disturbances were not included in this study as there is existing redundancy.

Table 5-10
GI-2019-029 Category P7 Disturbances

Faulted Bus	kV	Initial Clearing Time (Cycles)	Fault Name	Reclosing Time (Cycles)	Final Clearing Time (Cycles)
324231	138	6	Tip Top-Cloverport 138 kv_ Mill Creek-Hardin County 345 kv 2	26	32
324106	345	6	Tip Top-Cloverport 138 kv_ Mill Creek-Hardin County 345 kv 2	26	32
324261	138	6	Central Hardin-Hardin County 138 kv_ Mill Creek-Hardin County 345 kv 2	26	32
324106	345	6	Central Hardin-Hardin County 138 kv_ Mill Creek-Hardin County 345 kv 3	26	32
342568	138	6	Central Hardin-Hardin County 138 kv_ Mill Creek-Hardin County 345 kv 1	26	32
324106	345	6	Central Hardin-GI-2019-029P 138 kv_ Mill Creek-Hardin County 345 kv 3	26	32
342568	138	6	Central Hardin-GI-2019-029P 138 kv_ Mill Creek-Hardin County 345 kv 1	26	32
999133	138	6	Central Hardin-GI-2019-029P 138 kv_ Mill Creek-Hardin County 345 kv 2	26	32

5.4 Powerflow Solution Method

Models were solved with automatic control of Load Tap Changers (LTCs), area interchange, phase shifters and switched shunts enabled.

5.5 Monitored Elements

The transient stability performance of the transmission system was monitored at some key generating facilities in the LG&E and KU control area and neighboring control areas which are in the vicinity of the subject request.

5.6 Performance Criteria

Disturbances were evaluated as per criteria given in the LG&E and KU Transmission Planning Guidelines.

5.7 Relay Settings

5.7.1 Customer Relay Settings

In initially testing the P1 disturbances it was found that with the addition of the GI-2019-029 generation and its provided protection settings, the GI-2019-029 solar generation would trip due to the provided voltage settings for the disturbance shown in Table 5-11. Only a few select disturbances near the POI were tested for this initial analysis.

Table 5-11
Disturbances with GI-2019-029 Tripping in Initial Results due to Voltage settings

Models	3Phase P1 Disturbances with a fault near the GI-2019-029 POI on the following lines
2021 Summer Generation Maximization	GI-2019-029P138-4CENTHARDIN138
2024 Light Load Model	GI-2019-029P138-4CENTHARDIN138
2029 Summer Peak Model	GI-2019-029P138-4CENTHARDIN138

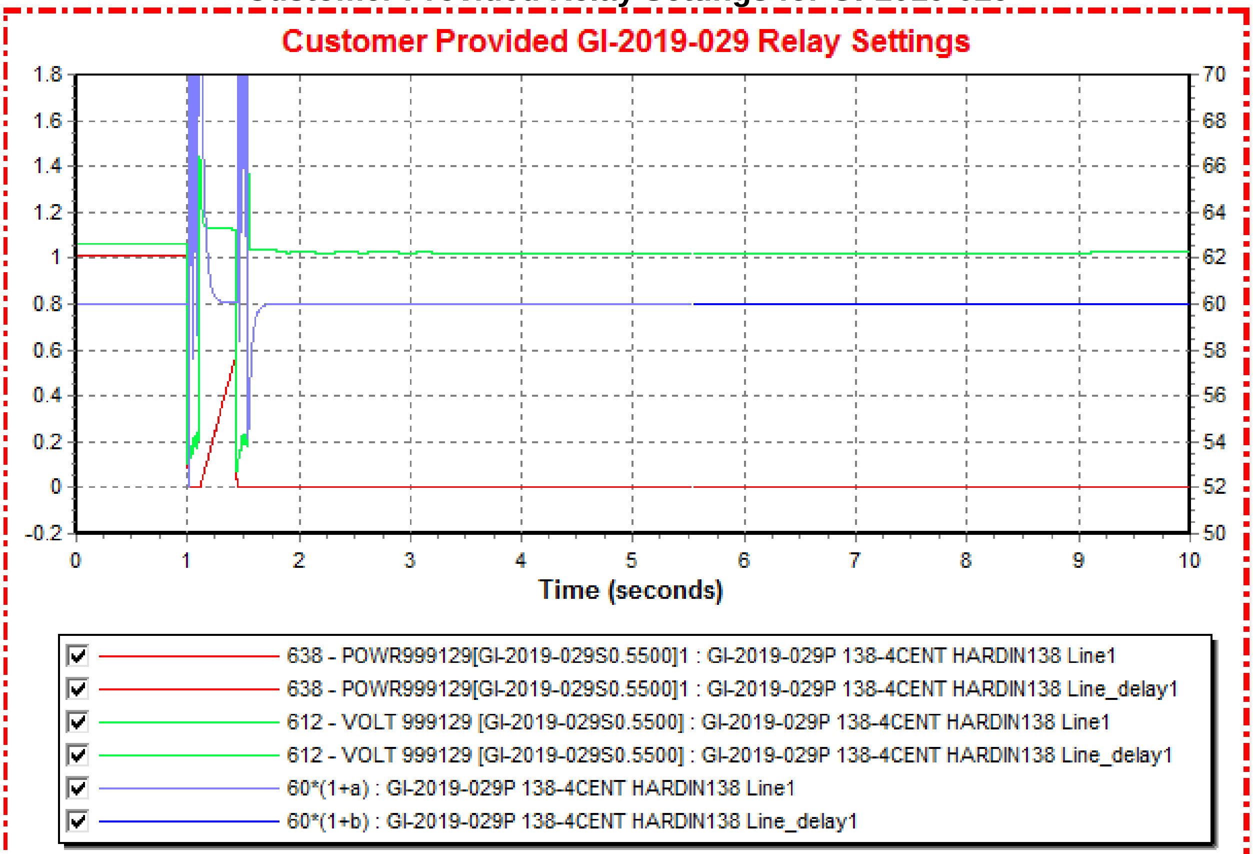
Table 5-12 shows the GI-2019-029 customer indicated relay setting. The particular setting which initiated the generation trip is shown in red font in Table 5-12.

Table 5-12
Customer Provided Relay Pickup time for GI-2019-029 Relay Settings

Relay Identifier Number	Protection module	Upper Bandwidth	Low Bandwidth	Customer Provided Relay pick up Time	Breaker Delay Time
99913301	VTGDCAT	1.2000	-1.0000	0.01000	0

Figure 5-1 shows 2029S results for the GI-2019-029P138-4CENTHARDIN138 disturbance illustrating that the GI-2019-029 generation trips with the settings shown in Table 5-13.

Figure 5-1
2029S Model
Customer Provided Relay Settings for GI-2019-029



5.7.2 Modified Relay Settings

Further review revealed that the GI-2019-029 generation would remain on-line if a modification to the relay settings was made. The ITO studied the following potential relay setting change:

- Modify the relay pickup time for one of the GI-2019-029 generator relays increasing from 0.01 to 0.011 pu as shown in Table 5-13.

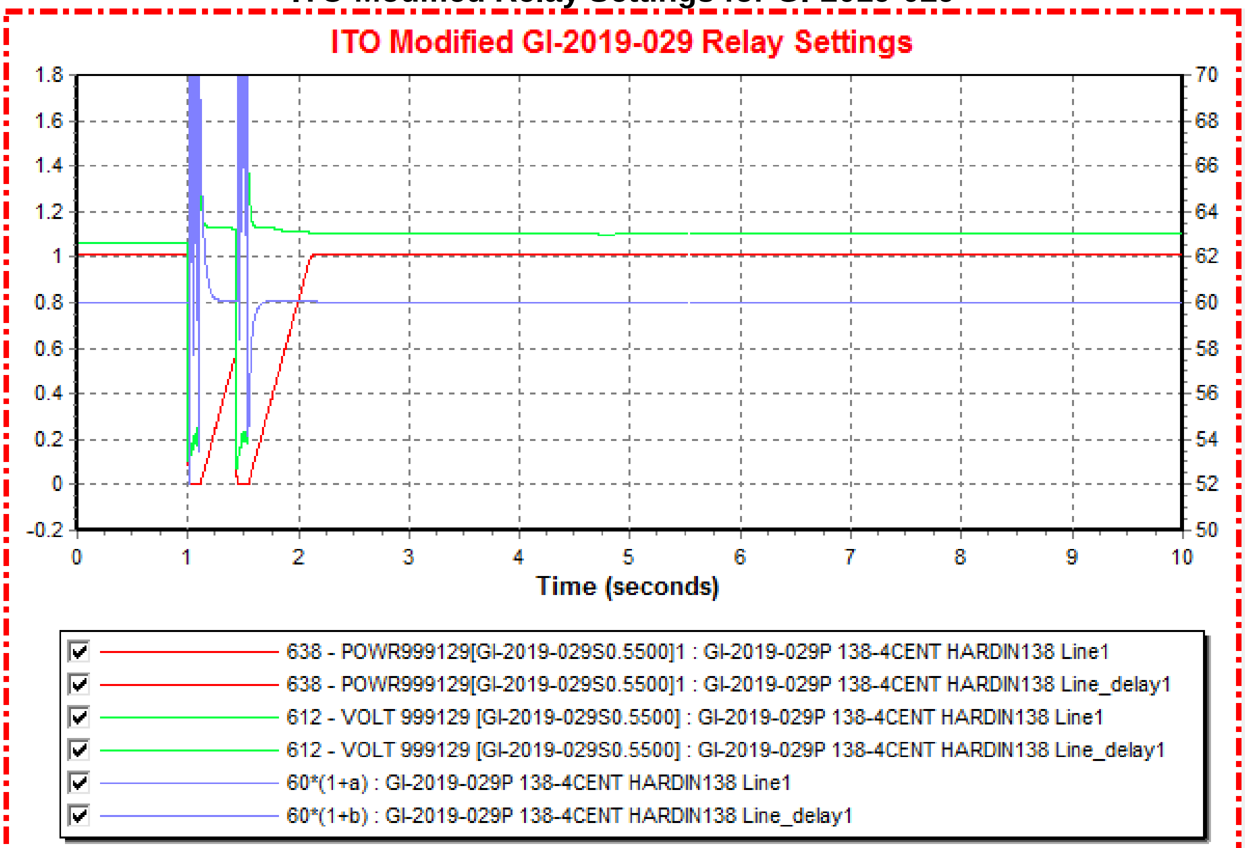
Table 5-13
Modified Relay Upper Bandwidth for GI-2019-029 Relay Setting

Relay Identifier Number	Protection module	Upper Bandwidth	Low Bandwidth	ITO Suggested Relay pick up Time	Breaker Delay Time
99913301	VTGDCAT	1.2000	-1.0000	0.01100	0

Figure 5-2 shows the 2029S results for the GI-2019-029P138-4CENTHARDIN138 disturbance illustrating that the GI-2019-029 generation does not trip when the relay settings are modified as shown in Table 5-13.

Figure 5-2

2029S Model
ITO Modified Relay Settings for GI-2019-029



5.8 Detailed Results

The study was performed assuming the relay settings shown in Table 5-13. All study results are contingent on this assumption.

5.8.1 Solar Bus Angle Drift Issues

A simulation with no fault applied showed a slight drift in the bus angles for some solar generation buses in PSSE 33.12.1. This issue was found prior to adding the GI-2019-029 generation to the models and remained after the addition of the GI-2019-029 generation. As discussed with LG&E and KU and explained in Section 5.7.1 of the GI-2019-003 SIS Report, solar bus angle drift is considered to be a non-issue.

5.8.2 Impedance swing

To address Sections 4.1.2 and 4.3.1.3 of the TPL-001-4 standard, stability analysis was performed to assess tripping due to transient swings. The goal of the apparent impedance swing test is to determine if there are any breaker mis-operations as a result of an apparent impedance swing during the stability simulation. The breakers need to be able to clear the fault during normal or delayed clearing events. However, non-faulted facilities need to remain in service. Distance relays, which are designed to determine if a fault is on the system, could mis-operate due to an apparent impedance swing resulting in tripping of facilities that are not needed in order to clear the fault.

5.8.2.1 Distance Relay Setup

The PSSE distance relay model DISTR1 was used. Each BES transmission line in LKE's control area was assumed to be equipped with 2 DISTR1 relays, one at each end, and the setting for these relays were assumed to be as provided in Table 5-14.

Table 5-14: Assumed Distance Relay Input Values

Value	Description
2	Zone 1 pick-up time (cycles)
90%	Zone 1 reach (diameter or reactance) (pu)
75	Zone 1 centerline angle (degrees)
50%	Zone 1 center distance
22	Zone 2 pick-up time (cycles)
120%	Zone 2 reach (diameter or reactance) (pu)
75	Zone 2 centerline angle (degrees)
60%	Zone 2 center distance
4	Self-trip breaker time (cycles)

The GI-2019-029 results did not include extra tripping due to impedance swings.

5.9 Conclusion

The ITO studied the P1 - P7 category disturbances as mentioned in Section 5.3. With the ITO suggested modifications to the GI-2019-029 generation relay settings, all tested disturbances passed the stability criterion. Plots of all simulation results are available upon request.

These study results rely on the following:

- Modifications to relay settings for the GI-2019-029 generation as provided in Table 5-13. The customer must work with the TO and ITO during the Facilities Study (FS) to determine mutually agreeable relay settings. The voltage relay setting modifications must be verified with the manufacture by the customer for any technical limitation or generator protection issues. If the Table 5-13 modified settings cannot be used, additional study maybe required.
- For a simulation with no fault, slight drift in bus angles for some solar generation buses in PSSE 33.12.1 were ignored as discussed in Section 5.8.1.

In the process of performing the GI-2019-029 Stability Analysis, the ITO found two P4/P5 disturbances that resulted in islanding, 02 Hardinsburg to Cloverport_LE fault failure at HB and 04 New Hardinsburg to Cloverport_LE fault failure at NHB. LG&E/KU has indicated that it plans to install Undervoltage and Underfrequency protection at the new interconnection's terminal as anti-islanding protection, and the protection should function under the fault scenarios listed. However, detailed clearing times are not available since specific settings for this protection have not been developed and will require coordination with the generator owner. Absent detailed fault clearing times, the ITO ran the faults assuming the islands will disconnect within 1 second of being formed. No criteria violations were identified under this assumption. Prior to the in-service date, the generator owner is required to coordinate with LG&E/KU to ensure the proper protection settings are in place to prevent the potential islanding events.

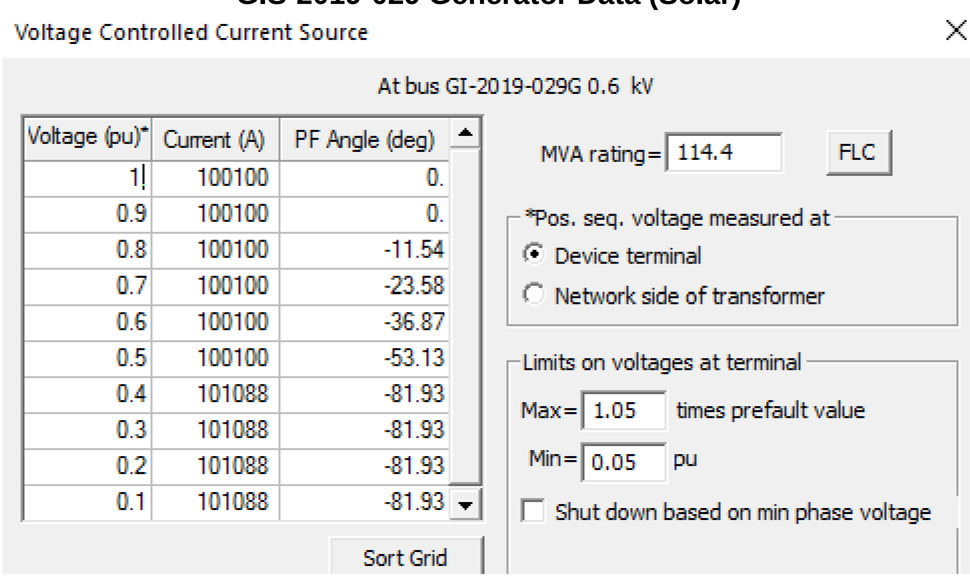
6. Short Circuit Analysis

A short circuit analysis was performed using ASPEN by simulating three-phase faults and single line-to-ground faults for buses within a five-bus radius of the POI to determine the breaker duty in both the pre and post LGE-GIS-2019-029 models. The breaker duty for these simulations was compared to the rated breaker interrupting capability to determine whether or not the circuit breakers may be overstressed. A breaker is considered a Significantly Affected Facility (SAF) if the breaker duty at that breaker is equal to or greater than the rated breaker interrupting capability, and the impact of the new generation is greater than or equal to 5% of the rated breaker interrupting capability. The short circuit models emulated the steady-state modeling as closely as practical and appropriate. The analysis results are summarized in Table 6-2.

6.1 Model Development

The starting model for the GI-2019-029 Short Circuit Analysis was a model provided by LG&E and KU in conjunction with LG&E and KU's 2020 TEP. The TEP_2026_2020-03-18. OLR model was modified by adding the Table 3-10 prior queued requests to form the Pre GIS-2019-029 model. The Pre GIS-2019-029 model was modified by adding the GIS-2019-029 generation at the POI and the mitigation identified in the steady state analysis to form the Post GIS-2019-029 model. The solar inverter was modeled as a voltage controlled current source in Aspen as shown in Table 6-1.

Table 6-1
GIS-2019-029 Generator Data (Solar)


Voltage Controlled Current Source

At bus GI-2019-029G 0.6 kV

Voltage (pu)*	Current (A)	PF Angle (deg)
1	100100	0.
0.9	100100	0.
0.8	100100	-11.54
0.7	100100	-23.58
0.6	100100	-36.87
0.5	100100	-53.13
0.4	101088	-81.93
0.3	101088	-81.93
0.2	101088	-81.93
0.1	101088	-81.93

Sort Grid

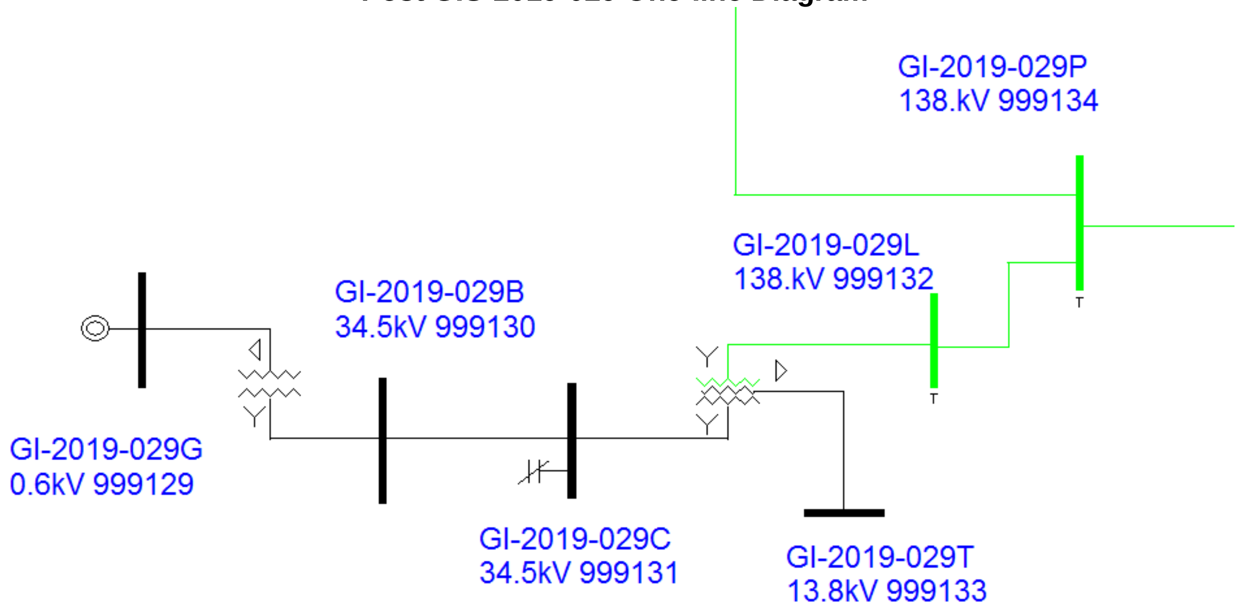
MVA rating= 114.4 FLC

*Pos. seq. voltage measured at
Device terminal
Network side of transformer

Limits on voltages at terminal
Max= 1.05 times prefault value
Min= 0.05 pu
Shut down based on min phase voltage

Figures 6-1 illustrates the connection of the GIS-2019-029 request in the Post GIS-2019-029 short circuit model.

Figure 6-1
Post GIS-2019-029 One-line Diagram



6.2 Short Circuit Calculations

Short circuit calculations were performed to determine the impact of the proposed project on the breaker duties at nearby substations (within 5 buses). Single-phase and 3-phase symmetrical breaker duty levels were calculated at local area buses, both with and without the proposed project.

No breakers were found to be overstressed in the Post GIS-2019-029 short circuit analysis.

For informational purposes only, Table 6-2 list breakers near the POI and shows the % impacts of the GI-2019-029 generation addition on their breaker duties. The impact of the GI-2019-029 generation is given in the “Impact of Request as a % of Breaker Capability” column. The maximum breaker duty for all faults tested is given for each breaker in both Amperes and as a percentage of the applicable breaker interrupting capability rating.

Table 6-2
Pre and Post GIS-2019-029 Breaker Duty for Substations near POI

BKR_ID	Bus	BKR Capacity	Pre		Post		Impact as a % of Breaker Duty
			Duty Ampere	% Duty	Duty Ampere	% Duty	
178-712	"HARDN CO 138.kV"	40000	23321	58.3	23489	58.7	0.4%
178-714	"HARDN CO 138.kV"	40000	23321	58.3	23489	58.7	0.4%
178-724	"HARDN CO 138.kV"	40000	23296	58.2	23462	58.7	0.4%
178-722	"HARDN CO 138.kV"	40000	23960	59.9	24101	60.3	0.4%
178-754	"HARDN CO 138.kV"	40000	23960	59.9	24101	60.3	0.4%
178-702	"HARDN CO 138.kV"	40000	23242	58.1	23379	58.4	0.3%
178-704	"HARDN CO 138.kV"	63000	23242	36.9	23379	37.1	0.2%
178-728	"HARDN CO 138.kV"	63000	19151	30.4	19267	30.6	0.2%
178-718	"HARDN CO 138.kV"	63000	18859	29.9	18968	30.1	0.2%
178-618	"HARDN CO 69.kV"	40000	25024	62.6	25090	62.7	0.2%
178-624	"HARDN CO 69.kV"	34756	30831	88.7	30888	88.9	0.2%
178-604	"HARDN CO 69.kV"	34756	29984	86.3	30038	86.4	0.2%
178-602	"HARDN CO 69.kV"	40000	23308	58.3	23370	58.4	0.2%
178-634	"HARDN CO 69.kV"	40000	29523	73.8	29577	73.9	0.1%
178-614	"HARDN CO 69.kV"	40000	29520	73.8	29572	73.9	0.1%
034-644	"ETOWN 69.kV"	34756	28519	82.1	28556	82.2	0.1%
034-654	"ETOWN 69.kV"	34756	27642	79.5	27677	79.6	0.1%
034-624	"ETOWN 69.kV"	40000	28065	70.2	28102	70.3	0.1%
034-634	"ETOWN 69.kV"	40000	28519	71.3	28556	71.4	0.1%
034-602	"ETOWN 69.kV"	40000	28518	71.3	28556	71.4	0.1%
034-614	"ETOWN 69.kV"	40000	27646	69.1	27684	69.2	0.1%
178-608	"HARDN CO 69.kV"	40000	25108	62.8	25143	62.9	0.1%
034-674	"ETOWN 69.kV"	40000	26753	66.9	26787	67	0.1%
034-604	"ETOWN 69.kV"	40000	26175	65.4	26195	65.5	0.0%
184-704	"HARDINSB 138.kV"	19484	12063	61.9	12068	61.9	0.0%
184-724	"HARDINSB 138.kV"	40000	11246	28.1	11246	28.1	0.0%
184-714	"HARDINSB 138.kV"	19484	8962	46	8961	46	0.0%
178-744	"HARDN CO 138.kV"	40000	22850	57.1	22843	57.1	0.0%
034-608	"ETOWN 69.kV"	40000	23286	58.2	23257	58.1	-0.1%
455-708	"BLACKBRNCH 138.kV"	63000	15667	24.9	15600	24.8	-0.1%

As shown in Table 6-2, the breaker duties seen by all breakers listed are less than their rated interrupting capabilities in both the pre and post analyses. Thus, there are no short circuit constraints to granting the GI-2019-029 GI request.

6.3 Conclusion

There are no short circuit constraints to granting the GI-2019-029 GI request.

7. Stiffness Verification due to Inverter Based Resource Interconnection:

The stiffness of the grid decreases with the higher penetration of Inverter Based Resources (IBRs) or with larger electrical distance to the synchronous generation. Short circuit ratio (SCR) is used as a traditional metric to determine the relative strength of a power system. It is the ratio between short circuit apparent power (SCMVA) from a three line to ground fault at a given location in the power system to the rating of the IBR connected to that location. It is defined as

$SCR = S_{SCMVA\_POI} / P_{RMW\_VER}$

Where S_{SCMVA_POI} is the short circuit MVA level at the POI without the new IBR interconnection, and PRMW_VER is the nominal power rating of the IBR being connected at the POI. As per LG&E and KU's GI Study Criteria the SCR metric is appropriate for a single IBR operating in the portion of the grid without other IBRs or power electronic-based equipment electrically close to the POI.

LG&E/KU adopts NERC's recommendation to apply a Weighted SCR (WSCR) method for high IBR penetration, which considers the interaction and oscillation between IBRs where the POIs are electrically close to each other. The WSCR is defined as

$WSCR = (\Sigma S_{SCMVAi} * P_{RMW}) / (\Sigma P_{RMWi})^2$

As per LG&E and KU's GI Study Criteria the WSCR MVA would be calculated where appropriate and if the SCR or WSCR, whichever applies, is less than 2.0, mitigations are required.

GI-2019-029 Stiffness Verification Procedure:

- The GI-2019-029 Generations were taken offline in the Aspen model
- A 3 Phase fault was applied at the GI-2019-029 POI bus in Aspen and the short circuit MVA level at the GI-2019-029 POI bus was calculated.
- The Short circuit MVA at the GI-2019-029 POI bus was determined to be 2778.8 MVA
- The GI-2019-029 inverter rating in MW connected is 100 MW.

Using the $SCR = S_{SCMVA\_POI} / P_{RMW\_VER}$ = (2778.8 MVA) / (100 MW) = 27.8

7.1 Conclusion

Since the GI-2019-029 SCR is 27.8, which exceeds the requirement of 2.0, there are no Grid Stiffness constraints to granting the GI-2019-029 GI request.

8. Conceptual Cost Estimate

This report does not consider any issues related to the proposed routing of the generator lead-line to connect to the Transmission Owners Transmission System. If it is later determined that there are line clearance issues related to the generator's proposed lead-line, the customer must provide an alternate route that avoids such issues. In the event an alternate route is not available, the Transmission Owner may need to modify its transmission facilities to maintain adequate clearances. The Customer will be responsible for the costs and any schedule delay as a result.

There were no LG&E and KU constraints identified in the stability or short circuit analyses. However there were LG&E and KU constraints identified in the steady state analysis. Thus, LG&E and KU has provided a non-binding good faith cost estimate to mitigate the LG&E and KU constraints. Also a non-binding good faith cost estimate is provided for interconnection facilities of request LGE-GIS-2019-029. The same interconnection facilities were identified for both NRIS and ERIS. The NRIS mitigation facilities differed slightly from the ERIS mitigation facilities. These are only conceptual cost estimates for planning purposes. These costs were compiled by LG&E and KU and will be further developed and refined in the Facility Study.

8.1 Methodology

The cost estimates are allocated based on the "*Allocation of Costs for Generator Interconnections"* dated 01/01/2018 posted on OASIS.

8.2 Generator Owner Facilities

The generator owner is responsible for the installation and costs for the generator, step up transformer and customer protective devices up to the Transmission Owner (TO) metering equipment. The customer is responsible for determining the generator owner costs for the facilities owned and operated by the customer.

8.3 Total Conceptual Cost Estimate:

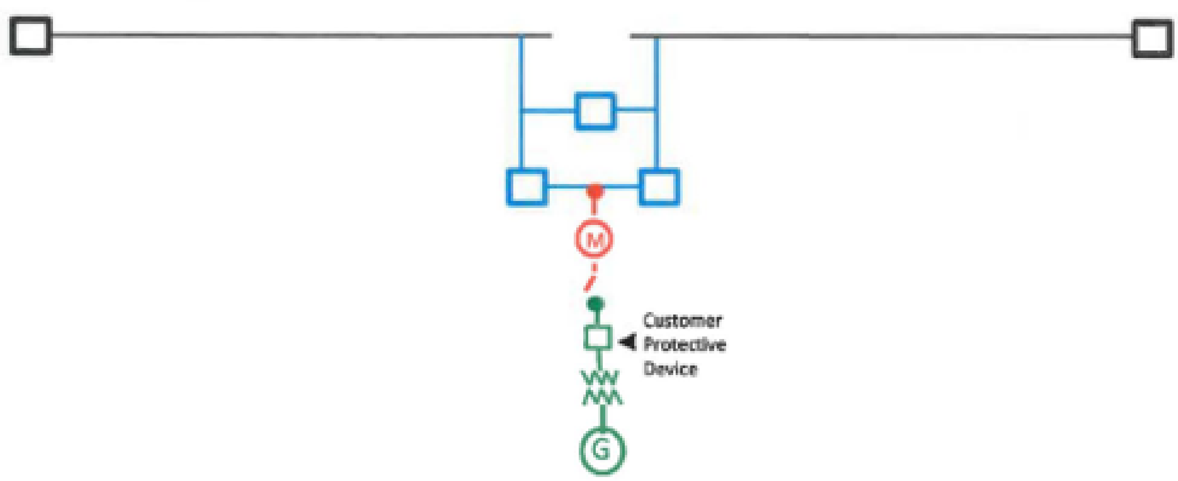
Total Conceptual Cost Estimate	
Service Type	**Estimated Cost**
NRIS	$16,015,077
ERIS	$12,681,186

The costs and facilities identified are as follows.

Unless the customer chooses a more reliable interconnection, the minimum generator interconnection facilities are shown in Figure 8-1.

Figure 8-1: Minimum Generator Interconnection Facilities

New Ring Bus Configuration



Legend:

Black = Existing Transmission Facilities
Blue = New Network Facilities
Red = Transmission Interconnection Facilities
M = Interconnection Metering and Associated Equipment
Green = Generation Facilities
● = Point of Interconnection
● = Point of Change of Ownership

8.3.1 Transmission Interconnection Facilities: (Total Estimated Cost $1,767,230)

The customer is responsible for transmission interconnection facilities between the generator owner facilities and the point of interconnection. The LG&E and KU non-binding planning level cost estimate for transmission interconnection facilities is shown in Table 8-1 and includes the following:

- One (1) 138kV Motor-Operated Disconnect Switch
- Three (3) 138kV Surge Arresters
- Three (3) 138kV Metering CCVTs
- Three (3) 138kV Metering CTs
- Two (2) 138kV SSVTs (Split Cost between Network and Transmission Interconnect as described above)
- One (1) Steel A-Frame structure
- Six (6) 1-Phase CCVT/ Metering CT Supports
- Two (2) SSVT Supports (Split Cost)
- One (1) slab foundation for new control enclosure and associated entrance mats (Split Cost)
- One (1) New Control House Space Allocation (split cost) consisting of below relay panels:
    - (1) line protection panel for GI Interconnect
    - (1) metering panel for GI
    - (1) RTU panel
    - AC/DC systems (Split Cost)

Table 8-1
Transmission Interconnection Facility Cost Estimate

Description	TIF Subs Cost
Company Labor	$207,681
Contract Labor	$716,387
Materials	$682,505
Contingency	$160,657
Total	$1,767,230

8.3.2 Network Facilities:

Network Facilities Cost Estimate	
Service Type	**Estimated Cost**
NRIS	$14,247,847
ERIS	$10,913,956

8.3.2.1 Network Interconnection Facilities: (Total Estimated Cost $6,609,772)

- The new network interconnection facility will be a three (3) breaker ring bus arrangement with three (3) 138kV lines (Hardinsburg, Central Hardin, & GI Interconnect) and the following equipment:
- Three (3) 138kV Circuit Breakers
- Six (6) 138kV Manually Operated Disconnect Switches
- Six (6) 138kV Surge Arresters
- Six (6) 138kV CCVTs
- Two (2) 138kV SSVTs (Split Cost between Network and Transmission Interconnect as described above)
- Two (2) Steel A-Frame structures
- Two (2) 3-Phase Low Bus Supports
- Fifteen (15) 1-Phase Low Bus Supports
- Four (4) 1-Phase High Bus Supports
- Two (2) Low Disconnect Switch Support Stands
- Four (4) High Disconnect Switch Support Stands
- Six (6) 1-Phase CCVT Supports
- Two (2) SSVT Supports (Split Cost)
- One (1) slab foundation for new control enclosure and associated entrance mats (Split Cost)
- One (1) Lightning Mast
- One (1) Small (14' x 42') control house (split cost) consisting of the following:
  - (2) line protection panels for Hardinsburg & Central Hardin (EKPC)
  - (2) Digital communications paths, (1) associated with the Hardinsburg line and (1) associated with the Central Hardin (EKPC) line
  - (1) RTU panel
  - (1) DFR panel

  - AC/DC systems (Split Cost)
- One (1) new Line relay panel at Hardinsburg
- Two (2) 138kV three (3) pole, caisson supported, steel deadened structures and foundations
- Hardware and Conductor for taps from existing 138kV line to the station structure
- Two (2) OPGW splice boxes
- Di-electric Fiber Cable (24-SM) for End Section
- Fiber Termination Panel
- AFL Fiber Splice Enclosure, Trays & Bushings
- Slack Drum
- ICON Multiplexer e/w required access modules
- 48VDC Power Plant
- 125/48 VDC-DC Converter (1:4 system)
- 90H" x 19W" Hybrid Relay Rack

Table 8-2
Network Interconnection Facility Cost Estimate

Description	Cost
Company Labor	$688,415
Contract Labor	$2,543,781
Contracted Materials	$2,776,688
Contingency	$600,888
Total	$6,609,772

LG&E and KU has indicated that the interconnection facilities can be completed within 24 months after the GIA is signed.

8.3.2.2 Network Upgrade Facilities

Network Upgrade Facilities Cost Estimate	
Service Type	**Estimated Cost**
NRIS	$7,638,075
ERIS	$4,304,184

LG&E and KU potential network thermal constraints were identified in the NRIS and ERIS steady state analysis as shown in Table 4-1 and Table 4-5, respectively. The network upgrade facilities alleviate the Table 4-1 and Table 4-3 constraints for NRIS and ERIS as detailed in LG&E/KU's

non-binding planning level cost estimate for network upgrade facilities as shown in Tables 8-3 and 8-4.

Table 8-3
LG&E and KU Network Upgrade Facilities Cost and Need Date

Overloaded Facility	Mitigation Description	Cost		Date	
		NRIS	ERIS	NRIS	ERIS
Elizabethtown to Kargle 69 kV line	Replace all 69 kV terminal equipment rated less than 953 Amps (114 MVA) summer emergency rating associated with the Elizabethtown to Kargle 69 kV line.	$95,413	$95,413	02/01/2024	05/30/2024
Black Branch to Central Hardin 138 kV line	Replace 0.83 miles of 954 MCM 45X7 ACSR in the Black Branch to Central Hardin 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,333,891	**Not Needed**	05/30/2024	**Not Needed**
Black Branch to GI-2019-029 POI 138 kV line	Replace 2.002 miles of line from Black Branch to GI-2019-029 POI 138 kV in the Black Branch to Hardinsburg 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,935,696	$3,935,696	05/30/2024	05/30/2024
Hardinsburg to New Hardinsburg 138 kV line	Replace all 138 kV terminal equipment rated less than 993 Amps (237 MVA) summer emergency rating associated with the Hardinsburg to New Hardinsburg 138 kV line.	$273,075	$273,075	0201/2024	02/01/2024
Total		$7,638,075	$4,304,184		

Table 8-4
LG&E and KU Network Upgrade Facilities Cost Details

Overloaded Facility	Company Labor	Contract Labor	Materials	Contingency	Total
Elizabethtown to Kargle 69 kV line	$30,614	$43,710	$12,415	$8,674	$95,413
Black Branch to Central Hardin 138 kV line	$301,744	$2,025,435	$474,410	$532,302	$3,333,891
Black Branch to GI-2019-029 POI 138 kV line	$326,464	$2,121,306	$859,537	$628,389	$3,935,696
Hardinsburg to New Hardinsburg 138 kV line	$37,105	$143,268	$67,877	$24,825	$273,075
Total	$695,927	$4,333,719	$1,414,239	$1,194,190	$7,638,075

LG&E and KU has indicated that the mitigation facilities can be completed within 36 months after the GIA is signed.

Service could be granted without mitigation if the MW output of the GI-2019-029 generation were reduced. Table 8-5 details the MW limitations required.

Table 8-5
GI-2019-029 MW limit without Mitigation Required

Overloaded Facility	Mitigation Description	Cost	MW Available	
		NRIS	**NRIS**	**ERIS**
Elizabethtown to Kargle 69 kV line	Replace all 69 kV terminal equipment rated less than 953 Amps (114 MVA) summer emergency rating associated with the Elizabethtown to Kargle 69 kV line.	$95,413	67	83
Black Branch to Central Hardin 138 kV line	Replace 0.83 miles of 954 MCM 45X7 ACSR in the Black Branch to Central Hardin 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,333,891	99	100
Black Branch to GI-2019-029 POI 138 kV line	Replace 2.002 miles of line from Black Branch to GI-2019-029 POI 138 kV in the Black Branch to Hardinsburg 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,935,696	57	66
Hardinsburg to New Hardinsburg 138 kV line	Replace all 138 kV terminal equipment rated less than 993 Amps (237 MVA) summer emergency rating associated with the Hardinsburg to New Hardinsburg 138 kV line.	$273,075	28	26
Overall MW Available without Mitigation			28	26

As discussed in Section 4, after completion of the GI-2019-029 analysis but prior to the issuance of this report, the GI-2019-020 and GI-2019-023 customers notified the ITO of withdrawal of the GI-2019-020 and GI-2019-023 requests from the LG&E and KU GI queue. The ITO subsequently performed a sensitivity analysis of the impact of these withdrawals on the GI-2019-029 constraints. The results of that analysis are provided in Section 4. As can be seen from Section 4 Tables 4-3 and 4-7 with withdrawal of the GI-2019-020 and GI-2019-023 requests, the Black Branch to Central Hardin 138 kV line, was not found to overload in the either the NRIS or ERIS analysis but the remaining identified constraints were identified as constraints in both the NRIS and ERIS analyses even with the withdrawal of the GI-2019-020 and GI-2019-023 requests. Based on the sensitivity analysis, which indicated that the Black Branch to Central Hardin 138 kV line upgrade is not required even in NRIS, the network upgrade costs for NRIS would be the same as the ERIS upgrade cost shown in Tables 8-3. Also based on the sensitivity analysis, the MW of Service which could be granted without mitigation if the MW output of the GI-2019-029 generation were reduced was calculated. Table 8-6 details the MW limitations required.

Table 8-6
Limited Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023
GI-2019-029 MW limit without Mitigation Required

Overloaded Facility	Mitigation Description	Cost	MW Available	
		NRIS	NRIS	ERIS
Elizabethtown to Kargle 69 kV line	Replace all 69 kV terminal equipment rated less than 953 Amps (114 MVA) summer emergency rating associated with the Elizabethtown to Kargle 69 kV line.	$95,413	77	89
Black Branch to Central Hardin 138 kV line	Replace 0.83 miles of 954 MCM 45X7 ACSR in the Black Branch to Central Hardin 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,333,891	100	100
Black Branch to GI-2019-029 POI 138 kV line	Replace 2.002 miles of line from Black Branch to GI-2019-029 POI 138 kV in the Black Branch to Hardinsburg 138 kV line with 1272 MCM 45x7 ACSR conductor or better.	$3,935,696	62	70
Hardinsburg to New Hardinsburg 138 kV line	Replace all 138 kV terminal equipment rated less than 993 Amps (237 MVA) summer emergency rating associated with the Hardinsburg to New Hardinsburg 138 kV line.	$273,075	28	26
Overall MW Available without Mitigation			28	26

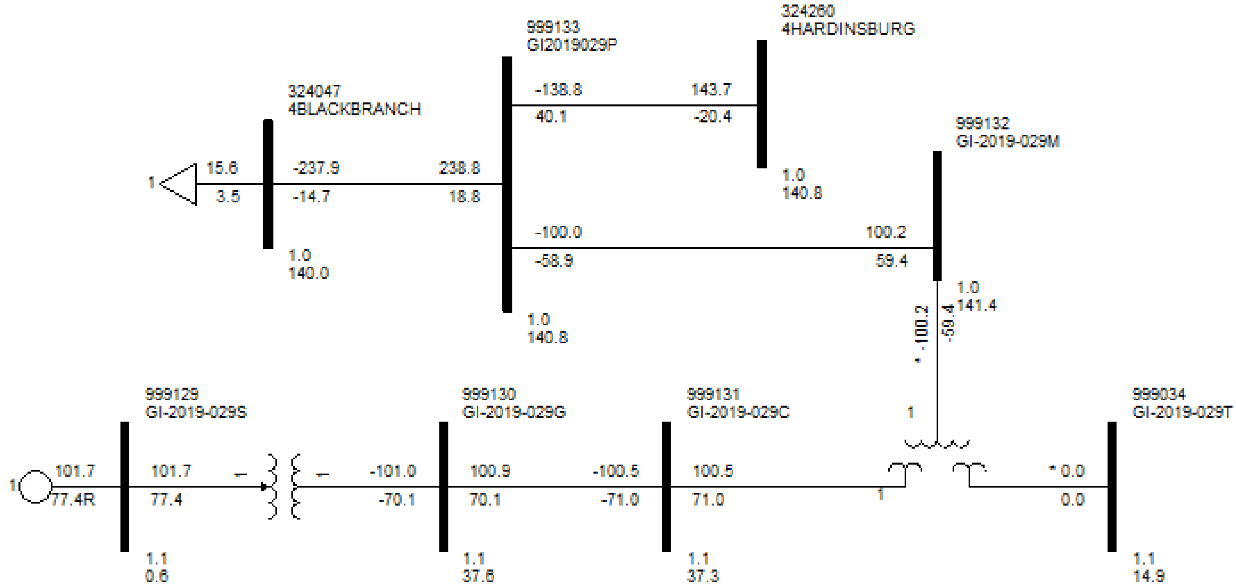
8.3.3 Distribution Facilities: (Total Estimated Cost $0 USD)

No distribution facility upgrades have been identified.

Appendix A: One Line Diagram

One Line Diagram for the proposed GI-2019-029 Solar GI Request

Point of Interconnection



Appendix B: Generation Dispatch Scenarios

It is important to note that the _MERIT_MISO simulations will not result in any generation import from MISO as the MERIT generation is adequate to compensate for the largest generation outage in all study models. As such the _MERIT_MISO simulations fulfill the LG&E and KU Planning Guidelines paragraph:

To maintain the capability to serve LSE load after loss of a LSE's affiliate generator within the LG&E/KU PC area, replacement generation shall be initially selected from available dispatchable LSE affiliate generation resources within the LG&E/KU PC area based on the merit order in the year two summer peak model. Any deficit in replacement generation not covered from affiliate resources within the LG&E/KU PC area shall be replaced with an import from Tennessee Valley Authority (TVA), Midcontinent Independent System Operator (MISO) or PJM unless customer discussions indicate that some of these scenarios are not required

Table B-1
Generation Dispatch Scenarios Studied

Dispatch Code	Description
17-2_MISO	Outage of GI 2017-002, replace with import from MISO (XEL).
17-3_MERIT_MISO	Outage of GI 2017-003, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-1_MERIT_MISO	Outage of GI 2019-001, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-2_MERIT_MISO	Outage of GI 2019-002, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-3_MERIT_MISO	Outage of GI 2019-003, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-4_MERIT_MISO	Outage of GI 2019-004, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-8_MERIT_MISO	Outage of GI 2019-008, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-15_MERIT_MISO	Outage of GI 2019-015, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).

Dispatch Code	Description
19-20_MERIT_MISO	Outage of GI 2019-020, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-23_MERIT_MISO	Outage of GI 2019-023, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
19-25_MERIT_MISO	Outage of GI 2019-025, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
S_CR7_MERIT_MISO	Start up of Cane Run 7, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
S_GH1_MERIT_MISO	Start up of Ghent 1, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
S_GH3_MERIT_MISO	Start up of Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
S_MC4_MERIT_MISO	Start up of Mill Creek 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
BR3_MERIT_MISO	Outage of Brown 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
BR7_MERIT_MISO	Outage of Brown 7, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
CR7_MERIT_MISO	Outage of Cane Run 7, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
GH1_MERIT_MISO	Outage of Ghent 1, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
GH3_MERIT_MISO	Outage of Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
MC4_MERIT_MISO	Outage of Mill Creek 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
PR13_MERIT_MISO	Outage of Paddys Run 13, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
TC2_MERIT_MISO	Outage of Trimble County 2, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
OHF_MERIT_MISO	Outage of Ohio Falls Hydro 1-4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).

Dispatch Code	Description
s_GH1_3_MERIT_MISO_2U	Two unit outage - Start up of Ghent 1 and an outage of Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_GH3_1_MERIT_MISO_2U	Two unit outage - Start up of Ghent 3 and an outage of Ghent 1, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_GH3_4_MERIT_MISO_2U	Two unit outage - Start up of Ghent 3 and an outage of Ghent 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_GH3_BR3_MERIT_MISO_2U	Two unit outage - Start up of Ghent 3 and an outage of Brown 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_MC4_MC3_MERIT_MISO_2U	Two unit outage - Start up of Mill Creek 4 and an outage of Mill Creek 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_MC4_TC2_MERIT_MISO_2U	Two unit outage - Start up of Mill Creek 4 and an outage of Trimble Co 2, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_CR7_PR_MERIT_MISO_2U	Two unit outage - Start up of Cane Run 7 and an outage of Paddys Run 13, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_CR7_MC4_MERIT_MISO_2U	Two unit outage - Start up of Cane Run 7 and an outage of Mill Creek 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_MC4_CR7_MERIT_MISO_2U	Two unit outage - Start up of Mill Creek 4 and an outage of Cane Run 7, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_GH1_BR3_MERIT_MISO_2U	Two unit outage - Start up of Ghent 1 and an outage of Brown 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_GH3_TC2_MERIT_MISO_2U	Two unit outage - Start up of Ghent 3 and an outage of Trimble Co 2, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
s_MC4_MERIT_MISO_BG12_PJM_2U	Two unit outage - Start up of Mill Creek 4,replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL) and an outage of Bluegrass 1 & 2, import from PJM (AP).
s_CR7_MERIT_MISO_BG12_PJM_2U	Two unit outage - Start up of Cane Run 7,replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL) and an outage of Bluegrass 1 & 2, import from PJM (AP).
CR7_PR_MERIT_MISO_2U	Two unit outage - Cane Run 7 and Paddys Run 13, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
CR7_BR3_MERIT_MISO_2U	Two unit outage - Cane Run 7 and Brown 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
Gh1_3_MERIT_MISO_2U	Two unit outage - Ghent 1 and Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).

Dispatch Code	Description
Gh4_3_MERIT_MISO_2U	Two unit outage - Ghent 3 and Ghent 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
Br3_Gh3_MERIT_MISO_2U	Two unit outage - Brown 3 and Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
Br3_Br6_MERIT_MISO_2U	Two unit outage - Brown 3 and Brown 6, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
Br7_Br6_MERIT_MISO_2U	Two unit outage - Brown 7 and Brown 6, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
MC4_MC3_MERIT_MISO_2U	Two unit outage - Mill Creek 4 and Mill Creek 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
TC2_TC1_MERIT_MISO_2U	Two unit outage - Trimble Co 2 and Trimble Co 1, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
CR7_TC2_MERIT_MISO_2U	Two unit outage - Cane Run 7 and Trimble Co 2, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
CR7_MC4_MERIT_MISO_2U	Two unit outage - Cane Run 7 and Mill Creek 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
MC4_TC2_MERIT_MISO_2U	Two unit outage - Trimble Co 2 and Mill Creek 4, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
Br3_Gh1_MERIT_MISO_2U	Two unit outage - Brown 3 and Ghent 1, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
TC2_GH3_MERIT_MISO_2U	Two unit outage - Trimble Co 2 and Ghent 3, replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL).
TC2_MERIT_MISO_BG12_PJM_2U	Two unit outage - Trimble Co 2,replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL) and an outage of Bluegrass 1 & 2, import from PJM (AP).
MC4_MERIT_MISO_BG12_PJM_2U	Two unit outage - Mill Creek 4,replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL) and an outage of Bluegrass 1 & 2, import from PJM (AP).
CR7_MERIT_MISO_BG12_PJM_2U	Two unit outage - Cane Run 7,replace with LGEE units greater than 50 MW in merit order and import from MISO (XEL) and an outage of Bluegrass 1 & 2, import from PJM (AP).
BG12_PJM	Outage Bluegrass units 1 & 2, replace with import from PJM (AP).
MBG_NITS	Maximize Bluegrass units, reduce import from PJM (AP).
MBR_NITS	Maximize Brown and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.

Dispatch Code	Description
MCR_NITS	Maximize Cane Run units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MDX_NITS	Maximize Dix Dam units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MGH_NITS	Maximize Ghent units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MHF_NITS	Maximize Haefling units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MMC_NITS	Maximize Mill Creek units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MOF_NITS	Maximize Ohio Falls units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MPD_NITS	Maximize Paducah Power units, reduce import from MISO (XEL).
MPR_NITS	Maximize Paddys Run units and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MPS_NITS	Maximize Paris units, reduce import from MISO (XEL).
MTC_NITS	Maximize Trimble Co Plant and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
MZR_NITS	Maximize Zorn and proportionally decrease generation at the remaining LG&E/KU affiliate generating plants.
PP12_MISO	Outage Paducah Power units and replace with import from MISO (XEL).
PP12_PJM	Outage Paducah Power units and replace with import from PJM (AP).
PP12_TVA	Outage Paducah Power units and replace with import from TVA.
BG12_BG3_PJM_2U	Two unit outage - Bluegrass 1&2 and Bluegrass 3, replace with import from PJM (AP).
BULLRUN1_S	Outage of TVA's Bull Run F 1 L, replacing with units in TVA and import from SOCO.
CANNELTON_W	Outage of SIGE's Cannelton Hydro units, replacing with import from MISO (XEL).
CLIFTY_N	Outage of OVEC's Clifty 7, replacing with import from PJM (AP).
CPR2_N	Outage of EKPC's Cooper 2, replacing with import from PJM (AP).
CRG2H_N	Outage of AEP's Clinch River 2 (H&L), replacing with import from PJM (AP).
EBND2_N	Outage of DEO&K's East Bend 2, replacing with import from PJM (AP).

Dispatch Code	Description
GALL2_W	Outage of DEI's Gallagher 2, replacing with import from MISO (XEL).
GALL4_W	Outage of DEI's Gallagher 4, replacing with import from MISO (XEL).
GALLATIN1_S	Outage of TVA's Gallatin 1, replacing with units in TVA and import from SOCO.
GIB2_W	Outage of DEI's Gibson 2, replacing with import from MISO (XEL).
GREEN1_W	Outage of BREC's Green 1, replacing with import from MISO (XEL).
INDDRV_N	Outage of AEP's Industrial Drive, replacing with import from PJM (AP).
JKCT9_N	Outage of EKPC's JK Smith 9, replacing with import from PJM (AP).
JOPPA2_W	Outage of EEI's Joppa 2, replacing with import from MISO (XEL).
JOPPA4_W	Outage of EEI's Joppa 4, replacing with import from MISO (XEL).
JOPPAG45_W	Outage of EEI's Joppa G 4&5, replacing with import from MISO (XEL).
KILLEN_N	Outage of Dayton PL Killen 2, replacing with import from PJM (AP).
KYGER_N	Outage of OVEC's Kyger 6, replacing with import from PJM (AP).
LAUREL_N	Outage of EKPC's Laurel Lake, replacing with import from PJM (AP).
LAWBG1_N	Outage of AEP's Lawrenceburg 1A/B/C, replacing with import from PJM (AP).
MERMOM_W	Outage of HE's Merom 2, replacing with import from MISO (XEL).
MFRT8_N	Outage of DEO&K's Miami Fort 8, replacing with import from PJM (AP).
NORRIS1_S	Outage of TVA's Norris, replacing with units in TVA and import from SOCO.
PARADISCT3S1_S	Outage of TVA's Paradise CT 3, replacing with units in TVA and import from SOCO.
RKG2_N	Outage of AEP's Rockport 1, replacing with import from PJM (AP).
SEQ2_S	Outage of TVA's Sequoyah 2, replacing with units in TVA and import from SOCO.
SHAWNEE2_S	Outage of TVA's Shawnee 2, replacing with units in TVA and import from SOCO.
SHAWNEE9_S	Outage of TVA's Shawnee 9, replacing with units in TVA and import from SOCO.
SPLK1_N	Outage of EKPC's Spurlock 1, replacing with import from PJM (AP).
SPLK2_N	Outage of EKPC's Spurlock 2, replacing with import from PJM (AP).
STUART_N	Outage of Dayton P&L Stuart, replacing with import from PJM (AP).
VACITY_SE	Outage of AEP's Virginia City, replacing with import from PJM (DVP).
WBNP1_S	Outage of TVA's Watts Bar 1, replacing with units in TVA and import from SOCO.
WILSON_W	Outage of BREC's Wilson, replacing with import from MISO (XEL).

Dispatch Code	Description
WOLFCR1_S	Outage of TVA's Wolf Creek, replacing with units in TVA and import from SOCO.
AMG2_N	Outage of AEP's John Amos #2, replacing with import from PJM (AP).
WTRG1S_N	Outage of AEP's Waterford 1S, replacing with import from PJM (AP).
V3-007_N	Outage of new PJM unit V3-007 1C, replacing with import from PJM (AP).
MFTGT1_N	Outage of DEO&K's Miami Fort GT1, replacing with import from PJM (AP).
Z1-079_N	Outage of new PJM unit Z1-079 CT & ST, replacing with import from PJM (AP).
AB1-169COP_N	Outage of new PJM unit ZAB1-169 C OP #1, replacing with import from PJM (AP).
JKCT1_N	Outage of EKPC's JK Smith 1, replacing with import from PJM (AP).
MADSN_W	Outage of DEI's Madison 1-8, replacing with import from MISO (XEL).
WHTLD_W	Outage of DEI's Wheatland #3 & #4, replacing with import from MISO (XEL).
CUL_G3_W	Outage of SIGE's FB Culley #3, replacing with import from MISO (XEL).
ABB_G2_W	Outage of SIGE's AB Brown #2, replacing with import from MISO (XEL).
PETERSBURG_W	Outage of IPL's Petersburg #4, replacing with import from MISO (XEL).
REID_W	Outage of BREC's Reid CT C, replacing with import from MISO (XEL).
SKILLMAN_W	Outage of BREC's Skillman #1, replacing with import from MISO (XEL).
SMITH_G_W	Outage of BREC's Smithland Hydro 1-3, replacing with import from MISO (XEL).
MARION_W	Outage of SIPC's Marion Generation Unit 1, replacing with import from MISO (XEL).
CUMBRL_S	Outage of TVA's Cumberland Fossil 1HL U1 & U2, replacing with units in TVA and import from SOCO.
SEQ1_S	Outage of TVA's Sequoyah 1, replacing with units in TVA and import from SOCO.
DOUGLAS_S	Outage of TVA's Douglas Hydro #1 & #2, replacing with units in TVA and import from SOCO.
J_SEVIER_S	Outage of TVA's John Sevier C3 & S4, replacing with units in TVA and import from SOCO.
BARKLEY_S	Outage of TVA's Barkley Hydro #3 & #4, replacing with units in TVA and import from SOCO.
CHEROKEE_S	Outage of TVA's Cherokee Hydro #1 & #2, replacing with units in TVA and import from SOCO.
KY_HYDRO_S	Outage of TVA's Kentucky Hydro #4 & #5, replacing with units in TVA and import from SOCO.
MARSHALL_S	Outage of TVA's Marshall Turbine 1-4, replacing with units in TVA and import from SOCO.

Appendix C: Divergent Contingencies

There were numerous contingency and dispatch conditions for which a convergent solution could not be obtained with switched shunts enabled. For these contingencies, a solution was attempted with switched shunts locked. If constraints were found to exist for any of these contingencies using the locked switched shunts solution method, further analysis was performed. For those contingencies and dispatches for which a solution could not be reached even with locked switched shunts, alternative methods were implemented as stated in Table C-1.

Table C-1
Solution Techniques Applied to Solve the Remaining Divergent Contingencies and Dispatches

Year/Season	Dispatches	Contingencies	Solution
None	None	None	None

Appendix D: Powerflow Model Detailed Analysis

Network Analysis

The LG&E and KU GI 2019-0129 thermal constraints due to the subject request are given in Table D-1 and Table D-2. These constraints were found for many dispatch/contingency combinations in both NRIS and ERIS Analyses. Only the result with the highest post project loading for each facility is shown in Table D-1 and Table D-2.

Table D-1
GI 2019-029 NRIS Thermal Constraints

Year / Season / Service Type	Dispatch	Facility	Rating	Pre Project	Post Project		DF	Contingency
				MVA	MVA	%		
2023OP NRIS	mtc_nits	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	81.61	122.84	125.35	41%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	mgh_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	98	63.84	104.24	106.37	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	170.44	241.04	126.20	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	76.67	116.46	118.84	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	60.37	98.31	114.31	38%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO 4CENT HARDIN138.00 1	227	149.07	227.05	100.02	78%	None
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	161.87	241.71	116.21	80%	None
2023S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160.20	239.80	115.29	80%	None
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	149.11	217.91	114.09	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	76.06	116.05	118.42	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	59.49	97.52	113.40	38%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	159.88	241.58	116.14	82%	None

Year / Season / Service Type	Dispatch	Facility	Rating	Pre Project	Post Project		DF	Contingency
				MVA	MVA	%		
2030S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	158.00	239.57	115.18	82%	None
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	150.11	218.66	114.48	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

Table D-2
GI 2019-029 ERIS Thermal Constraints

Year / Season / Service Type	Dispatch	Facility	Rating	Pre Project	Post Project		DF	Contingency
				MVA	MVA	%		
2023OP ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	75.05	115.25	117.60	40%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	172.35	243.16	127.31	71%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	71.22	110.30	112.55	39%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	54.96	92.21	107.22	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	155.13	234.01	112.50	79%	None
2023S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	154.00	232.87	111.96	79%	None
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	147.72	216.73	113.47	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	70.05	109.30	111.53	39%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	53.51	90.81	105.59	37%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152.61	233.02	112.03	80%	None
2030S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152.00	232.01	111.54	80%	None
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148.47	217.30	113.77	69%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1

No Off Peak or Summer, NRIS or ERIS, system intact or contingency, voltage constraints due to the subject request were found.

Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023

Table D-3
Limited Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023 NRIS Results

Model	Dispatch	Facility	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
				MVA	%	MVA	%	MVA	%	
2023OP NRIS	mtc_nits	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	82	83%	123	125%	118	121%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	mtc_nits	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	98	64	65%	104	106%	100	102%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP NRIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	170	89%	241	126%	241	126%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	77	78%	116	119%	113	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	60	70%	98	114%	95	110%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	149	78%	218	114%	219	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S NRIS	mtc_nits	**4BLACKBRANCH138.00 TO 4CENT HARDIN138.00 1**	227	149	66%	227	100%	223	**98%**	None
2023S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	162	78%	242	116%	238	114%	None
2023S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160	77%	236	114%	236	114%	None
2030S NRIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	76	78%	116	118%	112	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	59	69%	98	113%	94	109%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S NRIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	150	79%	219	114%	219	115%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S NRIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	160	77%	242	116%	238	114%	None
2030S NRIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	158	76%	236	113%	236	113%	None

Table D-4
Limited Sensitivity to Withdrawal of GI-2019-020 and GI-2019-023 ERIS Results

Model	Dispatch	Facility	Rating	Pre Project w/ 020 and 023		Post Project w/ 020 and 023		Post Project w/o 020 and 023		Contingency
				MVA	%	MVA	%	MVA	%	
2023OP ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	75	77%	115	118%	113	115%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023OP ERIS	paradisct3s1_s	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	172	90%	243	127%	243	127%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	71	73%	110	113%	108	110%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	55	64%	92	107%	90	104%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2023S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148	77%	217	113%	217	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2023S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	155	75%	234	113%	231	111%	None
2023S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	154	74%	230	111%	230	111%	None
2030S ERIS	wbnp1_s	2CENT HARDIN69.000 TO 2KARGLE 69.000 1	98	70	71%	109	112%	107	109%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wbnp1_s	2ETOWN KU 69.000 TO 2KARGLE 69.000 1	86	54	62%	91	106%	88	103%	OPEN [4HARDIN CO 138.00] [4CENT HARDIN138.00] CKT 1
2030S ERIS	wilson_w	4HARDINSBURG138.00 TO 4N.HARD 138.00 1	191	148	78%	217	114%	218	114%	OPEN [4BLACKBRANCH138.00] [GI2019029P 138.00] CKT 1
2030S ERIS	mtc_nits	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	153	73%	233	112%	230	111%	None
2030S ERIS	Base Dispatch	4BLACKBRANCH138.00 TO GI2019029P 138.00 1	208	152	73%	229	110%	229	110%	None

Flowgate Analysis

Table D-5
NRIS Flowgate Detailed Analysis Results

Year/ Season	Constrained Interface					Pre Project	Post Project	DF	Loading
	NERC Id	NERC Name	OWNER	Type	Rating	MW	MW		
2023OP	1023	VOLPHBJEFROC	TVA	OTDF	1900	1334	1336	1%	70%
2023OP	1024	VOLPHBCONMOS	TVA	OTDF	1900	1414	1415	1%	74%
2023OP	1095	SMIXFRWILDAV	OMU	OTDF	308	-99	-100	-1%	-33%
2023OP	1613	VOLPHB__PTDF	TVA	PTDF	1900	1237	1238	1%	65%
2023OP	1644	BLLVOL__PTDF	TVA	PTDF	2589	1285	1286	1%	50%
2023OP	2047	GIBPETGIBBDF	MISO	OTDF	1195	888	891	3%	75%
2023OP	2614	BULVOLWBNVOL	TVA	OTDF	2756	1838	1837	0%	67%
2023OP	2837	WILGRVMATWIL	MISO	OTDF	558	77	76	-1%	14%
2023OP	2973	SMIXFMHBGHCO	OMU	OTDF	308	3	4	2%	1%
2023OP	3322	4CL4NH4CL4HA	MISO	OTDF	191	6	-2	-9%	-1%
2023OP	17564	VOLPHIMOUNTA	TVA	OTDF	1900	1232	1233	1%	65%
2023OP	17884	VOLPHBCULWYO	TVA	OTDF	1900	1271	1273	1%	67%
2023OP	23687	VOLPHIGAVIN2	TVA	OTDF	1900	1233	1234	1%	65%
2023OP	24583	VOLPHIANTJAC	TVA	OTDF	1900	1253	1255	1%	66%
2023OP	25987	PINPINSULBFD	TVA	OTDF	601	169	168	-1%	28%
2023OP	25989	PINPINKAMBEL	TVA	OTDF	601	129	127	-2%	21%
2023OP	26295	JOPJGTJOPGRA	MISO	OTDF	335	211	211	0%	63%
2023S	1023	VOLPHBJEFROC	TVA	OTDF	1900	1339	1340	1%	71%
2023S	1024	VOLPHBCONMOS	TVA	OTDF	1900	1418	1419	1%	75%
2023S	1095	SMIXFRWILDAV	OMU	OTDF	308	-48	-49	-1%	-16%
2023S	1613	VOLPHB__PTDF	TVA	PTDF	1900	1242	1243	1%	65%
2023S	1644	BLLVOL__PTDF	TVA	PTDF	2756	1291	1292	1%	47%
2023S	2047	GIBPETGIBBDF	MISO	OTDF	1195	851	855	4%	72%
2023S	2614	BULVOLWBNVOL	TVA	OTDF	2598	1849	1851	1%	71%
2023S	2837	WILGRVMATWIL	MISO	OTDF	558	181	178	-3%	32%
2023S	2973	SMIXFMHBGHCO	OMU	OTDF	308	-46	-44	2%	-14%
2023S	3322	4CL4NH4CL4HA	MISO	OTDF	191	-20	-28	-9%	-15%
2023S	17564	VOLPHIMOUNTA	TVA	OTDF	1900	1238	1239	1%	65%
2023S	17884	VOLPHBCULWYO	TVA	OTDF	1900	1278	1279	1%	67%
2023S	23687	VOLPHIGAVIN2	TVA	OTDF	1900	1238	1239	1%	65%
2023S	24583	VOLPHIANTJAC	TVA	OTDF	1900	1257	1258	1%	66%
2023S	25987	PINPINSULBFD	TVA	OTDF	580	196	195	-1%	34%
2023S	25989	PINPINKAMBEL	TVA	OTDF	580	166	165	-2%	28%
2023S	26295	JOPJGTJOPGRA	MISO	OTDF	335	172	172	0%	51%
2030S	1023	VOLPHBJEFROC	TVA	OTDF	1900	1231	1232	1%	65%

Year/ Season	Constrained Interface					Pre Project	Post Project	DF	Loading
	NERC Id	NERC Name	OWNER	Type	Rating	MW	MW		
2030S	1024	VOLPHBCONMOS	TVA	OTDF	1900	1302	1303	1%	69%
2030S	1095	SMIXFRWILDAV	OMU	OTDF	308	-46	-47	-1%	-15%
2030S	1613	VOLPHB__PTDF	TVA	PTDF	1900	1137	1138	1%	60%
2030S	1644	BLLVOL__PTDF	TVA	PTDF	2756	1173	1173	1%	43%
2030S	2047	GIBPETGIBBDF	MISO	OTDF	1195	840	843	3%	71%
2030S	2614	BULVOLWBNVOL	TVA	OTDF	2598	1783	1784	1%	69%
2030S	2837	WILGRVMATWIL	MISO	OTDF	558	163	160	-3%	29%
2030S	2973	SMIXFMHBGHCO	OMU	OTDF	308	-46	-44	2%	-14%
2030S	3322	4CL4NH4CL4HA	MISO	OTDF	191	-20	-28	-9%	-15%
2030S	17564	VOLPHIMOUNTA	TVA	OTDF	1900	1132	1133	1%	60%
2030S	17884	VOLPHBCULWYO	TVA	OTDF	1900	1173	1174	1%	62%
2030S	23687	VOLPHIGAVIN2	TVA	OTDF	1900	1132	1134	1%	60%
2030S	24583	VOLPHIANTJAC	TVA	OTDF	1900	1178	1179	1%	62%
2030S	25987	PINPINSULBFD	TVA	OTDF	580	64	63	-1%	11%
2030S	25989	PINPINKAMBEL	TVA	OTDF	580	67	65	-2%	11%
2030S	26295	JOPJGTJOPGRA	MISO	OTDF	335	178	178	0%	53%

Appendix E: Powerflow Model Documentation

Table E-1
Selected Generation Modeling in the GI-2019-029
Off Peak and Summer NRIS and ERIS Pre/Post Models

Bus Number	Bus Name	Id	Area Name	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	423	423	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	521	521	526	526	526	526
325093	1CANERUN7CT118.000	71	LGEE	235	235	232	232	232	232
325094	1CANERUN7CT218.000	72	LGEE	235	235	232	232	232	232
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
253625	10CAN_G1 6.9000	1	SIGE	30	30	30	30	30	30
253626	10CAN_G2 6.9000	2	SIGE	30	30	30	30	30	30
253627	10CAN_G3 6.9000	3	SIGE	30	30	30	30	30	30

Table E-2
Selected Generation Modeling Area 363 in the GI-2019-029
Off Peak and Summer NRIS Pre Models

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324002	1BROWN 3 24.000	3	LGEE	0	456	183	459	183	459
324003	1BROWN 5 13.800	5	LGEE	0	121	0	131	0	131
324004	1BROWN 6 18.000	6	LGEE	0	158	0	155	0	155
324005	1BROWN 7 18.000	7	LGEE	0	158	0	154	0	154
324006	1BROWN 8 13.800	8	LGEE	0	119	0	122	0	122
324007	1BROWN 9 13.800	9	LGEE	0	119	0	122	0	122
324008	1BROWN 10 13.800	10	LGEE	0	119	0	122	0	122
324009	1BROWN 11 13.800	11	LGEE	0	119	0	122	0	122
324014	1DIX DAM 1 13.200	1	LGEE	11	11	11	11	11	11
324015	1DIX DAM 2 13.200	2	LGEE	11	11	11	11	11	11
324016	1DIX DAM 3 13.200	3	LGEE	11	11	11	11	11	11
324017	1GHENT 1 18.000	1	LGEE	0	520	526	526	526	526
324018	1GHENT 2 22.000	2	LGEE	0	520	530	530	530	530
324019	1GHENT 3 22.000	3	LGEE	0	528	486	538	479	538
324020	1GHENT 4 22.000	4	LGEE	0	525	538	538	538	538
324023	1HAEFLING 13.800	1	LGEE	0	14	0	13	0	13
324023	1HAEFLING 13.800	2	LGEE	0	14	0	13	0	13
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	423	423	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	521	521	526	526	526	526
324031	1PADDY RN 1316.000	13	LGEE	0	162	0	152	0	152

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324034	1TRIM CO 1 22.000	1	LGEE	533	552	530	530	530	530
324035	1TRIM CO 2 24.000	2	LGEE	469	817	781	781	781	781
324036	1TRIM CO 5 18.000	5	LGEE	0	170	81	160	81	160
324037	1TRIM CO 6 18.000	6	LGEE	0	170	0	171	0	171
324038	1TRIM CO 7 18.000	7	LGEE	0	170	0	163	0	163
324039	1TRIM CO 8 18.000	8	LGEE	0	170	0	160	0	160
324040	1TRIM CO 9 18.000	9	LGEE	0	170	0	166	0	166
324041	1TRIM CO 10 18.000	10	LGEE	0	170	0	164	0	164
324043	1ZORN 13.800	1	LGEE	0	15	0	14	0	14
324044	1BLUEGRASS 118.000	1	LGEE	0	166	166	166	166	166
324045	1BLUEGRASS 218.000	2	LGEE	0	166	166	166	166	166
324046	1BLUEGRASS 318.000	3	LGEE	0	166	166	166	166	166
324052	1LOCK 7 2.4000	1	LGEE	2	2	2	2	2	2
324234	1OHIO FALL 114.000	1	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	2	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	3	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	4	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	5	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	6	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	7	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	8	LGEE	13	13	9	9	9	9
324677	2PARIS 12 69.000	1	LGEE	0	11	0	11	0	11
324697	1KMPA PAD2 13.800	2	LGEE	0	61	43	54	20	54
324933	1KMPA PAD1 13.800	1	LGEE	0	61	28	54	20	54
325012	1BROWN SOLAR13.200	S1	LGEE	10	10	8	8	8	8
325029	G2017-02 GEN0.6450	1	LGEE	86	86	69	86	69	86
325030	G2017-03 GEN0.5750	1	LGEE	37	35	29	35	29	35
325093	1CANERUN7CT118.000	71	LGEE	235	235	232	232	232	232
325094	1CANERUN7CT218.000	72	LGEE	235	235	232	232	232	232
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
326514	1PADDY RN 1114.000	11	LGEE	0	13	0	12	0	12
326515	1PADDY RN 1214.000	12	LGEE	0	26	0	23	0	23
326541	2EKPC OFFICE69.000	P1	LGEE	9	9	7	9	7	9
911005	GI2019-004GS0.6450	1	LGEE	264	264	211	264	211	264
911008	GI2019-004GB0.6450	2	LGEE	-57	65	-6	65	-6	65
990105	GI2019-003GS0.6450	1	LGEE	163	163	130	163	130	163
990108	GI2019-003GB0.6450	2	LGEE	-37	38	-6	38	-6	38
991044	2019-GI002 G0.5500	1	LGEE	NA	NA	84	125	84	125
991160	2019-GI001 G0.6600	1	LGEE	NA	NA	NA	NA	89	112
999100	2019-GI008 G0.6600	1	LGEE	101	110	81	110	81	110
999104	2019-GI015 G0.7000	1	LGEE	101	104	81	104	81	104

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
999119	2019-GI020 G0.7000	1	LGEE	86	88	69	88	69	88
999139	2019-GI023 G0.7000	1	LGEE	152	153	121	153	121	153
999144	2019-GI025G 0.6000	1	LGEE	100	100	80	100	80	100

Table E-3
Selected Generation Modeling Area 363 in the GI-2019-029
Off Peak and Summer ERIS Pre Models

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324002	1BROWN 3 24.000	3	LGEE	0	456	459	459	459	459
324003	1BROWN 5 13.800	5	LGEE	0	121	0	131	0	131
324004	1BROWN 6 18.000	6	LGEE	0	158	0	155	0	155
324005	1BROWN 7 18.000	7	LGEE	0	158	0	154	0	154
324006	1BROWN 8 13.800	8	LGEE	0	119	0	122	0	122
324007	1BROWN 9 13.800	9	LGEE	0	119	0	122	0	122
324008	1BROWN 10 13.800	10	LGEE	0	119	0	122	0	122
324009	1BROWN 11 13.800	11	LGEE	0	119	0	122	0	122
324014	1DIX DAM 1 13.200	1	LGEE	11	11	11	11	11	11
324015	1DIX DAM 2 13.200	2	LGEE	11	11	11	11	11	11
324016	1DIX DAM 3 13.200	3	LGEE	11	11	11	11	11	11
324017	1GHENT 1 18.000	1	LGEE	0	520	526	526	526	526
324018	1GHENT 2 22.000	2	LGEE	0	520	530	530	530	530
324019	1GHENT 3 22.000	3	LGEE	0	528	538	538	538	538
324020	1GHENT 4 22.000	4	LGEE	0	525	538	538	538	538
324023	1HAEFLING 13.800	1	LGEE	0	14	0	13	0	13
324023	1HAEFLING 13.800	2	LGEE	0	14	0	13	0	13
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	423	423	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	521	521	526	526	526	526
324031	1PADDY RN 1316.000	13	LGEE	0	162	0	152	0	152
324034	1TRIM CO 1 22.000	1	LGEE	533	552	530	530	530	530
324035	1TRIM CO 2 24.000	2	LGEE	469	817	781	781	781	781
324036	1TRIM CO 5 18.000	5	LGEE	0	170	99	160	160	160
324037	1TRIM CO 6 18.000	6	LGEE	0	170	81	171	103	171
324038	1TRIM CO 7 18.000	7	LGEE	0	170	81	163	81	163
324039	1TRIM CO 8 18.000	8	LGEE	0	170	81	160	81	160
324040	1TRIM CO 9 18.000	9	LGEE	0	170	81	166	81	166
324041	1TRIM CO 10 18.000	10	LGEE	0	170	81	164	81	164
324043	1ZORN 13.800	1	LGEE	0	15	0	14	0	14
324044	1BLUEGRASS 118.000	1	LGEE	0	166	166	166	166	166
324045	1BLUEGRASS 218.000	2	LGEE	0	166	166	166	166	166
324046	1BLUEGRASS 318.000	3	LGEE	0	166	166	166	166	166
324052	1LOCK 7 2.4000	1	LGEE	2	2	2	2	2	2
324234	1OHIO FALL 114.000	1	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	2	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	3	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	4	LGEE	13	13	9	9	9	9

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324235	1OHIO FALL 214.000	5	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	6	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	7	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	8	LGEE	13	13	9	9	9	9
324677	2PARIS 12 69.000	1	LGEE	0	11	0	11	0	11
324697	1KMPA PAD2 13.800	2	LGEE	0	61	43	54	20	54
324933	1KMPA PAD1 13.800	1	LGEE	0	61	28	54	20	54
325012	1BROWN SOLAR13.200	S1	LGEE	10	10	8	8	8	8
325029	G2017-02 GEN0.6450	1	LGEE	86	86	69	86	69	86
325030	G2017-03 GEN0.5750	1	LGEE	37	35	29	35	29	35
325093	1CANERUN7CT118.000	71	LGEE	235	235	232	232	232	232
325094	1CANERUN7CT218.000	72	LGEE	235	235	232	232	232	232
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
326514	1PADDY RN 1114.000	11	LGEE	0	13	0	12	0	12
326515	1PADDY RN 1214.000	12	LGEE	0	26	0	23	0	23
326541	2EKPC OFFICE69.000	P1	LGEE	9	9	7	9	7	9
911005	GI2019-004GS0.6450	1	LGEE	264	264	211	264	211	264
911008	GI2019-004GB0.6450	2	LGEE	-57	65	-6	65	-6	65
990105	GI2019-003GS0.6450	1	LGEE	163	163	130	163	130	163
990108	GI2019-003GB0.6450	2	LGEE	-37	38	-6	38	-6	38
991044	2019-GI002 G0.5500	1	LGEE	NA	NA	84	125	84	125
991160	2019-GI001 G0.6600	1	LGEE	NA	NA	NA	NA	89	112
999100	2019-GI008 G0.6600	1	LGEE	101	110	81	110	81	110
999104	2019-GI015 G0.7000	1	LGEE	101	104	81	104	81	104
999119	2019-GI020 G0.7000	1	LGEE	86	88	69	88	69	88
999139	2019-GI023 G0.7000	1	LGEE	152	153	121	153	121	153
999144	2019-GI025G 0.6000	1	LGEE	100	100	80	100	80	100

Table E-4
Selected Generation Modeling Area 363 in the GI-2019-029 Off Peak and Summer NRIS Post Models

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324002	1BROWN 3 24.000	3	LGEE	0	456	183	459	183	459
324003	1BROWN 5 13.800	5	LGEE	0	121	0	131	0	131
324004	1BROWN 6 18.000	6	LGEE	0	158	0	155	0	155
324005	1BROWN 7 18.000	7	LGEE	0	158	0	154	0	154
324006	1BROWN 8 13.800	8	LGEE	0	119	0	122	0	122
324007	1BROWN 9 13.800	9	LGEE	0	119	0	122	0	122
324008	1BROWN 10 13.800	10	LGEE	0	119	0	122	0	122
324009	1BROWN 11 13.800	11	LGEE	0	119	0	122	0	122
324014	1DIX DAM 1 13.200	1	LGEE	11	11	11	11	11	11

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324015	1DIX DAM 2 13.200	2	LGEE	11	11	11	11	11	11
324016	1DIX DAM 3 13.200	3	LGEE	11	11	11	11	11	11
324017	1GHENT 1 18.000	1	LGEE	0	520	526	526	526	526
324018	1GHENT 2 22.000	2	LGEE	0	520	530	530	530	530
324019	1GHENT 3 22.000	3	LGEE	0	528	464	538	457	538
324020	1GHENT 4 22.000	4	LGEE	0	525	538	538	538	538
324023	1HAEFLING 13.800	1	LGEE	0	14	0	13	0	13
324023	1HAEFLING 13.800	2	LGEE	0	14	0	13	0	13
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	423	423	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	521	521	526	526	526	526
324031	1PADDY RN 1316.000	13	LGEE	0	162	0	152	0	152
324034	1TRIM CO 1 22.000	1	LGEE	432	552	530	530	530	530
324035	1TRIM CO 2 24.000	2	LGEE	469	817	781	781	781	781
324036	1TRIM CO 5 18.000	5	LGEE	0	170	0	160	0	160
324037	1TRIM CO 6 18.000	6	LGEE	0	170	0	171	0	171
324038	1TRIM CO 7 18.000	7	LGEE	0	170	0	163	0	163
324039	1TRIM CO 8 18.000	8	LGEE	0	170	0	160	0	160
324040	1TRIM CO 9 18.000	9	LGEE	0	170	0	166	0	166
324041	1TRIM CO 10 18.000	10	LGEE	0	170	0	164	0	164
324043	1ZORN 13.800	1	LGEE	0	15	0	14	0	14
324044	1BLUEGRASS 118.000	1	LGEE	0	166	166	166	166	166
324045	1BLUEGRASS 218.000	2	LGEE	0	166	166	166	166	166
324046	1BLUEGRASS 318.000	3	LGEE	0	166	166	166	166	166
324052	1LOCK 7 2.4000	1	LGEE	2	2	2	2	2	2
324234	1OHIO FALL 114.000	1	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	2	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	3	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	4	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	5	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	6	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	7	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	8	LGEE	13	13	9	9	9	9
324677	2PARIS 12 69.000	1	LGEE	0	11	0	11	0	11
324697	1KMPA PAD2 13.800	2	LGEE	0	61	43	54	20	54
324933	1KMPA PAD1 13.800	1	LGEE	0	61	28	54	20	54
325012	1BROWN SOLAR13.200	S1	LGEE	10	10	8	8	8	8
325029	G2017-02 GEN0.6450	1	LGEE	86	86	69	86	69	86
325030	G2017-03 GEN0.5750	1	LGEE	37	35	29	35	29	35
325093	1CANERUN7CT118.000	71	LGEE	235	235	232	232	232	232

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
325094	1CANERUN7CT218.000	72	LGEE	235	235	232	232	232	232
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
326514	1PADDY RN 1114.000	11	LGEE	0	13	0	12	0	12
326515	1PADDY RN 1214.000	12	LGEE	0	26	0	23	0	23
326541	2EKPC OFFICE69.000	P1	LGEE	9	9	7	9	7	9
911005	GI2019-004GS0.6450	1	LGEE	264	264	211	264	211	264
911008	GI2019-004GB0.6450	2	LGEE	-57	65	-6	65	-6	65
990105	GI2019-003GS0.6450	1	LGEE	163	163	130	163	130	163
990108	GI2019-003GB0.6450	2	LGEE	-37	38	-6	38	-6	38
991044	2019-GI002 G0.5500	1	LGEE	NA	NA	84	125	84	125
991160	2019-GI001 G0.6600	1	LGEE	NA	NA	NA	NA	89	112
999100	2019-GI008 G0.6600	1	LGEE	101	110	81	110	81	110
999104	2019-GI015 G0.7000	1	LGEE	101	104	81	104	81	104
999119	2019-GI020 G0.7000	1	LGEE	86	88	69	88	69	88
999129	GI-2019-029S0.5500	1	LGEE	101	114	102	114	102	114
999139	2019-GI023 G0.7000	1	LGEE	152	153	121	153	121	153
999144	2019-GI025G 0.6000	1	LGEE	100	100	80	100	80	100

Table E-5
Selected Generation Modeling Area 363 in the GI-2019-029 Off Peak and Summer ERIS Post Models

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324002	1BROWN 3 24.000	3	LGEE	0	456	459	459	459	459
324003	1BROWN 5 13.800	5	LGEE	0	121	0	131	0	131
324004	1BROWN 6 18.000	6	LGEE	0	158	0	155	0	155
324005	1BROWN 7 18.000	7	LGEE	0	158	0	154	0	154
324006	1BROWN 8 13.800	8	LGEE	0	119	0	122	0	122
324007	1BROWN 9 13.800	9	LGEE	0	119	0	122	0	122
324008	1BROWN 10 13.800	10	LGEE	0	119	0	122	0	122
324009	1BROWN 11 13.800	11	LGEE	0	119	0	122	0	122
324014	1DIX DAM 1 13.200	1	LGEE	11	11	11	11	11	11
324015	1DIX DAM 2 13.200	2	LGEE	11	11	11	11	11	11
324016	1DIX DAM 3 13.200	3	LGEE	11	11	11	11	11	11
324017	1GHENT 1 18.000	1	LGEE	0	520	526	526	526	526
324018	1GHENT 2 22.000	2	LGEE	312	520	530	530	530	530
324019	1GHENT 3 22.000	3	LGEE	0	528	538	538	538	538
324020	1GHENT 4 22.000	4	LGEE	262	525	538	538	538	538
324023	1HAEFLING 13.800	1	LGEE	0	14	0	13	0	13
324023	1HAEFLING 13.800	2	LGEE	0	14	0	13	0	13
324024	1MILL CRK 1 22.000	1	LGEE	330	330	333	333	333	333
324025	1MILL CRK 2 22.000	2	LGEE	330	330	336	336	336	336
324026	1MILL CRK 3 22.000	3	LGEE	423	423	425	425	425	425
324027	1MILL CRK 4 22.000	4	LGEE	521	521	526	526	526	526
324031	1PADDY RN 1316.000	13	LGEE	0	162	0	152	0	152
324034	1TRIM CO 1 22.000	1	LGEE	552	552	530	530	530	530
324035	1TRIM CO 2 24.000	2	LGEE	808	817	781	781	781	781
324036	1TRIM CO 5 18.000	5	LGEE	0	170	99	160	160	160
324037	1TRIM CO 6 18.000	6	LGEE	0	170	81	171	103	171
324038	1TRIM CO 7 18.000	7	LGEE	0	170	81	163	81	163
324039	1TRIM CO 8 18.000	8	LGEE	0	170	81	160	81	160
324040	1TRIM CO 9 18.000	9	LGEE	0	170	81	166	81	166
324041	1TRIM CO 10 18.000	10	LGEE	0	170	81	164	81	164
324043	1ZORN 13.800	1	LGEE	0	15	0	14	0	14
324044	1BLUEGRASS 118.000	1	LGEE	0	166	166	166	166	166
324045	1BLUEGRASS 218.000	2	LGEE	0	166	166	166	166	166
324046	1BLUEGRASS 318.000	3	LGEE	0	166	166	166	166	166
324052	1LOCK 7 2.4000	1	LGEE	2	2	2	2	2	2
324234	1OHIO FALL 114.000	1	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	2	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	3	LGEE	13	13	9	9	9	9
324234	1OHIO FALL 114.000	4	LGEE	13	13	9	9	9	9

Bus Number	Bus Name	Id	Area	2023OP Pgen	2023OP Pmax	2023S Pgen	2023S Pmax	2030S Pgen	2030S Pmax
324235	1OHIO FALL 214.000	5	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	6	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	7	LGEE	13	13	9	9	9	9
324235	1OHIO FALL 214.000	8	LGEE	13	13	9	9	9	9
324677	2PARIS 12 69.000	1	LGEE	0	11	0	11	0	11
324697	1KMPA PAD2 13.800	2	LGEE	0	61	43	54	20	54
324933	1KMPA PAD1 13.800	1	LGEE	0	61	28	54	20	54
325012	1BROWN SOLAR13.200	S1	LGEE	10	10	8	8	8	8
325029	G2017-02 GEN0.6450	1	LGEE	86	86	69	86	69	86
325030	G2017-03 GEN0.5750	1	LGEE	37	35	29	35	29	35
325093	1CANERUN7CT118.000	71	LGEE	235	235	232	232	232	232
325094	1CANERUN7CT218.000	72	LGEE	235	235	232	232	232	232
325095	1CANERUN7ST 18.000	7S	LGEE	235	235	241	241	241	241
326514	1PADDY RN 1114.000	11	LGEE	0	13	0	12	0	12
326515	1PADDY RN 1214.000	12	LGEE	0	26	0	23	0	23
326541	2EKPC OFFICE69.000	P1	LGEE	9	9	7	9	7	9
911005	GI2019-004GS0.6450	1	LGEE	264	264	211	264	211	264
911008	GI2019-004GB0.6450	2	LGEE	-57	65	-6	65	-6	65
990105	GI2019-003GS0.6450	1	LGEE	163	163	130	163	130	163
990108	GI2019-003GB0.6450	2	LGEE	-37	38	-6	38	-6	38
991044	2019-GI002 G0.5500	1	LGEE	NA	NA	84	125	84	125
991160	2019-GI001 G0.6600	1	LGEE	NA	NA	NA	NA	89	112
999100	2019-GI008 G0.6600	1	LGEE	101	110	81	110	81	110
999104	2019-GI015 G0.7000	1	LGEE	101	104	81	104	81	104
999119	2019-GI020 G0.7000	1	LGEE	8l6	88	69	88	69	88
999129	GI-2019-029S0.5500	1	LGEE	101	114	101	114	102	114
999139	2019-GI023 G0.7000	1	LGEE	152	153	121	153	121	153
999144	2019-GI025G 0.6000	1	LGEE	100	100	80	100	80	100

Table E-6
Selected Generation Modeling in the Post GI-2019-029 Stability Models

Bus Number	Bus Name	Id	2021S Pgen	2021S Pmax	2021SM Pgen	2021SM Pmax	2024 LL Pgen	2024 LL Pmax	2029S Pgen	2029S Pmax
324024	1MILL CRK 1 22.000	1	327	327	343	343	327	327	327	327
324025	1MILL CRK 2 22.000	2	331	331	341	341	331	331	331	331
324026	1MILL CRK 3 22.000	3	422	422	445	445	422	422	422	422
324027	1MILL CRK 4 22.000	4	514	514	541	541	514	514	514	514
325093	1CANERUN7CT118.000	71	204	204	230	230	179	204	204	204
325094	1CANERUN7CT218.000	72	204	204	230	230	178	204	204	204
325095	1CANERUN7ST 18.000	7S	231	231	231	231	193	231	231	231
253625	10CAN_G1 6.9000	1	30	30	26	30	30	30	30	30
253626	10CAN_G2 6.9000	2	30	30	30	30	30	30	30	30
253627	10CAN_G3 6.9000	3	30	30	30	30	30	30	30	30
324000	1BROWN 1 13.800	1	0	0	113	113	0	0	0	0
324001	1BROWN 2 18.000	2	0	0	180	180	0	0	0	0
324002	1BROWN 3 24.000	3	454	454	454	454	0	454	454	454
324003	1BROWN 5 13.800	5	0	104	141	141	0	104	0	104
324004	1BROWN 6 18.000	6	16	146	177	177	0	146	16	146
324005	1BROWN 7 18.000	7	105	145	177	177	0	145	105	145
324006	1BROWN 8 13.800	8	0	98	140	140	0	98	0	98
324007	1BROWN 9 13.800	9	0	89	140	140	0	89	0	89
324008	1BROWN 10 13.800	10	0	87	140	140	0	87	0	87
324009	1BROWN 11 13.800	11	0	98	140	140	0	98	0	98
324013	1CANE RN 11 14.000	11	0	14	16	16	0	14	0	14
324014	1DIX DAM 1 13.200	1	11	11	11	11	11	11	11	11
324015	1DIX DAM 2 13.200	2	11	11	11	11	11	11	11	11
324016	1DIX DAM 3 13.200	3	11	11	11	11	11	11	11	11
324017	1GHENT 1 18.000	1	520	520	545	545	0	520	520	520
324018	1GHENT 2 22.000	2	533	533	543	543	0	533	533	533
324019	1GHENT 3 22.000	3	526	526	547	547	0	526	526	526
324020	1GHENT 4 22.000	4	513	513	550	550	0	513	513	513
324023	1HAEFLING 13.800	1	0	12	18	18	0	12	0	12
324023	1HAEFLING 13.800	2	0	12	18	18	0	12	0	12
324031	1PADDY RN 1316.000	13	100	143	175	175	0	143	100	143
324034	1TRIM CO 1 22.000	1	528	528	557	557	280	528	528	528
324035	1TRIM CO 2 24.000	2	777	777	832	832	432	777	777	777
324036	1TRIM CO 5 18.000	5	151	151	180	180	0	151	151	151
324037	1TRIM CO 6 18.000	6	151	151	180	180	0	151	151	151
324038	1TRIM CO 7 18.000	7	149	149	180	180	0	149	116	149
324039	1TRIM CO 8 18.000	8	96	148	180	180	0	148	90	148
324040	1TRIM CO 9 18.000	9	85	148	180	180	0	148	85	148
324041	1TRIM CO 10 18.000	10	86	153	178	180	0	153	86	153

Bus Number	Bus Name	Id	2021S Pgen	2021S Pmax	2021SM Pgen	2021SM Pmax	2024 LL Pgen	2024 LL Pmax	2029S Pgen	2029S Pmax
324043	2ZORN 69.000	1	0	14	16	16	0	14	0	14
324044	1BLUEGRASS 118.000	1	166	166	217	228	0	166	166	166
324045	1BLUEGRASS 218.000	2	166	166	217	228	0	166	166	166
324046	1BLUEGRASS 318.000	3	166	166	217	228	0	166	166	166
324234	1OHIO FALL 114.000	1	8	8	13	13	8	8	8	8
324234	1OHIO FALL 114.000	2	8	8	13	13	8	8	8	8
324234	1OHIO FALL 114.000	3	8	8	13	13	8	8	8	8
324234	1OHIO FALL 114.000	4	8	8	13	13	8	8	8	8
324235	1OHIO FALL 214.000	5	8	8	13	13	8	8	8	8
324235	1OHIO FALL 214.000	6	8	8	13	13	8	8	8	8
324235	1OHIO FALL 214.000	7	8	8	13	13	8	8	8	8
324235	1OHIO FALL 214.000	8	8	8	13	13	8	8	8	8
324697	1KMPA PAD2 13.800	2	27	54	62	62	0	54	47	54
324933	1KMPA PAD1 13.800	1	27	54	62	62	0	54	47	54
325012	1BROWN SOLAR13.200	S1	8	8	10	10	8	8	8	8
326514	1PADDY RN 1114.000	11	0	12	16	16	0	12	0	12
326515	1PADDY RN 1214.000	12	0	23	32	32	0	23	0	23
326541	2EKPC OFFICE69.000	P1	9	9	8	9	0	0	9	9
911005	GI2019-004GS0.6450	1	211	264	264	264	264	264	211	264
911008	GI2019-004GB0.6450	2	-6	65	-57	65	-57	65	-6	65
990001	GI2017-002G 34.500	1	69	86	86	86	86	86	69	86
990105	GI2019-003GS0.6450	1	130	163	163	163	163	163	130	163
990108	GI2019-003GB0.6450	2	-6	38	-37	38	-37	38	-6	38
991044	2019-GI002 G0.5500	1	84	125	104	125	105	111	84	111
991160	2019-GI001 G0.6600	1	NA	NA	111	112	111	112	89	112
999003	GI-003 GEN 34.500	1	28	35	35	35	35	35	28	35
999100	2019-GI008 G0.6600	1	81	110	101	110	101	110	81	110
999104	2019-GI015 G0.7000	1	81	104	101	104	101	104	81	104
999119	2019-GI020 G0.7000	1	69	88	86	88	86	88	69	88
999129	GI-2019-029S0.5500	1	101	114	101	114	101	114	101	114
999139	2019-GI023 G0.7000	1	122	153	152	153	152	153	152	153
999144	2019-GI025G 0.6000	1	80	100	100	100	100	100	80	100

Appendix F: Switching Procedures

No switching procedures were relied upon to dismiss potential constraints in this study.