Siting Board Post-Hearing 1-1:

Provide any interconnection reports that involve this project that have yet to be submitted to the Siting Board.

Response:

- A Generator Interconnect Agreement (GIA) among PJM, Barrelhead Solar, LLC, and East Kentucky Power Cooperative, Inc., was filed with FERC on February 11, 2026, which is provided as Attachment PHDR 1-1a.
- Two Affected Systems Studies were completed. Please see the Louisville Gas and Electric Affected Systems Study completed February 20, 2026, provided as Attachment PHDR 1-1b. The MISO Affected System Study was completed September 12, 2025; however, the study was not provided to the Developer until February 6, 2026, as a restudy is in progress, which is attached as Attachment PHDR 1-1c.

Witness: Trudie Grattan

PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403

Christopher Wright
Counsel
(610) 716-9558
Chris.Wright@pjm.com

February 11, 2026

The Honorable Debbie-Anne Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426-0001

Re: PJM Interconnection, L.L.C., Docket No. ER26-1337-000
Original Generation Interconnection Agreement, Service Agreement No. 7834;
Project Identifier No. AG1-471

Dear Secretary Reese:

Pursuant to section 205 of the Federal Power Act,[1] part 35 of the Federal Energy Regulatory Commission's ("Commission") regulations,[2] and PJM's Open Access Transmission Tariff ("Tariff"), Part VII, PJM Interconnection, L.L.C. ("PJM") submits for filing an executed Generation Interconnection Agreement ("GIA") among PJM, Barrelhead Solar, LLC ("Project Developer" or "Barrelhead Solar"), and East Kentucky Power Cooperative, Inc. ("Transmission Owner" or "EKPC") (collectively, the "Interconnection Parties") ("Barrelhead Solar GIA").[3] PJM requests an effective date of January 12, 2026 for the Barrelhead Solar GIA, designated as Original Service Agreement No. 7834.

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. part 35.

[3] Because the Barrelhead Solar GIA filed electronically with this transmittal letter contains electronic signatures and not the original signatures of the Interconnection Parties, a copy of the sheet containing the original signatures is included as Attachment B to this transmittal letter. The Barrelhead Solar GIA also contains Appendices 1 and 2. Appendix 1 contains all the definitions from Tariff, Part VII, Subpart A, section 300. Appendix 2 contains all the standard terms and conditions set forth in PJM's Form of Generation Interconnection Agreement Combined with Construction Service Agreement in Tariff, Part IX, Subpart B ("*pro forma* GIA"). PJM compiled the appendices attached to the Barrelhead Solar GIA from a version of the Tariff in effect as of the requested effective date of the Barrelhead Solar GIA.

On December 17, 2025, PJM contemporaneously issued 134 service agreements for execution, including the Barrelhead Solar GIA, for approximately 87 projects that were studied as part of PJM's Transition Cycle No. 1 ("TC1").[4] Collectively, the service agreements issued for execution by the Project Developers in PJM's TC1 cohort represent approximately 14.4 gigawatts ("GW") of energy, including 6.8 GW of capacity.

PJM submits the Barrelhead Solar GIA for filing because, as described in more detail below and shown in redlines in Attachment C to this transmittal letter, the Barrelhead Solar GIA includes a Schedule of Charges and provisions that do not conform to the *pro forma* GIA set forth in Tariff, Part IX, Subpart B.

I. DESCRIPTION OF THE BARRELHEAD SOLAR GIA

The Barrelhead Solar GIA facilitates the interconnection to the Transmission System[5] of 54 megawatts ("MW") of Maximum Facility Output ("MFO") at the Barrelhead Generating Facility located in Alpha, Wayne County, Kentucky.[6] The Barrelhead Solar GIA specifies that Project Developer shall have 32.4 MW of Capacity Interconnection Rights ("CIRs") at the Point of Interconnection ("POI") identified in the Barrelhead Solar GIA.[7]

As memorialized in the Barrelhead Solar GIA, Barrelhead Solar has posted Security in the amount of $13,905,000.00.[8] Barrelhead Solar's Security includes a Transmission Owner

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[4] PJM Inside Lines, *PJM Completes Interconnection Reform Transition Cycle 1 Studies*, PJM Interconnection, L.L.C. (Sep. 22, 2025), https://insidelines.pjm.com/pjm-completes-interconnection-reform-transition-cycle-1-studies/ (noting "[t]he successful completion of Transition Cycle 1, Phase III was made possible . . . by in-house software that has automated all or parts of the study process, the way study reports are written and drafting of agreements").

[5] Unless otherwise defined in this letter, all capitalized terms herein shall have the meanings set forth in the Tariff.

[6] *See* Barrelhead Solar GIA, Specifications, section 1.0.

[7] *See* Barrelhead Solar GIA, Specifications, section 2.1.

[8] *See* Barrelhead Solar GIA, section 5.0.

Interconnection Facilities ("TOIF") charge of $718,000.00, a Network Upgrades charge of $13,187,000.00, Option to Build charges of $0.00, a Distribution Upgrades charge of $0.00, and other charges of $0.00, for a total of $13,905,000.00, which consists of $7,239,000.00 in direct labor costs, $5,274,000.00 in direct material costs, $1,252,000.00 in indirect labor costs, and $140,000.00 in indirect material costs.[9]

II. DESCRIPTION OF THE SCHEDULE OF CHARGES OF THE BARRELHEAD SOLAR GIA

Schedule E of the Barrelhead Solar GIA contains a Schedule of Charges describing the Monthly Charge that Project Developer will pay to Transmission Owner.[10] The Commission has accepted PJM GIAs containing similar provisions, and PJM asks the Commission to do the same here.[11]

III. DESCRIPTION OF THE NONCONFORMING PROVISIONS OF THE BARRELHEAD SOLAR GIA

The Barrelhead Solar GIA contains nonconforming provisions described herein and shown in Attachment C. The Commission may accept a nonconforming interconnection agreement where such nonconforming agreement is necessary for interconnections with specific reliability concerns, novel legal issues, or other unique factors.[12] As described below, these nonconforming provisions

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[9] *See* Barrelhead Solar GIA, Specifications, sections 4.1–4.6.

[10] *See* Barrelhead Solar GIA, Schedule E. Redlined pages showing the Schedule of Charges are contained in Attachment C to this transmittal letter.

[11] *See PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER25-706-000 (Feb. 11, 2025); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER25-64-000 (Dec. 2, 2024); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER24-2216-000 (Aug. 5, 2024); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER24-2215-000 (Aug. 5, 2024); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER24-1992-000 (July 1, 2024).

[12] *PJM Interconnection, L.L.C.*, 189 FERC ¶ 61,078, at P 26 (2024), *order on reh'g*, 191 FERC ¶ 61,025 (2025); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at PP 913-915 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109

are reasonable, as they address specific reliability concerns, novel legal issues, or other unique factors, as required by the Commission. Moreover, these provisions will not adversely impact the reliability of the Transmission System. The remainder of the Barrelhead Solar GIA is conforming.

A. Affected System Studies and Required Affected System Upgrades – System Reinforcements

Schedule F of the Barrelhead Solar GIA contains nonconforming language that lists Louisville Gas & Electric's ("LG&E") and Midcontinent Independent System Operator's ("MISO") transmission systems as an Affected Systems. Schedule F makes clear that the results of the Affected Systems' studies provided by LG&E and MISO are subject to adjustments based on the outcome of any remaining phases of LG&E's and MISO's interconnection processes.

Schedule F of the Barrelhead Solar GIA specifies that the Barrelhead Solar's project is contingent upon any Affected Systems upgrades identified in Schedule F and in the System Impact Studies Report for AG1-471. Schedule F of the Barrelhead Solar GIA specifies whether the project has a cost allocation for any required Affected Systems upgrades and obligates Barrelhead Solar to enter into any agreements required by LG&E and MISO for Affected Systems upgrades where Barrelhead Solar has a cost allocation. Schedule F further specifies that the Barrelhead Generating Facility may be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of any remaining studies or necessary restudies, or prior to completion of any identified required Affected System upgrades.[13]

These provisions are reasonable and necessary to accommodate the interconnection of the Barrelhead Generating Facility. Additionally, the Commission has accepted GIAs and other

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FERC ¶ 61,287, at P 140 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[13] Tariff, Part VII, Subpart G, section 336(A)(2).

service agreements with similar non-standard terms addressing Affected Systems and cost allocation issues, and should do so here.[14]

B. Nonconforming changes to facilitate PJM's automation technology.

To facilitate the processing of TC1 projects, PJM developed and implemented in-house software that has automated all or parts of the study process, the preparation of study reports, as well as the drafting of service agreements. The use of automation technology, however, necessitated a technically non-conforming but *de minimis* change to the *pro forma* GIA. Specifically, the instructions for Specifications, section 3.0(c) require specification of the name of any additional Transmission Owner constructing facilities with which Project Developer and Transmission Provider will also execute a Construction Service Agreement. The Barrelhead Solar GIA modifies the instructions to state that "[a]ny additional Transmission Owner constructing facilities with which Project Developer and Transmission Provider will also execute a Construction Service Agreement appears below."

IV. EFFECTIVE DATE

Consistent with the Commission's prior notice requirements,[15] PJM requests that the Commission grant an effective date of January 12, 2026 for the Barrelhead Solar GIA. This effective date is appropriate because the Barrelhead Solar GIA is a service agreement for which

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[14] *See PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER25-1268-000 (Apr. 9, 2025); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER23-2799-001 (Jan. 1, 2024); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER23-2663-002 (May 7, 2024); *PJM Interconnection, L.L.C.*, Docket No. ER23-2333-002 (Mar. 26, 2024); *see also PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER23-2812-002 (Mar. 5, 2024); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER22-2945-000 (Nov. 23, 2022).

[15] 18 C.F.R. § 35.3(a)(2).

there is a form of agreement set forth in Tariff, Part IX, Subpart B, and is being filed within thirty (30) days of commencement of service under the agreement.[16]

V. DOCUMENTS ENCLOSED

In addition to this transmittal letter, PJM encloses the following:

1. Attachment A – Original GIA, Service Agreement No. 7834 (Clean Format);
2. Attachment B – Copy of Sheet Containing Original Signatures and Initialed Replacement Pages; and
3. Attachment C – Redlined Pages Showing Schedule of Charges and Nonconforming Provisions.

[16] *See Prior Notice & Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, at 61,983-84 (1993).

VI. CORRESPONDENCE AND COMMUNICATIONS

All notices, correspondence, and communications with respect to this filing should be directed to, and PJM asks the Secretary to include on the official service list, the following:[17]

Christopher Holt
Managing Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403-2497
(267) 885-6749
Christopher.Holt@pjm.com

Christopher Wright
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403-2497
(610) 716-9558
Chris.Wright@pjm.com

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
Craig.Glazer@pjm.com

VII. SERVICE

PJM has served a copy of this filing on Project Developer, Transmission Owner, and the relevant state utility regulatory commissions within the PJM Region.

[17] PJM requests waiver of Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), to permit all of the persons listed to be placed on the official service list for this proceeding.

VIII. CONCLUSION

For the reasons set forth in this transmittal, PJM respectfully requests the Commission to accept the Barrelhead Solar GIA effective as of January 12, 2026.

Respectfully submitted,

By: /s/ *Christopher Wright*

Christopher Holt
Managing Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403-2497
(267) 885-6749
Christopher.Holt@pjm.com

Christopher Wright
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403-2497
(610) 716-9558
Chris.Wright@pjm.com

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
Craig.Glazer@pjm.com

cc (via email):

Project Developer
Austin Brier - pjminterconnection@birchcreekdev.com
legal@birchcreekdev.com

Transmission Owner
Darrin Adams - darrin.adams@ekpc.coop
Chuck Dugan – chuck.dugan@ekpc.coop

All state utility regulatory commissions within the PJM Region

ATTACHMENT A

Original GIA, Service Agreement No. 7834
(Clean Format)

Service Agreement No. 7834

(Project Identifier #AG1-471)

GENERATION INTERCONNECTION AGREEMENT
By and Between
PJM INTERCONNECTION, L.L.C.
And
BARRELHEAD SOLAR, LLC
And
EAST KENTUCKY POWER COOPERATIVE, INC.

Service Agreement No. 7834

GENERATION INTERCONNECTION AGREEMENT
By and Between
PJM Interconnection, L.L.C.
And
Barrelhead Solar, LLC
And
East Kentucky Power Cooperative, Inc.
(Project Identifier #AG1-471)

1.0 Parties. This Generation Interconnection Agreement ("GIA") including the Specifications, Schedules and Appendices attached hereto and incorporated herein, is entered into by and between PJM Interconnection, L.L.C., the Regional Transmission Organization for the PJM Region (hereinafter "Transmission Provider" or "PJM"), Barrelhead Solar, LLC ("Project Developer") and East Kentucky Power Cooperative, Inc. ("Transmission Owner" or "EKPC"). All capitalized terms herein shall have the meanings set forth in the appended definitions of such terms as stated in Part VII and Part VIII of the PJM Open Access Transmission Tariff ("Tariff").

2.0 Authority. This GIA is entered into pursuant to the Generation Interconnection Procedures ("GIP") set forth in Part VII of the Tariff. Project Developer has requested a GIA under the Tariff, and Transmission Provider has determined that Project Developer is eligible under the Tariff to obtain this GIA. The standard terms and conditions for interconnection as set forth in Appendix 2 to this GIA are hereby specifically incorporated as provisions of this GIA. Transmission Provider, Transmission Owner, and Project Developer agree to and assume all of the rights and obligations of the Transmission Provider, Transmission Owner, and Project Developer, respectively, as set forth in GIA, Appendix 2.

3.0 Generating Facility or Merchant Transmission Facility Specifications. Attached are Specifications for the Generating Facility or Merchant Transmission Facility that Project Developer proposes to interconnect with the Transmission System. Project Developer represents and warrants that, upon completion of construction of such facilities, it will own or control the Generating Facility or Merchant Transmission Facility identified in GIA, Specifications, section 1.0 attached hereto and made a part hereof. In the event that Project Developer will not own the Generating Facility or Merchant Transmission Facility, Project Developer represents and warrants that it is authorized by the owner(s) thereof to enter into this GIA and to represent such control.

4.0 Effective Date. Subject to any necessary regulatory acceptance, this GIA shall become effective on the date it is executed by all Interconnection Parties, or, if the agreement is filed with FERC unexecuted, upon the date specified by FERC. This GIA shall terminate on such date as mutually agreed upon by the parties, unless earlier terminated in accordance with the terms set forth in GIA, Appendix 2. The term of the GIA shall be as provided in GIA, Appendix 2, section 1.3. Interconnection Service shall commence as provided in GIA, Appendix 2, section 1.

5.0 Security. In accord with the GIP, Project Developer shall provide the Transmission Provider (for the benefit of the Transmission Owner) with a letter of credit from an agreed provider or other form of security reasonably acceptable to the Transmissions Provider and that names the Transmission Provider as beneficiary ("Security") in the amount of $13,905,000.00. Such Security can also be applied to unpaid Cancellation Costs and for completion of some or all of the required Transmission Owner Interconnection Facilities, and/or Customer-Funded Upgrades. This amount represents the sum of the estimated Costs, determined in accordance with the GIP for which the Project Developer will be responsible, less any Costs already paid by Project Developer. Project Developer acknowledges that its ultimate cost responsibility will be based upon the actual Costs of the facilities described in the Specifications, whether greater or lesser than the amount of the payment security provided under this section.

6.0 Project Specific Milestones. In addition to the milestones stated in the GIP as applicable, during the term of this GIA, Project Developer shall ensure that it meets each of the following development milestones:

6.1 **Acquisition of major electrical equipment.** On or before June 29, 2026, Project Developer, consistent with PJM Manual 14C, must provide PJM with signed memorandums of understanding setting forth the material terms and conditions for the acquisition and delivery of potentially long-lead time major electrical equipment from the intended manufacturers, including but not limited to:

- Control building(s)
- Switchgear
- Disconnect switches
- Photovoltaic racking equipment
- Photovoltaic panels
- Inverters/power conversion systems

6.2 **Affected Systems coordination.** On or before June 29, 2026, Project Developer shall demonstrate it has entered into a study agreement with Louisville Gas & Electric (LG&E) leading to the construction of any required transmission facilities or upgrades on the LG&E transmission system as an Affected System. See Schedule F of this GIA for additional provisions.

6.3 **Purchase of long-lead major electrical equipment.** On or before June 29, 2026, Project Developer must demonstrate its purchase of the following major electrical equipment, consistent with PJM Manual 14C, and the expected delivery dates:

- Main power transformer(s)/generation step up transformer(s)

- Breakers

6.4 **Major Site permits.** On or before July 25, 2027, Project Developer must obtain all major federal, state, and county site permits or comparable certificates necessary to confirm the project site is viable for development, consistent with PJM Manual 14C, including but not limited to the following:

- Zoning and land-use permits
- Wetlands/waterbody impacts
- Environmental impact assessments
- Cultural resource assessments
- Endangered species
- Any additional required federal authorizations

6.5 **Affected Systems coordination.** On or before July 25, 2027, Project Developer shall demonstrate it has entered into an agreement with Midcontinent Independent System Operator (MISO) for the construction of any required transmission facilities or upgrades on the MISO transmission system as an Affected System. See Schedule F of this GIA for additional provisions.

6.6 **Purchase of short-lead major electrical equipment.** On or before July 25, 2027, Project Developer must demonstrate its purchase of the following major electrical equipment, consistent with PJM Manual 14C, and the expected delivery dates:

- Control building(s)
- Switchgear
- Disconnect switches
- Photovoltaic racking equipment
- Photovoltaic panels
- Inverters/power conversion systems

6.7 **Final stage construction permits.** On or before January 15, 2028, Project Developer must obtain all remaining necessary local, county, and state site permits, consistent with PJM Manual 14C, such as but not limited to:

- Stormwater management permits
- All remaining ministerial permits

6.8 **Substantial Site work completed.**

6.8.1 On or before April 15, 2028, Project Developer must demonstrate, via a construction status report submitted to PJM, completion of at least twenty percent (20%) of the major project site construction activities, consistent with PJM Manual 14C, which states that substantial site work is typically considered complete with the end of civil construction activities. For this project, substantial site work shall include, but is not limited to:

- Site clearing and grading in accordance with the construction plan;
- Installation of access roads capable of supporting construction and material deliveries;
- Implementation of stormwater and environmental controls (e.g., retention ponds, berms, or silt fencing) necessary to stabilize the site;
- Commencement of racking system installation, or pile-driving activities sufficient to demonstrate material progress; and
- Completion of civil work required to support installation of major electrical equipment specified in this GIA.

6.8.2 On or before April 15, 2028, Project Developer must submit to Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Project Developer Interconnection Facilities.

6.9 **Delivery of major electrical equipment.** On or before July 15, 2028, Project Developer must demonstrate that the following major electrical equipment, consistent with PJM Manual 14C, has been delivered to Project Developer's project site:

- Main power transformer(s)/generation step up transformer(s)
- Breakers
- Control building(s)
- Switchgear
- Disconnect switches
- Photovoltaic racking equipment
- Photovoltaic panels
- Inverters/power conversion systems

6.10 **Dispatchability Demonstration** During test energization, the Project Developer will demonstrate that the Generating Facility is capable of responding to Transmission Provider instructions with reliable, controllable, and timely changes in output, fulfilling all operational requirements for dispatchable resources as outlined in PJM Manual 14-D, including but not limited to the following:

- Demonstrates continuous real-time communication with PJM.

- Automated dispatch commands can be received and executed without manual intervention.
- Integration with SCADA or EMS systems to receive and act on dispatch signals.
- Completes a series of test dispatch events demonstrating the ability to ramp up/down within specified timeframes (e.g., X MW/min).
- Proves stable minimum and maximum generation output levels without operator overrides.

6.11 **Commercial Operation.** On or before January 15, 2029, Project Developer must demonstrate commercial operation of all generating units in order to achieve the full Maximum Facility Output set forth in section 1.0(c) of the Specifications to this GIA. Failure to achieve this Maximum Facility Output may result in a permanent reduction in Maximum Facility Output of the Generating Facility, and, if necessary, a permanent reduction of the Capacity Interconnection Rights, to the level achieved. Demonstrating commercial operation includes achieving Initial Operation in accordance with section 1.4 of Appendix 2 to this GIA and making commercial sales or use of energy, as well as, if applicable, obtaining capacity qualification in accordance with the requirements of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and fulfillment of 6.10 “Dispatchability Demonstration” milestone.

6.12 **As-Built Data.** As a condition precedent to PJM reflecting an “in-service” status for the Generating Facility or the Merchant Transmission Facilities and no later than 30 days following the demonstration of commercial operation, Project Developer must provide certified documentation demonstrating that “as-built” Generating Facility or the Merchant Transmission Facilities, and Project Developer Interconnection Facilities are in accordance with applicable PJM studies and agreements. Project Developer must also provide PJM with “as-built” electrical modeling data and confirm that previously submitted data remains valid. All modeling data must conform to the PJM Dynamic Model Development Guidelines for Interconnection Analysis in effect as of the effective date of this GIA.

Project Developer shall demonstrate the occurrence of each of the foregoing milestones to Transmission Provider’s reasonable satisfaction. Transmission Provider may reasonably extend any such milestone dates, in the event of delays that Project Developer (i) did not cause and (ii) could not have remedied through the exercise of due diligence. Project Developer shall also have a one-time option to extend its milestone (other than any milestone related to Site Control) for a total period of one year regardless of cause. This option may only be applied one time for an Interconnection Request, and may only be applied to one single milestone specified in this GIA. Other milestone dates stated in this GIA shall be deemed to be extended coextensively with Project Developer’s use of this provision. Once this extension is used, it is no longer available with regard to any other milestones or other deadlines in this GIA. If the Project Developer fails to meet any of the milestones set forth above, including any extended milestones, its Interconnection

Request shall be terminated and withdrawn, subject to the provisions of Appendix 2, sections 15 and 16. Transmission Provider shall take all necessary steps to effectuate this termination, including submitting the necessary filings with FERC.

7.0 Provision of Interconnection Service. Transmission Provider and Transmission Owner agree to provide for the interconnection to the Transmission System in the PJM Region of Project Developer's Generating Facility or Merchant Transmission Facility identified in the Specifications in accordance with the GIP, the Operating Agreement, and this GIA, as they may be amended from time to time.

8.0 Assumption of Tariff Obligations. Project Developer agrees to abide by all rules and procedures pertaining to generation and transmission in the PJM Region, including but not limited to the rules and procedures concerning the dispatch of generation or scheduling transmission set forth in the Tariff, the Operating Agreement and the PJM Manuals.

9.0 System Impact Study(ies) and/or Facilities Study(ies). In analyzing and preparing the System Impact Study(ies) and/or Facilities Study(ies), and in designing and constructing the Distribution Upgrades, Network Upgrades, Stand Alone Network Upgrades and/or Transmission Owner Interconnection Facilities described in the Specifications attached to this GIA, Transmission Provider, the Transmission Owner(s), and any other subcontractors employed by Transmission Provider have had to, and shall have to, rely on information provided by Project Developer and possibly by third parties and may not have control over the accuracy of such information. Accordingly, NEITHER TRANSMISSION PROVIDER, THE TRANSMISSION OWNER(s), NOR ANY OTHER SUBCONTRACTORS EMPLOYED BY TRANSMISSION PROVIDER OR TRANSMISSION OWNER MAKES ANY WARRANTIES, EXPRESS OR IMPLIED, WHETHER ARISING BY OPERATION OF LAW, COURSE OF PERFORMANCE OR DEALING, CUSTOM, USAGE IN THE TRADE OR PROFESSION, OR OTHERWISE, INCLUDING WITHOUT LIMITATION IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, WITH REGARD TO THE ACCURACY, CONTENT, OR CONCLUSIONS OF THE SYSTEM IMPACT STUDY(IES) AND/OR FACILITIES STUDY(IES) OF THE DISTRIBUTION UPGRADES, NETWORK UPGRADES, STAND ALONE NETWORK UPGRADES AND/OR TRANSMISSION OWNER INTERCONNECTION FACILITIES. Project Developer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

10.0 Construction of Transmission Owner Interconnection Facilities and Transmission Owner Upgrades

10.1. Cost Responsibility. Project Developer shall be responsible for and shall pay upon demand all Costs associated with the interconnection of the Generating Facility or Merchant Transmission Facility as specified in the GIP. These Costs may include, but are not limited to, a Distribution Upgrades charge, Network Upgrades charge, Stand Alone Network Upgrades charge, Transmission Owner Interconnection

Facilities charge and other charges. A description of the facilities required and an estimate of the Costs of these facilities are included in sections 3.0 and 4.0 of the Specifications to this GIA.

10.2. Billing and Payments. Transmission Provider shall bill the Project Developer for the Costs associated with the facilities contemplated by this GIA, estimates of which are set forth in the Specifications to this GIA, and the Project Developer shall pay such Costs, in accordance with section 11 of Appendix 2 to this GIA and the applicable provisions of Schedule L. Upon receipt of each of Project Developer's payments of such bills, Transmission Provider shall reimburse the applicable Transmission Owner. Project Developer requests that Transmission Provider provide a quarterly cost reconciliation:

___X____ Yes

___ __ No

10.3. Contract Option. In the event that the Project Developer and Transmission Owner agree to utilize the Negotiated Contract Option as set forth in Schedule L, Appendix 1 to establish, subject to FERC acceptance, non-standard terms regarding cost responsibility, payment, billing and/or financing, the terms of sections 10.1 and/or 10.2 of this section 10.0 shall be superseded to the extent required to conform to such negotiated terms, as stated in Schedule L to this GIA. The Negotiated Option can only be used in connection with a Network Upgrade subject to the Network Upgrade Cost Responsibility Agreement if all Project Developers and the relevant Transmission Owner agree.

_______ Yes

___X___ No

10.4 Interconnection Construction Terms and Conditions

10.4.1 GIA, Schedule L sets forth the additional terms and conditions of service that apply in the event there are any Project Developer Interconnection Facilities, Transmission Owner Interconnection Facilities, or Transmission Owner Upgrades subject to this Agreement. In the event there is an additional Transmission Owner listed in GIA, Specifications, section 3.0(c), Transmission Provider, Project Developer and the additional Transmission Owner shall be required to enter into a separate Construction Service Agreement in the form set forth in Tariff, Part IX, Subpart J. In the event there are any Common Use Upgrades listed in GIA, Specifications, section 3.0, Transmission Provider and Project Developer, along with the other relevant Project Developers, shall also be required to enter into a separate Network Upgrade Cost Responsibility Agreement in the form set forth in Tariff, Part IX, Subpart H.

10.4.2 In the event that the Project Developer elects to construct some or all of the Transmission Owner Interconnection Facilities or Stand Alone Network Upgrades under the Option to Build, billing and payment for the Costs associated with the facilities contemplated by this GIA shall relate only to such portion of the Interconnection Facilities and Transmission Owner Upgrades as the Transmission Owner is responsible for building.

11.0 Interconnection Specifications

11.1 Point of Interconnection. The Point of Interconnection shall be as identified on the single-line diagram attached as GIA, Schedule B.

11.2 List and Ownership of Interconnection Facilities and Transmission Owner Upgrades. The Interconnection Facilities and Transmission Owner Upgrades to be constructed and ownership of the components thereof are identified in GIA, section 3.0.

11.3 Ownership and Location of Metering Equipment. The Metering Equipment to be constructed, the capability of the Metering Equipment to be constructed, and the ownership thereof, are identified on the attached GIA, Schedule C.

11.4 Applicable Technical Standards. The Applicable Technical Requirements and Standards that apply to the Generating Facility or Merchant Transmission Facility and the Interconnection Facilities and Transmission Owner Upgrades are identified in GIA, Schedule D.

12.0 Power Factor Requirement.

Consistent with section 4.6 of Appendix 2 to this GIA, the power factor requirement is as follows:

The Generation Project Developer shall design its non-synchronous Generating Facility with the ability to maintain a power factor of at least 0.95 leading to 0.95 lagging measured at the high-side of the facility substation transformers.

13.0 Charges. In accordance with sections 10 and 11 of Appendix 2 to this GIA, the Project Developer shall pay to the Transmission Provider the charges applicable after Initial Operation, as set forth in Schedule E to this GIA. Promptly after receipt of such payments, the Transmission Provider shall forward such payments to the appropriate Transmission Owner.

14.0 Third Party Beneficiaries. No third party beneficiary rights are created under this GIA, except, however, that, subject to modification of the payment terms stated in section 10 of this GIA pursuant to the Negotiated Contract Option, payment obligations imposed on Project Developer under this GIA are agreed and acknowledged to be for the benefit of the

Transmission Owner(s). Project Developer expressly agrees that the Transmission Owner(s) shall be entitled to take such legal recourse as it deems appropriate against Project Developer for the payment of any Costs or charges authorized under this GIA or the GIP with respect to Interconnection Service for which Project Developer fails, in whole or in part, to pay as provided in this GIA, the GIP and/or the Operating Agreement.

15.0 Waiver. No waiver by either party of one or more defaults by the other in performance of any of the provisions of this GIA shall operate or be construed as a waiver of any other or further default or defaults, whether of a like or different character.

16.0 Amendment. Except as set forth in GIA, Appendix 2, this GIA or any part thereof, may not be amended, modified, or waived other than by a written document signed by all parties hereto. Parties acknowledge that, subsequent to execution of this agreement, errors may be corrected by replacing the page of the agreement containing the error with a corrected page, as agreed to and signed by the parties without modifying or altering the original date of execution, dates of any milestones, or obligations contained therein.

17.0 Construction With Other Parts of The Tariff. This GIA shall not be construed as an application for service under Part II or Part III of the Tariff.

18.0 Notices. Any notice or request made by either party regarding this GIA shall be made, in accordance with the terms of Appendix 2 to this GIA, to the representatives of the other party and as applicable, to the Transmission Owner(s), as indicated below:

Transmission Provider:

PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
interconnectionagreementnotices@pjm.com

Project Developer:

Barrelhead Solar, LLC
2650 Locust Street, Suite 100
St. Louis, Missouri 63103
Attn: Austin Brier, Director of Interconnection, or successor
Email: pjminterconnection@birchcreekdev.com

With Copies to:
Email: legal@birchcreekdev.com

Transmission Owner:

East Kentucky Power Cooperative, Inc.
4775 Lexington Road

P.O. Box 707
Winchester, KY 40392-0707
Attn: Darrin Adams, Director – Transmission Planning & Protection, or successor
darrin.adams@ekpc.coop
859-745-9664

19.0 Incorporation of Other Documents. All portions of the Tariff and the Operating Agreement pertinent to the subject matter of this GIA and not otherwise made a part hereof are hereby incorporated herein and made a part hereof.

20.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service. Subject to FERC approval, the parties agree that the terms and conditions set forth in Schedule F hereto are hereby incorporated herein by reference and be made a part of this GIA. In the event of any conflict between a provision of Schedule F that FERC has accepted and any provision of Appendix 2 to this GIA that relates to the same subject matter, the pertinent provision of Schedule F shall control.

21.0 Addendum of Project Developer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status. To the extent required, in accordance with section 24.1 of Appendix 2 to this GIA, Schedule G to this GIA shall set forth the Project Developer's agreement to conform with the IRS safe harbor provisions for non-taxable status.

22.0 Addendum of Interconnection Requirements for all Wind or Non-synchronous Generation Facilities. To the extent required, Schedule H to this GIA sets forth interconnection requirements for wind or non-synchronous generation facilities and is hereby incorporated by reference and made a part of this GIA.

23.0 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Interconnection Parties agree to comply with all infrastructure security requirements of the North American Electric Reliability Corporation. All Transmission Providers, Transmission Owners, Market Participants, and Project Developers interconnected with electric systems are to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

24.0 This Agreement shall be deemed a contract made under, and the interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with, the applicable Federal and/or laws of the State of Delaware without regard to conflicts of laws provisions that would apply the laws of another jurisdiction.

IN WITNESS WHEREOF, Transmission Provider, Project Developer and Transmission Owner have caused this GIA to be executed by their respective authorized officials.

(Project Identifier #AG1-471)

Transmission Provider: **PJM Interconnection, L.L.C.**

By: /s/ *Andrew Lambert*	Manager, Interconnection Planning Projects	Jan 12, 2026
Name	Title	Date

Printed name of signer: Andrew Lambert

Project Developer: **Barrelhead Solar, LLC**

By: /s/ *Chris Norqual*	Authorized Representative	Jan 7, 2026
Name	Title	Date

Printed name of signer: Chris Norqual

Transmission Owner: **East Kentucky Power Cooperative, Inc.**

By: /s/ *Brad Young*	Vice President	Jan 8, 2026
Name	Title	Date

Printed name of signer: Brad Young

**SPECIFICATIONS FOR
GENERATION INTERCONNECTION AGREEMENT
By and Among
PJM INTERCONNECTION, L.L.C.
And
BARRELHEAD SOLAR, LLC
And
EAST KENTUCKY POWER COOPERATIVE, INC.
(Project Identifier #AG1-471)**

1.0 Description of Generating Facility to be interconnected with the Transmission System in the PJM Region:

a. Name of Generating Facility or Merchant Transmission Facility:

Barrelhead

b. Location of Generating Facility or Merchant Transmission Facility:

36.774310, -85.007715
Alpha, Wayne County, Kentucky

c. Size in megawatts of Generating Facility or Merchant Transmission Facility:

For Generation Project Developer:

Maximum Facility Output of 54 MW

d. Description of the equipment configuration:

A solar generating facility consisting of eighteen (18) x 3.069444 MW Sungrow SG3600UD inverters and eighteen (18) x 3.6 MVA 34.5/0.63 kV inverter step-up transformers and solar panels with a /tracker system supporting 54.0 MWE. The facility will also include circuit breakers and/or switches required for the generating facility, protection and control relays and any associated enclosure and one (1) x 63.3/50.7/38.0 MVA 69.0/34.5 kV main power transformer with a high-side voltage of 69 kV.

2.0 Rights

2.1 Capacity Interconnection Rights:

Pursuant to and subject to the applicable terms of the GIP, the Project Developer shall have Capacity Interconnection Rights at the Point(s) of Interconnection specified in this Generation Interconnection Agreement in the amount of 32.4 MW.

Project Identifier	Fuel	Capacity Interconnection Rights (MW)
AG1-471	Solar	32.4
Grand Total		32.4

2.1a To the extent that any portion of the Generating Facility described in Specifications, section 1.0 is not a Capacity Resource with Capacity Interconnection Rights, such portion of the Generating Facility shall be an Energy Resource. PJM reserves the right to limit total injections to the Maximum Facility Output in the event reliability would be affected by output greater than such quantity.

3.0 Construction Responsibility and Ownership of Interconnection Facilities and Transmission Owner Upgrades/Scope of Work.

a. Project Developer.

(1) Project Developer shall construct and, unless otherwise indicated, shall own, the following Interconnection Facilities:

i. Facilities for which the Project Developer has sole cost responsibility.

a. One (1) 69 kV circuit breaker;
b. One (1) 69 kV generator lead line from the high side of the Project Developer's collector substation to the Point of Change in Ownership.

ii. Facilities for which a Network Upgrade Cost Responsibility Agreement is required.

None

(2) In the event that Project Developer has exercised the Option to Build, it is hereby permitted to build in accordance with and subject to the conditions and limitations set forth in GIA, Schedule L, the following portions of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades which constitute or are part of the Generating Facility or Merchant Transmission Facility:

None

Ownership of the facilities built by Project Developer pursuant to the Option to Build shall be as provided in Schedule L.

b. Transmission Owner

i. Facilities for which the Project Developer has sole cost responsibility.

Identifier	Description	Category
	One (1) 69 kV generator lead line to include, but not be limited to, installation of a 69 kV line monopole dead-end structure and foundation, a 3-pole disconnect switch mounted to the monopole, line conductor from the dead-end structure to the bus position in the switchyard, and two (2) 48-strand fiber optic cables.	Transmission Owner Interconnection Facilities
n9510.0	Install new overhead optical ground wire (OPGW) on the existing Wayne County - Massingale Road and Massingale Road - Summer Shade 69 kV line sections for a total of 44.2 miles.	Network Upgrades
n9511.0	Loop existing Upchurch Tap - Wayne County 69 kV line into new interconnection switching station.	Network Upgrades
n9512.0	Revise Relay Settings at Wayne County Sub.	Network Upgrades
n9513.0	Revise Relay Settings at Summer Shade Sub.	Network Upgrades
n9514.0	Massingale Road Substation: Construct new 69 kV switching station.	Stand-Alone Network Upgrades

ii. Facilities for which a Network Upgrade Cost Responsibility Agreement is required.

Identifier	Description	Category
(None)		

c. Any additional Transmission Owner constructing facilities with which Project Developer and Transmission Provider will also execute a Construction Service Agreement appears below

i. Facilities for which the Project Developer has sole cost responsibility.

Identifier	Description	Category	Transmission Owner
(None)			

ii. Facilities for which a Network Upgrade Cost Responsibility Agreement is required.

Identifier	Description	Category	Transmission Owner
(None)			

d. Additional Contingent Facilities which must be completed prior to Commercial Operation of the Generating Facility or Merchant Transmission Facility

Except as determined through an interim deliverability study for a particular Delivery Year, in order to maintain system reliability, the 54 MW Energy / 32.4 MW Capacity associated with PJM Project Identifier AG1-471 and the Generating Facility under this GIA cannot come fully into service prior to the completion of the following PJM Network Upgrade(s), baseline upgrade(s), and/or Supplemental Project upgrades:

Identifier	Description	Category
(None)		

4.0 Subject to modification pursuant to the Negotiated Contract Option and/or the Option to Build, Project Developer shall be subject to the estimated charges detailed below, which shall be billed and paid in accordance with GIA, Appendix 2, section 11 and GIA, Schedule L, section 9.0.

4.1 Transmission Owner Interconnection Facilities Charge: $718,000.00

4.2 Network Upgrades Charge: $13,187,000.00

Identifier	Cost Allocation	Transmission Owner
n9514.0	$7,050,000.00	East Kentucky Power Cooperative, Inc.
n9513.0	$63,000.00	East Kentucky Power Cooperative, Inc.
n9512.0	$63,000.00	East Kentucky Power Cooperative, Inc.
n9511.0	$554,000.00	East Kentucky Power Cooperative, Inc.
n9510.0	$5,457,000.00	East Kentucky Power Cooperative, Inc.

4.3 Option to Build Charges $0.00

4.4 Distribution Upgrades Charge: $0.00

4.5 Other Charges: $0.00

4.6 Cost breakdown:

$	7,239,000.00	Direct Labor
$	5,274,000.00	Direct Material
$	1,252,000.00	Indirect Labor
$	140,000.00	Indirect Material

$13,905,000.00 Total

4.7 Security Amount Breakdown:

$13,905,000.00 Estimated Cost of Network Upgrades, Distribution Upgrades, Transmission Owner Interconnection Facilities, and Other Charges

plus $0.00 Option to Build Security for Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades (including Cancellation Costs)

$13,905,000.00 Sum of Security required for Costs listed in GIA, Specifications sections 4.1 through 4.5

less $0 Portion of Costs already paid by Project Developer

$13,905,000.00 Net Security amount required

APPENDICES:

- **APPENDIX 1 - DEFINITIONS**
- **APPENDIX 2 - STANDARD TERMS AND CONDITIONS FOR INTERCONNECTIONS**

SCHEDULES:

- **SCHEDULE A - GENERATING FACILITY LOCATION/SITE PLAN**
- **SCHEDULE B - SINGLE-LINE DIAGRAM**
- **SCHEDULE C - LIST OF METERING EQUIPMENT**
- **SCHEDULE D - APPLICABLE TECHNICAL REQUIREMENTS AND STANDARDS**
- **SCHEDULE E - SCHEDULE OF CHARGES**
- **SCHEDULE F - SCHEDULE OF NON-STANDARD TERMS & CONDITIONS**
- **SCHEDULE G - PROJECT DEVELOPER'S AGREEMENT TO CONFORM WITH IRS SAFE HARBOR PROVISIONS FOR NON-TAXABLE STATUS**
- **SCHEDULE H - INTERCONNECTION REQUIREMENTS FOR ALL WIND, SOLAR AND NON-SYNCHRONOUS GENERATION FACILITIES**
- **SCHEDULE I – INTERCONNECTION SPECIFICATIONS FOR AN ENERGY STORAGE RESOURCE**
- **SCHEDULE J – SCHEDULE OF TERMS AND CONDITIONS FOR SURPLUS INTERCONNECTION SERVICE**
- **SCHEDULE K – REQUIREMENTS FOR INTERCONNECTION SERVICE BELOW FULL ELECTRICAL GENERATING CAPABILITY**
- **SCHEDULE L – INTERCONNECTION CONSTRUCTION TERMS AND CONDITIONS**
- **SCHEDULE L, APPENDIX 1 – NEGOTIATED CONTRACT OPTION TERMS**

APPENDIX 1

DEFINITIONS

From the Generation Interconnection Procedures accepted for filing by FERC as of the effective date of this agreement

For purposes of these Generation Interconnection Procedures and any agreement set forth in Tariff, Part IX, in the event of a conflict between the definitions set forth herein and the definitions set forth in Tariff, Part I, the definitions set forth in these Generation Interconnection Procedures shall control.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Customer

"Affected System Customer" shall mean the developer responsible for an Affected System Facility that requires Network Upgrades to Transmission Provider's Transmission System.

Affected System Facility

"Affected System Facility" shall mean a new, expanded or upgraded generation or transmission facility outside of Transmission Provider's Transmission System, the effect of which requires Network Upgrades to Transmission Provider's Transmission System.

Affected System Operator

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affected System Customer Facilities Study Application and Agreement

"Affected System Customer Facilities Study Application and Agreement" shall mean the agreement set forth in Tariff, Part IX, Subpart L, Affected System Customer Facilities Study Application and Agreement.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, 10 percent or more of the voting securities of such entity.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, Project Developer, Eligible Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, the Control Area in which the Generating Facility or Merchant Transmission Facility is electrically located and the Transmission Owner FERC Form No. 715 – Annual Transmission Planning and Evaluation Report for each Applicable Regional Entity; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of a Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual. All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Application and Studies Agreement:

"Application and Studies Agreement" shall mean the application that must be submitted by a Project Developer or Eligible Customer that seeks to initiate a New Service Request, a form of which is set forth in Tariff, Part IX, Subpart A. An Application and Studies Agreement must be submitted electronically through PJM's web site in accordance with PJM's Manuals.

Application Deadline:

"Application Deadline" shall mean the Cycle deadline for submitting a Completed New Service Request, as set forth in Tariff, Part VII, Subpart C, sections 306(A) and 306(E). If Project Developer's or Eligible Customer's Completed New Service Request is received by Transmission Provider after a particular Cycle deadline, such Completed New Service Request shall automatically be considered as part of the immediate subsequent Cycle.

Application Phase:

"Application Phase" shall mean the Cycle period encompassing both the submission and review of New Service Requests as set forth in Tariff, Part VII, Subpart C, section 306.

Application Review Phase:

"Application Review Phase" shall mean the review and procedures set forth in Tariff, Part VII, Subpart C, section 306(B).

Base Project:

"Base Project" shall mean: (1) a Generating Facility, Customer Facility, or Participant Facility with an executed and effective Generation Interconnection Agreement, Interconnection Service Agreement, or Wholesale Market Participation Agreement that has demonstrated commercial operation; (2) a commercially operational generation resource with a form of Commission-jurisdictional interconnection-related service agreement; or (3) a project with a valid Generation Interconnection Request that has been submitted and is subject to an interconnection study in a Cycle prior to Transition Cycle #2.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of the Tariff, Part VII, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of the Tariff, Part VII and/or an agreement entered into thereunder.

Business Day:

"Business Day" shall mean a day ending at 5 pm Eastern prevailing time in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Transmission Owner Interconnection Facilities, and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Transmission Owner Interconnection Facilities, and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under the Tariff, Part VII. Cancellation costs may include costs for Customer-Funded Upgrades assigned to Project Developer or Eligible Customer, in accordance with the Tariff and as set forth in GIA, Appendix 2, section 16.1.4, that remain the responsibility of Project Developer or Eligible Customer under the Tariff, even if such New Service Request is terminated or withdrawn.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection.

Capacity Resource:

"Capacity Resource" shall have the meaning provided in the Reliability Assurance Agreement.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with a Generation Interconnection Agreement.

Common Use Upgrade:

"Common Use Upgrade" or "CUU" shall mean a Network Upgrade that is needed for the interconnection of Generating Facilities or Merchant Transmission Facilities of more than one Project Developer or Eligible Customer and which is the shared responsibility of each Project Developer or Eligible Customer.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Completed New Service Request:

"Completed New Service Request" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit(s). A Completed New Service Request, if accepted upon review, shall become a valid New Service Request.

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a Project Developer, Eligible Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any Project Developer, Eligible Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Generation Interconnection Agreement or a Construction Service Agreement.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners

Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner, Project Developer, Eligible Customer or Affected System Customer, depending on which entity has the construction responsibility pursuant to the Tariff, Part VII and the applicable GIA or Construction Service Agreement; this term shall also be used to refer to a Project Developer or Eligible Customer with respect to the construction of the Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement, Network Upgrade Cost Responsibility Agreement or a party to a GIA that requires activities pursuant to a GIA.

Construction Service Agreement:

"Construction Service Agreement" shall mean the agreement entered into by a Developer Party, Transmission Owner and the Transmission Provider pursuant to Tariff, Part VII or Tariff, Part VIII in the form set forth in Tariff, Part IX, Subpart J.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to the Tariff, Part VII.

Cost Responsibility Agreement:

"Cost Responsibility Agreement" shall mean a form of agreement between Transmission Provider and a Project Developer with an existing generating facility, intended to provide the terms and conditions for the Transmission Provider to perform certain modeling, studies or analysis to determine whether the Project Developer may enter into a GIA with PJM and the Transmission Owner. A form of the Cost Responsibility Agreement is set forth in Tariff, Part IX, Subpart F.

Costs:

As used in the Tariff, Part VII and related agreements and attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Distribution Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on a Project Developer or Eligible Customer pursuant to Tariff, Part VII, Subpart D, section 307(A)(5), or (ii) is voluntarily undertaken by an Upgrade Customer in fulfillment of an Upgrade Request. No Network Upgrade, Distribution Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Cycle:

"Cycle" shall mean that period of time between the start of an Application Phase and conclusion of the corresponding Final Agreement Negotiation Phase. The Cycle consists of the Application Phase, Phase I, Decision Point I, Phase II, Decision Point II, Phase III, Decision Point III, and the Final Agreement Negotiation Phase.

Decision Point I:

"Decision Point I" shall mean the time period that commences on the first Business Day immediately following Phase I of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.

Decision Point II:

"Decision Point II" shall mean the time period that commences on the first Business Day immediately following Phase II of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.

Decision Point III:

"Decision Point III" shall mean the time period that commences on the first Business Day immediately following Phase III of a Cycle, and shall end within 30 calendar days; however, if the 30th does not fall on a Business Day, this time period shall conclude on the next Business Day.

Default:

As used in the Generation Interconnection Agreement, Construction Service Agreement, and Network Upgrade Cost Responsibility Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of a Generation Interconnection Agreement, Construction Service Agreement, or Network Upgrade Cost Responsibility Agreement.

Distribution System:

"Distribution System" shall mean the Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades:

"Distribution Upgrades" shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the delivery service necessary to affect Project Developer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Eligible Customer:

"Eligible Customer" shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by the Federal Power Act, section 212(h), such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VII, Eligible Customer shall mean only those Eligible Customers that have submitted an Application and Study Agreement.

Emergency Condition:

"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Project Developer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Generating Facility or to the Project Developer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Project Developer is not obligated by a Generation Interconnection Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Engineering and Procurement Agreement:

"Engineering and Procurement Agreement" shall mean an agreement that authorizes Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request. An Engineering and Procurement Agreement is not intended to be used for the actual construction of any Interconnection Facilities or Transmission Upgrades. A form of the Engineering and Procurement Agreement is set forth in Tariff, Part IX, Subpart D. An Engineering and Procurement Agreement can only be requested by a Project Developer, and can only be requested in Phase III.

Facilities Study:

"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Studies; and (2) complete any additional studies or analyses documented in the System Impact Studies or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of such additional studies.

Federal Power Act:

"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Agreement Negotiation Phase:

"Final Agreement Negotiation Phase" shall mean the phase set forth in Tariff, Part VII, Subpart D, section 314 to tender, negotiate, and execute any service agreement in Tariff, Part IX.

Generating Facility:

"Generating Facility" shall mean Project Developer's device for the production and/or storage for later injection of electricity identified in the New Service Request, but shall not include the Project Developer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

Generation Interconnection Agreement ("GIA"):

"Generation Interconnection Agreement" ("GIA") shall mean the form of interconnection agreement applicable to a Generation Interconnection Request or Transmission Interconnection Request. A form of the GIA is set forth in Tariff, Part IX, Subpart B.

Generation Interconnection Procedures ("GIP"):

"Generation Interconnection Procedures" ("GIP") shall mean the interconnection procedures set forth in Tariff, Part VII.

Generation Interconnection Request:

"Generation Interconnection Request" shall mean a request by a Generation Project Developer pursuant to Tariff, Part VII, Subpart C, section 306, to interconnect a generating unit with the Transmission System or to increase the capacity of a generating unit interconnected with the Transmission System in the PJM Region.

Generation Project Developer:

"Generation Project Developer" shall mean an entity that submits a Generation Interconnection Request to interconnect a new generation facility or to increase the capacity of an existing generation facility interconnected with the Transmission System in the PJM Region.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act, section 215(a)(4).

Governmental Authority:

"Governmental Authority" shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority having jurisdiction over any Interconnection Party or Construction Party or regarding any matter relating to a Generation Interconnection Agreement or Construction Service Agreement, as applicable.

Hazardous Substances:

"Hazardous Substance" shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Incidental Expenses:

"Incidental Expenses" shall mean those expenses incidental to the performance of construction pursuant to a Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Generating Facility and for the Interconnection Facilities.

Incremental Auction Revenue Rights:

"Incremental Auction Revenue Rights" shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Capacity Transfer Rights:

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Project Developer or Transmission Project Developer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

"Incremental Deliverability Rights" ("IDR") shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Project Developer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Initial Operation:

"Initial Operation" shall mean the commencement of operation of the Generating Facility and Project Developer Interconnection Facilities after satisfaction of the conditions of Tariff, Part IX, Subpart B, Appendix 2, section 1.4.

Interconnected Entity:

"Interconnected Entity" shall mean either the Project Developer or the Transmission Owner; Interconnected Entities shall mean both of them.

Interconnection Construction Service Agreement:

"Interconnection Construction Service Agreement" shall mean the agreement entered into by an Project Developer, Transmission Owner and the Transmission Provider pursuant to this Tariff, Part VII in the form set forth in Tariff, Part IX, Subpart J or Tariff, Part IX, Subpart H, relating to construction of Common Use Upgrades, Distribution Upgrades, Network Upgrades, Stand Alone Network Upgrades and/or Transmission Owner Interconnection Facilities and coordination of the construction and interconnection of an associated Generating Facility.

Interconnection Facilities:

"Interconnection Facilities" shall mean the Transmission Owner's Interconnection Facilities and the Project Developer's Interconnection Facilities. Collectively Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modifications, additions, or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades, or Network Upgrades.

Interconnection Party:

"Interconnection Party" shall mean a Transmission Provider, Project Developer, or the Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

"Interconnection Request" shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

"Interconnection Service" shall mean the physical and electrical interconnection of the Generating Facility with the Transmission System pursuant to the terms of this Tariff, Part VII and the Generation Interconnection Agreement entered into pursuant thereto by Project Developer, the Transmission Owner and Transmission Provider.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Material Modification:

"Material Modification" shall mean, as determined through a Necessary Study, any modification to a Generation Interconnection Agreement that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Distribution Upgrades, Network Upgrades, Stand Alone Network Upgrades or Transmission Owner Interconnection Facilities needed to accommodate, any Interconnection Request with a later Cycle.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Generation Interconnection Agreement, after supply of any parasitic or host facility loads, that a Generation Project Developer's Generating Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Generating Facility that Transmission Provider utilized in the System Impact Study.

Maximum State of Charge:

"Maximum State of Charge" shall mean the maximum State of Charge that should not be exceeded, measured in units of megawatt-hours.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to the Tariff.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, or advancement of additions to, or modifications or replacement of, physical facilities of the Transmission Owner that, on the date of the pertinent Upgrade Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan, but that are not already subject to an already existing, fully executed interconnection related agreement, such as a Generation Interconnection Agreement, stand-alone Construction Service Agreement, Network Upgrade Cost Responsibility Agreement or Upgrade Construction Service Agreement.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to the Tariff, Part VII and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Project Developer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Tariff, Attachment T, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Project Developer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to this Tariff, Part VII, Subpart E, section 330, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, Part VII, Subpart E, section 319.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to a Generation Interconnection Agreement.

Minimum State of Charge:

"Minimum State of Charge" shall mean the minimum State of Charge that should be maintained in units of megawatt-hours.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

Necessary Studies Agreement:

"Necessary Studies Agreement" shall mean the form of agreement for preparation of one or more Necessary Studies, as set forth in Tariff, Part IX, Subpart G.

Necessary Study:

"Necessary Study(ies)" shall mean the assessment(s) undertaken by the Transmission Provider to determine whether a planned modification under GIA, Appendix 2, section 3.1 will have a permanent material impact on the Transmission System and to identify the additions, modifications, or replacements to the Transmission System, if any, that are necessary, in accordance with Good Utility Practice, and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards, to accommodate the planned modifications. A form of the Necessary Studies Agreement is set forth in Tariff, Part IX, Subpart G.

Network Upgrade Cost Responsibility Agreement:

"Network Upgrade Cost Responsibility Agreement" shall mean the agreement entered into by the Project Developer and the Transmission Provider pursuant to this GIP, and in the form set forth in Tariff, Part IX, Subpart H, relating to construction of Common Use Upgrades and coordination of the construction and interconnection of associated Generating Facilities. In regard to Common Use Upgrades, a separate Network Upgrade Cost Responsibility Agreement will be executed for each set of Common Use Upgrades on the system of a specific Transmission Owner that is associated with the interconnection of a Generating Facility.

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include Stand Alone Network Upgrades which are Network Upgrades that are not part of an Affected System; only serve the Generating Facility or Merchant Transmission Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Project Developer must agree as to what constitutes Stand Alone Network Upgrades and identify them in the GIA, Specifications, section 3.0 or in the Construction Service Agreement, Schedule C. If the Transmission Provider and Project Developer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Project Developer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

New Service Request:

"New Service Request" shall mean an Interconnection Request or a Completed Application.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Project Developer's Generating Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Project Developer's Generating Facility, as determined in accordance with pertinent Applicable Standards and specified in the Generation Interconnection Agreement.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Option to Build:

"Option to Build" shall mean the option of the Project Developer to build certain Stand Alone Network Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VII:

"Part VII" shall mean Tariff, Part VII, sections 300 through 337 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VIII:

"Part VIII" shall mean Tariff, Part VIII, sections 400 through 435 pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IX:

"Part IX" shall mean Tariff, Part IX, section 500 and Subparts A through L pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Permissible Technological Advancement:

"Permissible Technological Advancement" shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the end of Decision Point II. Provided such change may not: (i) increase the capability of the Generating Facility or Merchant Transmission Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

Phase I

“Phase I” shall start on the first Business Day immediately after the close of the Application Phase of a Cycle, but no earlier than 30 calendar days following the distribution of the Phase I System Impact Study Base Case Data. During Phase I, Transmission Provider shall conduct the Phase I System Impact Study.

Phase I System Impact Study:

“Phase I System Impact Study” shall mean System Impact Study conducted during the Phase I System Impact Study Phase.

Phase II

“Phase II” shall start on the first Business Day immediately after the close of Decision Point I Phase unless the Decision Point III of the immediately preceding Cycle is still open. In no event, shall Phase II of a Cycle commence before the conclusion of Decision Point III of the immediately preceding Cycle. During Phase II, Transmission Provider shall conduct the Phase II System Impact Study.

Phase II System Impact Study:

“Phase II System Impact Study” shall mean System Impact Study conducted during the Phase II System Impact Study Phase.

Phase III

“Phase III” shall start on the first Business Day immediately after the close of Decision Point II, unless the Final Agreement Negotiation Phase of the immediately preceding Cycle is still open. In no event shall Phase III of a Cycle commence before the conclusion of the Final Agreement Negotiation Phase of the immediately preceding Cycle. During Phase III, Transmission Provider shall conduct the Phase III System Impact Study.

Phase III System Impact Study:

“Phase III System Impact Study” shall mean System Impact Study conducted during Phase III.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Point of Change in Ownership:

"Point of Change in Ownership" shall mean the point, as set forth Schedule B of the Generation Interconnection Agreement, where the Project Developer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

Point of Interconnection:

"Point of Interconnection" shall mean the point or points where the Interconnection Facilities connect with the Transmission System.

Project Developer:

"Project Developer" shall mean a Generation Project Developer and/or a Transmission Project Developer.

Project Developer Interconnection Facilities:

"Project Developer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Project Developer on Project Developer's side of the Point of Change in Ownership identified in GIA, Schedule B, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Generating Facility with the Transmission System.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Generating Facility to which Project Developer has granted a mortgage or other lien as security for some or all of Project Developer's obligations under the corresponding power purchase agreement.

Project Identifier:

"Project Identifier" shall mean, when an Application from a Project Developer or an Eligible Customer results in a valid New Service Request, in accordance with Tariff, Part VII, Subpart C, section 306 [or Part VIII, Subpart B, section 403], the assigned Project Identifier to such request as confirmed by Transmission Provider. For Project Developers and Eligible Customers, the Project Identifier will indicate the applicable Cycle, and will denote a number that represents the project within the Cycle. The Project Identifier is strictly for identification purposes, and does not indicate priority within a Cycle.

Provisional Interconnection Service:

"Provisional Interconnection Service" shall mean interconnection service provided by Transmission Provider associated with interconnecting the Project Developer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Qualifying Facility:

"Qualifying Facility" shall mean an electric energy generating facility that complies with the qualifying facility definition established by Public Utility Regulatory Policies Act ("PURPA") and any FERC rules as amended from time to time (18 C.F.R. part 292, section 292.203 et seq.) implementing PURPA and, to the extent required to obtain or maintain Qualifying Facility status, is self-certified as a Qualifying Facility or is certified as a Qualified Facility by the FERC.

Readiness Deposit:

"Readiness Deposit" shall mean the deposit or deposits required by Tariff, Part VII, Subpart A, section 301(A)(3)(b).

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party under the Tariff, Part VII, a Generation Interconnection Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Request Number:

"Request Number" shall mean, when an Application from an Upgrade Customer results in a valid Upgrade Request, in accordance with Tariff, Part VII, section 337 [or Part VIII, Subpart H, section 435], the assigned Request Number to such request as confirmed by Transmission Owner. The Request Number will indicate the serial position and priority.

RRI:

"RRI" shall mean the Reliability Resource Initiative, a PJM initiative in 2024.

RRI Deposit:
"RRI Deposit" shall mean the deposit required by Tariff, Part VII, Subpart C, section 306(E)(1)(a).

RRI ELCC Class Rating:

"RRR ELCC Class Rating" shall mean the rating set forth in Tariff, Part VII, Subpart C, section 306(E)(4)(a)(ii).

RRI Projects:

"RRI Projects" shall mean those Generation Interconnection Requests eligible to apply for participation in Transition Cycle #2 pursuant to Tariff, Part VII, Subpart C, sections 305(B) and 306(E).

RRI Sunset Date:

"RRI Sunset Date" shall mean the date at which all projects, including RRI Projects, in Transition Cycle #2 either have effective Generation Interconnection Agreements or Wholesale Market Participation Agreements or have withdrawn or been terminated, and is the date the provisions of

Tariff, Part VII, Subpart C, section 305(B) and Tariff, Part VII, Subpart C, sections 306(E)(1) through (4) shall sunset and no longer apply.

RRI Unforced Capacity:

"RRI Unforced Capacity" shall mean the Unforced Capacity amount determined as set forth in Tariff, Part VII, Subpart C, section 306(E)(4)(a)(i).

RRI Uprate:

"RRI Uprate" shall mean, solely for purposes of Tariff, Part VII, Subpart C, section 306(E), a project for which a Generation Interconnection Request has been submitted to increase the generation capacity of a Base Project.

Schedule of Work:

"Schedule of Work" shall mean that Schedule of Work set forth in GIA, Schedule L, section 8.0, or CSA, Appendix I, as applicable, setting forth the timing of work to be performed by the Constructing Entity(ies), based upon the System Impact Study(ies) and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work set forth in GIA, Specifications, section 3.0 to be performed by the Constructing Entity(ies) or scope of work set forth in CSA, Schedule C, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Security:

"Security" shall mean the financial guaranty provided by the Project Developer, Eligible Customer or Upgrade Customer pursuant to Tariff, Part VII, Subpart D, section 309(A)(2)(i), and Tariff, Part VII, Subpart D, section 309(A)(3)(a), and Tariff VII, Subpart D, section 311(a)(2)(d)(i)(a), and Tariff, Part VII, Subpart D, section 311(A)(2)(h), and Tariff, Part VII, Subpart D, section 313(A)(1)(a), to secure the Project Developer's, Eligible Customer's or Upgrade Customer responsibility for Costs under an interconnection-related agreement set forth in Tariff, Part IX.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Site:

"Site" shall mean all of the real property including, but not limited to, any owned or leased real property, bodies of water and/or submerged land, and easements, or other forms of property rights acceptable to PJM, on which the Generating Facility or Merchant Transmission Facility is situated and/or on which the Project Developer Interconnection Facilities are to be located.

Site Control:

"Site Control" shall mean the evidentiary documentation provided by Project Developer in relation to a New Service Request demonstrating the requirements as set forth in Tariff, Part VII, Subpart A, section 302, and Tariff, Part VII, Subpart C, section 306, and Tariff, Part VII, Subpart D, section 309, and Tariff, Part VII, Subpart D, section 313.

Stand Alone Network Upgrades:

"Stand Alone Network Upgrades" shall mean Network Upgrades, which are not part of an Affected System, which a Project Developer may construct without affecting day-to-day operations of the Transmission System during their construction. Transmission Provider, Transmission Owner and Project Developer must agree as to what constitutes Stand Alone Network Upgrades and identify them in GIA, Specifications, section 3.0. If the Transmission Provider or Transmission Owner and Project Developer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider or Transmission Owner that disagrees with the Project Developer must provide the Project Developer a written technical explanation outlining why the Transmission Provider or Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Study Deposit:

"Study Deposit" shall mean the payment in the form of cash required to initiate and fund any study provided for in Tariff, Part VII, Subpart A, section 301(A)(3)(a).

Surplus Project Developer:

"Surplus Project Developer" shall mean either a Project Developer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region.

Surplus Service Request Number:

"Surplus Service Request Number" shall mean, when an Application from a Surplus Interconnection Service Customer results in a valid Surplus Interconnection Service Request, in accordance with Tariff, Part VIII, Subpart E, section 414, the assigned Surplus Service Request Number to such request as confirmed by Transmission Provider. The Request Number will indicate the serial position and priority.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in a Generation Interconnection Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Surplus Interconnection Study Agreement:

"Surplus Interconnection Study Agreement" shall mean the form of the Surplus Interconnection Study Agreement set forth in Tariff, Part IX, Subpart I.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Transmission Owners and Project Developer as they may be amended from time to time.

System Impact Study:

"System Impact Study" shall mean an assessment(s) by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a New Service Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate a New Service Request, and (iii) an estimated date that the New Service Requests can be interconnected with the Transmission System and an estimate of the cost responsibility for the interconnection of the New Service Request; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Generating Facility, and (ii) the Generating Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Generating Facility.

Transition Date:

"Transition Date" shall mean the later of: (i) the effective date of Transmission Provider's Docket Nos. ER22-2110-000, -001 transition cycle filing seeking FERC acceptance of this Tariff, Part VII or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Project Developer pursuant to Tariff, Part VII, Subpart C, section 306(A)(4) to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Project Developer Interconnection Facilities and that, after the transfer under GIA, Appendix 2, section 23.3.5 to the Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Project Developer constructed, are owned, controlled, operated and maintained by the Transmission Owner on the Transmission Owner's side of the Point of Change in Ownership identified in appendices to the Generation Interconnection Agreement and if applicable, the Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Generating Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrades:

"Transmission Owner Upgrades" shall mean Distribution Upgrades, Merchant Transmission Upgrades, Network Upgrades and Stand-Alone Network Upgrades.

Transmission Project Developer:

"Transmission Project Developer" shall mean an entity that submits a request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Upgrade Customer:

"Upgrade Customer" shall mean an entity that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8, or that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Part IX, Subpart K, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Valid Upgrade Request:

"Valid Upgrade Request" shall mean an Upgrade Request that has been determined by Transmission Provider to meet the requirements of Tariff, Part VII, Subpart C, section 306 (application requirements).

Wholesale Market Participation Agreement ("WMPA"):

"Wholesale Market Participation Agreement" ("WMPA") shall mean the form of agreement intended to allow a Project Developer to effectuate in wholesale sales in the PJM markets. A form of the WMPA is set forth in Tariff, Part IX, Subpart C.

Wholesale Transaction:

"Wholesale Transaction" shall mean any transaction involving the transmission or sale for resale of electricity in interstate commerce that utilizes any portion of the Transmission System.

APPENDIX 2

STANDARD TERMS AND CONDITIONS FOR INTERCONNECTIONS

1 Commencement, Term of and Conditions Precedent to Interconnection Service

1.1 Commencement Date:

The effective date of a Generation Interconnection Agreement shall be the date provided in section 4.0 of the Generation Interconnection Agreement. Interconnection Service under this Generation Interconnection Agreement shall commence upon the satisfaction of the conditions precedent set forth in section 1.2 below.

1.2 Conditions Precedent:

The following conditions must be satisfied prior to the commencement of Interconnection Service under this Generation Interconnection Agreement:

(a) This Generation Interconnection Agreement, if filed with FERC, shall have been accepted for filing by the FERC;

(b) All requirements for Initial Operation as specified in section 1.4 below shall have been met and Initial Operation of the Generating Facility or Merchant Transmission Facility shall have been completed.

(c) Project Developer shall be in compliance with all Applicable Technical Requirements and Standards for interconnection under the Tariff (as determined by the Transmission Provider).

1.3 Term:

This Generation Interconnection Agreement shall remain in full force and effect until it is terminated in accordance with section 16 of this Appendix 2.

1.4 Initial Operation:

The following requirements shall be satisfied prior to Initial Operation of the Generating Facility or Merchant Transmission Facility:

1.4.1 The construction of all Interconnection Facilities and Transmission Owner Upgrades necessary for the interconnection of the Generating Facility or Merchant Transmission Facility has been completed;

1.4.2 The Transmission Owner has accepted any Interconnection Facilities and Stand Alone Network Upgrades constructed by Project Developer pursuant to this GIA;

1.4.3 The Project Developer and the Transmission Owner have all necessary systems and personnel in place to allow for parallel operation of their respective facilities;

1.4.4 The Transmission Owner has received all applicable documentation for the Interconnection Facilities built by the Project Developer, certified as correct, including, but not limited to, access to the field copy of marked-up drawings reflecting the as-built condition, pre-operation test reports, and instruction books; and

1.4.5 Project Developer shall have received any necessary authorization from Transmission Provider to synchronize with the Transmission System or to energize, as applicable per the determination of Transmission Provider, the Generating Facility or Merchant Transmission Facility and Interconnection Facilities.

1.4A Other Interconnection Options

1.4A.1 Limited Operation:

If any of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades are not reasonably expected to be completed prior to the Project Developer's planned date of Initial Operation, and provided that the Transmission Owner has accepted the Project Developer Interconnection Facilities pursuant to this GIA, Transmission Provider shall, upon the request and at the expense of Project Developer, perform appropriate power flow or other operating studies on a timely basis to determine the extent to which the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities may operate prior to the completion of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and the Generation Interconnection Agreement. In accordance with the results of such studies and subject to such conditions as Transmission Provider determines to be reasonable and appropriate, Transmission Provider shall (a) permit Project Developer to operate the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities, and (b) grant Project Developer limited, interim Interconnection Rights commensurate with the extent to which operation of the Generating Facility or Merchant Transmission Facility is permitted.

1.4A.2 Provisional Interconnection Service:

Upon the request of Project Developer, and prior to completion of requisite Interconnection Facilities, Distribution Upgrades, Network Upgrades, Stand Alone Network Upgrades, or system protection facilities Project Developer may request limited Interconnection Service at the discretion of Transmission Provider based upon an evaluation that will consider the results of available studies, which terms shall be memorialized in the Generation Interconnection Agreement to be tendered by Transmission Provider to Project subject to the execution timelines and provisions set forth in Tariff, Part IX, section 500.

Transmission Provider shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Project Developer interconnects without modifications to the Generating Facility or Merchant Transmission Facility or the Transmission System. Transmission Provider shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or Stand Alone Network Upgrades, or system protection facilities that are necessary to meet the requirements of NERC, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Generating Facility or Merchant Transmission Facility are in place prior to the commencement of Interconnection Service from the Generating Facility or Merchant Transmission Facility. Where available studies indicate that such Interconnection Facilities, Network Upgrades, Distribution Upgrades, or Stand Alone Network Upgrades, and/or system protection facilities that are required for the interconnection of a new, modified and/or expanded Generating Facility or Merchant Transmission Facility are not currently in place, Transmission Provider will perform a study, at the Project Developer's expense, to confirm the facilities that are required for Provisional Interconnection Service. The maximum permissible output of the Generating Facility or Merchant Transmission Facility shall be studied and updated annually and at the Project Developer's expense. The results will be communicated to the Project Developer in writing upon completion of the study. Project Developer assumes all risk and liabilities with respect to the Provisional Interconnection Service, including changes in output limits and Interconnection Facilities, Network Upgrades, Distribution Upgrades, or Stand Alone Network Upgrades, and/or system protection facilities cost responsibilities.

1.5 Survival:

The Generation Interconnection Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while the Generation Interconnection Agreement was in effect; and to permit each Interconnection Party to have access to the real property, including but not limited to leased property and easements of the other Interconnection Parties pursuant to section 16 of this Appendix 2 to disconnect, remove or salvage its own facilities and equipment.

2 Interconnection Service

2.1 Scope of Service:

Interconnection Service shall be provided to the Project Developer at the Point of Interconnection (a) in the case of interconnection of the Generating Facility of a Generation Project Developer, up to the Maximum Facility Output, and (b) in the case of interconnection of the Merchant Transmission Facility of a Transmission Project Developer, up to the Nominal Rated Capability. The location of the Point of Interconnection shall be mutually agreed by the Interconnected Entities, provided, however, that if the Interconnected Entities are unable to agree on the Point of Interconnection, the Transmission Provider shall determine the Point of Interconnection, provided that Transmission Provider shall not select a Point of Interconnection that would impose excessive costs on either of the Interconnected Entities and shall take material system reliability considerations into account in such selection. Specifications for the Generating Facility or Merchant Transmission Facility and the location of the Point of Interconnection shall be set forth in an appendix to the Generation Interconnection Agreement and shall conform to those stated in the System Impact Study(ies).

2.2 Non-Standard Terms:

The standard terms and conditions of this Appendix 2 shall not apply, to such extent as Transmission Provider determines to be reasonably necessary to accommodate such circumstances, in the event that the Project Developer acquires an ownership interest in facilities which, under the standard terms and conditions of this GIA would be part of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades. In such circumstances and to the extent determined by Transmission Provider to be reasonably necessary, non-standard terms and conditions mutually agreed upon by all Interconnection Parties shall apply, subject to FERC and any other necessary regulatory acceptance or approval. In addition, a Project Developer that acquires an ownership interest in such facilities shall become, and shall remain for so long as it retains such interest, a signatory to the Consolidated Transmission Owners Agreement.

2.3 No Transmission Services:

The execution of a Generation Interconnection Agreement does not constitute a request for transmission service, or entitle Project Developer to receive transmission service, under Part II or Part III of the Tariff. Nor does the execution of a Generation Interconnection Agreement obligate the Transmission Owner or Transmission Provider to procure, supply or deliver to Project Developer or the Generating Facility or Merchant Transmission Facility any energy, capacity, Ancillary Services or Station Power (and any associated distribution services).

2.4 Use of Distribution Facilities:

To the extent that a Generation Project Developer uses distribution facilities for the purpose of delivering energy to the Transmission System, Interconnection Service under this Tariff shall include the construction and/or use of such distribution facilities. In such cases, to such extent as Transmission Provider determines to be reasonably necessary to accommodate such circumstances, the Generation Interconnection Agreement may include non-standard terms and conditions mutually agreed upon by all Interconnection Parties as needed to conform with Applicable Laws and Regulations and Applicable Standards relating to such distribution facilities.

3 Modification of Facilities

3.1 General:

Subject to Applicable Laws and Regulations and to any applicable requirements or conditions of the Tariff and the Operating Agreement, either Interconnected Entity may undertake modifications to its facilities ("Planned Modifications"). In the event that an Interconnected Entity plans to undertake a modification, that Interconnected Entity, in accordance with Good Utility Practice, shall provide notice to the other Interconnection Parties with sufficient information regarding such modification, including any modification to its project that causes the project's capacity, location, configuration or technology to differ from any corresponding information provided in the Interconnection Request, so that the other Interconnection Parties may evaluate the potential impact of such modification prior to commencement of the work. The Interconnected Entity may make changes to SCHEDULE A GENERATING FACILITY LOCATION/SITE PLAN and corresponding Site Control parcels provided they demonstrate to Transmission Provider that the change does not adversely impact the timing of milestones or Transmission Owner construction schedule. Project Developer shall submit to Transmission Provider an attestation in accordance with the PJM template that the modification to SCHEDULE A will have no impact on the overall timing of milestones (including backfeed date). Additionally, the attestation shall include acknowledgement from Project Developer that they waive the ability to request future milestone extensions related to permits or other land issues. In the event Transmission Provider determines the change impacts modeling assumptions, the Interconnected Entity desiring to perform such modification shall provide the relevant drawings, plans, specifications and models to the other Interconnection Parties in advance of the beginning of the work. Transmission Provider and the applicable Interconnection Entity shall enter into a Necessary Studies Agreement, a form is located in the Tariff, Part IX, pursuant to which Transmission Provider agrees to conduct the necessary studies to determine whether the Planned Modifications will have a permanent material impact on the Transmission System or would constitute a Material Modification, and to identify the additions, modifications, or replacements to the Transmission System, if any, that are necessary, in accordance with Good Utility Practice and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards, to accommodate the Planned Modifications.

The Interconnected Entity shall provide the information required by the Necessary Study Agreement and provide the required deposit. Transmission Provider, upon completion of the Necessary Studies, shall provide the Interconnected Entity (i) the type and scope of the permanent material impact, if any, the Planned Modifications will have on the Transmission System; (ii) the additions, modifications, or replacements to the Transmission System required to accommodate the Planned Modifications; and (iii) a good faith estimate of the cost of the additions, modifications, or replacements to the Transmission System required to accommodate the Planned Modifications. In the event such Planned Modification have a permanent material impact on the Transmission System or would constitute a Material Modification, Project Developer shall then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

3.2 Interconnection Request:

This section 3 shall not apply to any proposed modifications by Project Developer to its facilities for which Project Developer must make an Interconnection Request under the Tariff. In such circumstances, the Project Developer and Transmission Provider shall follow the requirements set forth in the GIP.

3.3 Standards:

Any additions, modifications, or replacements made to an Interconnected Entity's facilities shall be constructed and operated in accordance with Good Utility Practice, Applicable Standards and Applicable Laws and Regulations.

3.4 Modification Costs:

Unless otherwise required by Applicable Laws and Regulations or this Appendix 2 and, with respect to a Transmission Project Developer, subject to the terms of the GIP:

(a) Project Developer shall not be responsible for the costs of any additions, modifications, or replacements that the Transmission Owner in its discretion or at the direction of Transmission Provider makes to the Interconnection Facilities and Transmission Owner Upgrades or the Transmission System in order to facilitate the interconnection of a third party to the Interconnection Facilities and Transmission Owner Upgrades or the Transmission System, or to provide transmission service under the Tariff to a third party.

(b) Project Developer shall be responsible for the costs of any additions, modifications, or replacements to the Interconnection Facilities and Transmission Owner Upgrades or the Transmission System that are required, in accord with Good Utility Practice and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards, in order to accommodate additions, modifications, or replacements made by Project Developer to the Generating Facility or Merchant Transmission Facility or to the Project Developer Interconnection Facilities.

(c) Project Developer shall be responsible for the costs of any additions, modifications, or replacements to the Project Developer Interconnection Facilities or the Generating Facility or Merchant Transmission Facility that are required, in accord with Good Utility Practice and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards, in order to accommodate additions, modifications, or replacements that Transmission Provider or the Transmission Owner makes to the Transmission System or to the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades, but only to the extent that Transmission Provider's or the Transmission Owner's changes to the Transmission System or the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades are made pursuant to Good Utility Practice and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards.

4 Operations

4.1 General:

Each Interconnected Entity shall operate, or shall cause operation of, its facilities in a safe and reliable manner in accord with (i) the terms of this Appendix 2; (ii) Applicable Standards; (iii) applicable rules, procedures and protocols set forth in the Tariff and the Operating Agreement, as any or all may be amended from time to time; (iv) Applicable Laws and Regulations, and (v) Good Utility Practice.

4.1.1 Project Developer Initial Drawings:

On or before the applicable date specified in the Milestones of the Generation Interconnection Agreement, Project Developer shall submit to the Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Project Developer Interconnection Facilities. Transmission Owner and Transmission Provider shall review the drawings to assess the consistency of Project Developer's design of the Project Developer Interconnection Facilities with the design that was analyzed in the planning model as described in PJM Manuals. After consulting with the Transmission Owner, Transmission Provider shall provide comments on the drawings to Project Developer within 45 days after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved. All drawings provided hereunder shall be deemed to be Confidential Information.

4.1.1.1 Effect of Review:

Transmission Owner's and Transmission Provider's reviews of Project Developer's initial drawings of the Project Developer Interconnection Facilities shall not be construed as confirming, endorsing or providing a warranty as to the fitness, safety, durability or reliability of such facilities or the design thereof. At its sole cost and expense, Project Developer shall make such changes to the design of the Project Developer Interconnection Facilities as may reasonably be required by Transmission Provider, in consultation with the Transmission Owner, to ensure that the Project Developer Interconnection Facilities meet Applicable Standards and, to the extent that design of the Project Developer Interconnection Facilities is included in the System Impact Study(ies), to ensure that such facilities conform with the System Impact Study(ies).

4.1.2 Project Developer "As-Built" Drawings:

Within 120 days after the date of Initial Operation, unless the Interconnection Parties agree on another mutually acceptable deadline, the Project Developer shall deliver to the Transmission Provider and the Transmission Owner final, "as-built" drawings, information and documents regarding the Project Developer Interconnection Facilities, including, as and to the extent applicable: a one-line diagram, a site plan showing the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities, plan and elevation drawings showing the layout of the Project Developer Interconnection Facilities, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Project Developer's step-up transformers, the facilities connecting the

Generating Facility or Merchant Transmission Facility to the step-up transformers and the Project Developer Interconnection Facilities, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility or Merchant Transmission Facility. As applicable, the Project Developer shall provide Transmission Provider and the Transmission Owner Specifications for the excitation system, automatic voltage regulator, Generating Facility or Merchant Transmission Facility control and protection settings, transformer tap settings, and communications. Transmission Provider and Transmission Owner shall have the right to review such drawings, and charge Project Developer their actual costs of conducting such review.

4.2 Project Developer Obligations:

Project Developer shall obtain Transmission Provider's approval prior to either synchronizing with the Transmission System or energizing, as applicable per the determination of Transmission Provider, the Generating Facility or Merchant Transmission Facility or, except in an Emergency Condition, disconnecting the Generating Facility or Merchant Transmission Facility from the Transmission System, and shall coordinate such synchronizations, energizations, and disconnections with the Transmission Owner.

4.3 Transmission Project Developer Obligations:

A Transmission Project Developer that will be a Merchant Transmission Provider is subject to the terms and conditions in the GIP.

4.4 Permits and Rights-of-Way:

Each Interconnected Entity at its own expense shall maintain in full force and effect all permits, licenses, rights-of-way and other authorizations as may be required to maintain the Generating Facility or Merchant Transmission Facility and the Interconnection Facilities and Transmission Owner Upgrades that the entity owns, operates and maintains and, upon reasonable request of the other Interconnected Entity, shall provide copies of such permits, licenses, rights-of-way and other authorizations at its own expense to the requesting party.

4.5 No Ancillary Services:

Except as provided in section 4.6 of this Appendix 2, nothing in this Appendix 2 is intended to obligate the Project Developer to supply Ancillary Services to either Transmission Provider or the Transmission Owner.

4.6 Reactive Power and Primary Frequency Response

4.6.1 Reactive Power

4.6.1.1 Reactive Power Design Criteria

4.6.1.1.1 New Facilities:

For all new Generating Facilities to be interconnected pursuant to the Tariff, other than wind-powered and other non-synchronous generation facilities, the Generation Project Developer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at a power factor of at least 0.95 leading to 0.90 lagging. For all new wind-powered and other non-synchronous generation facilities the Generation Project Developer shall design its Generating Facility with the ability to maintain a composite power delivery at a power factor of at least 0.95 leading to 0.95 lagging across the full range of continuous rated power output. For all wind-powered and other non-synchronous generation facilities that submitted a New Services Request on or after November 1, 2016, the power factor requirement shall be measured at the high-side of the facility substation transformers. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two.

For new generation resources of more than 20 MW, other than wind-powered and other non-synchronous Generating Facilities, the power factor requirement shall be measured at the generator's terminals. For new generation resources of 20 MW or less the power factor requirement shall be measured at the Point of Interconnection. Any different reactive power design criteria that Transmission Provider determines to be appropriate for a wind-powered or other non-synchronous generation facility shall be stated in the Generation Interconnection Agreement.

A Transmission Project Developer interconnecting Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities shall design its Generating Facility to maintain a power factor at the Point of Interconnection of at least 0.95 leading and 0.95 lagging, when the Generating Facility is operating at any level within its approved operating range.

4.6.1.1.2 Increases in Generating Capacity or Energy Output:

All increases in the capacity or energy output of any generation facility interconnected with the Transmission System, other than wind-powered and other non-synchronous Generating Facilities, shall be designed with the ability to maintain a composite power delivery at continuous rated power output at a power factor for all incremental MW of capacity or energy output, of at least 1.0 (unity) to 0.90 lagging. Wind-powered generation facilities and other non-synchronous generation facilities that submitted a New Services Request on or after November 1, 2016, shall be designed with the ability to maintain a composite power delivery at a power factor for all incremental MW of capacity or energy output of at least 0.95 leading to 0.95 lagging measured at the high-side of the facility substation transformers across the full range of continuous rated power output. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two.

The power factor requirement associated with increases in capacity or energy output of more than 20 MW to synchronous generation facilities interconnected with the Transmission System shall be measured at the generator's terminals. The power factor requirement associated with increases in capacity or energy output of 20 MW or less to synchronous generation facilities interconnected to the Transmission System shall be measured at the Point of Interconnection; however, if the aggregate capacity or energy output of Generating Facility is or will be more than 20 MW, the power factor requirement shall be measure at the generator's terminals.

4.6.1.2 Obligation to Supply Reactive Power:

Project Developer agrees, as and when so directed by Transmission Provider or when so directed by the Transmission Owner acting on behalf or at the direction of Transmission Provider, to operate the Generating Facility to produce reactive power within the design limitations of the Generating Facility pursuant to voltage schedules, reactive power schedules or power factor schedules established by Transmission Provider or, as appropriate, the Transmission Owner. Transmission Provider shall maintain oversight over such schedules to ensure that all sources of reactive power in the PJM Region, as applicable, are treated in an equitable and not unduly discriminatory manner. Project Developer agrees that Transmission Provider and the Transmission Owner, acting on behalf or at the direction of Transmission Provider, may make changes to the schedules that they respectively establish as necessary to maintain the reliability of the Transmission System.

4.6.1.3 Deviations from Schedules:

In the event that operation of the Generating Facility or Merchant Transmission Facility of a Project Developer causes the Transmission System or the Transmission Owner's facilities to deviate from appropriate voltage schedules and/or reactive power schedules as specified by Transmission Provider or the Transmission Owner's operations control center (acting on behalf or at the direction of Transmission Provider), or that otherwise is inconsistent with Good Utility Practice and results in an unreasonable deterioration of the quality of electric service to other customers of Transmission Provider or the Transmission Owner, the Project Developer shall, upon discovery of the problem or upon notice from Transmission Provider or the Transmission Owner, acting on behalf or at the direction of Transmission Provider, take whatever steps are reasonably necessary to alleviate the situation at its expense, in accord with Good Utility Practice and within the reactive capability of the Generating Facility or Merchant Transmission Facility. In the event that the Project Developer does not alleviate the situation within a reasonable period of time following Transmission Provider's or the Transmission Owner's notice thereof, the Transmission Owner, with Transmission Provider's approval, upon notice to the Project Developer and at the Project Developer's expense, may take appropriate action, including installation on the Transmission System of power factor correction or other equipment, as is reasonably required, consistent with Good Utility Practice, to remedy the situation cited in Transmission Provider's or the Transmission Owner's notice to the Project Developer under this section.

4.6.1.4 Payment for Reactive Power:

Any payments to the Project Developer for reactive power shall be in accordance with Tariff, Schedule 2.

4.6.2 Primary Frequency Response:

Generation Project Developer shall ensure the primary frequency response capability of its

Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Generation Project Developer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Generation Project Developer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Generation Project Developer has synchronized the Generating Facility with the Transmission System, Generation Project Developer shall operate the Generating Facility consistent with the provisions specified in sections 4.6.2.1 and 4.6.2.2 of this agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

4.6.2.1 Governor or Equivalent Controls:

Whenever the Generating Facility is operated in parallel with the Transmission System, Generation Project Developer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Generation Project Developer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Generation Project Developer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Generation Project Developer needs to operate the Generating Facility with its governor or equivalent controls not in service, Generation Project Developer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Generation Project Developer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Generation Project Developer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

4.6.2.2 Timely and Sustained Response:

Generation Project Developer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Generation Project Developer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

4.6.2.3 Exemptions:

Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from sections 4.6.2, 4.6.2.1, and 4.6.2.2 of this agreement. Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in section 4.6.2, but shall be otherwise exempt from the operating requirements in sections 4.6.2, 4.6.2.1, 4.6.2.2, and 4.6.2.4 of this agreement.

4.6.2.4 Energy Storage Resources:

Generation Project Developer interconnecting an Energy Storage Resource shall establish an operating range in Schedule I of this GIA that specifies a minimum state of charge and a maximum state of charge between which the Energy Storage Resource will be required to provide primary frequency response consistent with the conditions set forth in sections 4.6.2, 4.6.2.1, 4.6.2.2, and 4.6.2.3 of this agreement. Schedule I shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the Energy Storage Resource; (5) operational limitations of the Energy Storage Resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Generation Project Developer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Schedule I must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Generation Project Developer's Energy Storage Resource is required to provide timely and sustained primary frequency response consistent with section 4.6.2.2 of this agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the Energy Storage Resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Generation Project Developer's Energy Storage Resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Generation Project Developer's Energy Storage Resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

4.7 Under- and Over-Frequency and Under- and Over- Voltage Conditions:

The Generation Project Developer shall ensure "frequency ride through" capability and "voltage ride through" capability of its Generating Facility. The Generation Project Developer shall enable these capabilities such that its Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to section 1.4.4 of Appendix 2 of this Generation Interconnection Agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Generating Facilities in the PJM Region on a comparable basis. The Generating Facility's protective equipment settings shall comply with the Transmission Provider's automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Generating Facilities in the Balancing Authority on a comparable basis. The term "frequency ride through" as used herein shall mean the ability of a Generation Project Developer's Generating Facility Generating Facility to stay connected to and synchronized with the Transmission System or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Generating Facilities in the PJM Region on a comparable basis. The term "voltage ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Generating Facilities in the PJM Region on a comparable basis.

The Transmission System is designed to automatically activate a load-shed program as required by NERC and each Applicable Regional Entity in the event of an under-frequency system disturbance. A Generation Project Developer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by NERC and each Applicable Regional Entity to ensure "frequency ride through" capability of the Transmission System. The response of a Generation Project Developer's Generating Facility to frequency deviations of predetermined magnitudes, both under-frequency and over-frequency deviations shall be studied and coordinated with the Transmission Provider in accordance with Good Utility Practice.

4.8 System Protection and Power Quality:

4.8.1 System Protection:

Project Developer shall, at its expense, install, operate and maintain such System Protection Facilities as may be required in connection with operation of the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities consistent with Applicable Technical Requirements and Standards. Transmission Owner shall install any System Protection Facilities that may be required, as determined by Transmission Provider, on the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades or the Transmission System in connection with the operation of the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities. Responsibility for the cost of any System Protection Facilities required on the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades or the Transmission System shall be allocated as provided in the GIP.

4.8.2 Power Quality:

The Generating Facility or Merchant Transmission Facility and Project Developer Interconnection Facilities shall not cause excessive deviations from the power quality criteria set forth in the Applicable Technical Requirements and Standards.

4.9 Access Rights:

Each Interconnected Entity shall provide the other Interconnected Entity access to areas under its control as reasonably necessary to permit the other Interconnected Entity to perform its obligations under this Appendix 2, including operation and maintenance obligations. An Interconnected Entity that obtains such access shall comply with all safety rules applicable to the area to which access is obtained. Each Interconnected Entity agrees to inform the other Interconnected Entity's representatives of safety rules applicable to an area.

4.10 Switching and Tagging Rules:

The Interconnected Entities shall comply with applicable Switching and Tagging Rules in obtaining clearances for work or for switching operations on equipment. Such Switching and Tagging Rules shall be developed in accordance with OSHA standards codified at 29 C.F.R. part

1910, or successor standards. Each Interconnected Entity shall provide the other Interconnected Entity a copy of its Switching and Tagging Rules that are applicable to the other Interconnected Entity's activities.

4.11 Communications and Data Protocol:

The Interconnected Entities shall comply with any communications and data protocol that the Transmission Provider may establish.

4.12 Nuclear Generating Facilities:

In the event that the Generating Facility is a nuclear Generating Facility, the Interconnection Parties shall agree to such non-standard terms and conditions as are reasonably necessary to accommodate the Project Developer's satisfaction of Nuclear Regulatory Commission requirements relating to the safety and reliability of operations of such facilities.

5 Maintenance

5.1 General:

Each Interconnected Entity shall maintain, or shall cause the maintenance of, its facilities in a safe and reliable manner in accord with (i) the terms of this Appendix 2; (ii) Applicable Standards; (iii) applicable rules, procedures and protocols set forth in the Tariff and the Operating Agreement, as any or all may be amended from time to time; (iv) Applicable Laws and Regulations, and (v) Good Utility Practice.

5.2 Outage Authority and Coordination:

5.2.1 Coordination:

The Interconnection Parties agree to confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility or Merchant Transmission Facility, the Project Developer Interconnection Facilities and any Transmission Owner Interconnection Facilities. In the event a Construction Service Agreement is required, the Construction Parties acknowledge and agree that certain outages of transmission facilities owned by the Transmission Owner, as more specifically detailed in the Scope of Work, may be necessary in order to complete the process of constructing and installing all Interconnection Facilities. The Interconnection Parties, and where applicable, any Construction Parties, further acknowledge and agree that any such outages shall be coordinated by and through the Transmission Provider.

5.2.2 Authority:

Each Interconnected Entity may, in accordance with Good Utility Practice, remove from service its facilities that may affect the other Interconnected Entity's facilities in order to perform maintenance or testing or to install or replace equipment. Except in the event of an Emergency Condition, the Project Developer proposing to remove such facilities from service shall provide prior notice of such activities to the Transmission Provider and the Transmission Owner, and the Interconnected Entities shall coordinate all scheduling of planned facility outages with Transmission Provider, in accordance with applicable sections of the Operating Agreement, the PJM Manuals and any other applicable operating guidelines or directives of the Transmission Provider. Subject to the foregoing, the Interconnected Entity scheduling a facility outage shall use Reasonable Efforts to coordinate such outage with the other Interconnected Entity's scheduled outages.

5.2.3 Outages Required for Maintenance:

Subject to any necessary approval by Transmission Provider, each Interconnected Entity shall provide necessary equipment outages to allow the other Interconnected Entity to perform periodic maintenance, repair or replacement of its facilities and such outages shall be provided at mutually agreeable times, unless conditions arise which an Interconnected Entity believes, in accordance with Good Utility Practice, may endanger persons or property.

5.2.4 Rescheduling of Planned Outages:

To the extent so provided by the Tariff, the Operating Agreement, and the PJM Manuals, an Interconnected Entity may seek compensation from Transmission Provider for any costs related to rejection by Transmission Provider of a request of such Interconnected Entity for a planned maintenance outage.

5.2.5 Outage Restoration:

If an outage on an Interconnected Entity's facilities adversely affects the other Interconnected Entity's facilities, the Interconnected Entity that owns or controls the facility that is out of service shall use Reasonable Efforts to restore the facility to service promptly.

5.3 Inspections and Testing:

Each Interconnected Entity shall perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility or Merchant Transmission Facility with the Transmission System in a safe and reliable manner. Each Interconnected Entity shall have the right, upon advance written notice, to request reasonable additional testing of an Interconnected Entity's facilities for good cause, as may be in accordance with Good Utility Practice.

5.4 Right to Observe Testing:

Each Interconnected Entity shall notify the other Interconnected Entity in advance of its performance of tests of its portion of the Interconnection Facilities. The other Interconnected Entity shall, at its own expense, have the right, but not the obligation, to:

(a) Observe the other Party's tests and/or inspection of any of its system protection facilities and other protective equipment, including power system stabilizers;

(b) Review the settings of the other Party's system protection facilities and other protective equipment;

(c) Review the other Party's maintenance record relative to the Interconnection Facilities, system protection facilities and other protective equipment; and

(d) Exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party.

5.5 Secondary Systems:

Each Interconnected Entity agrees to cooperate with the other in the inspection, maintenance, and testing of those Secondary Systems directly affecting the operation of an Interconnected Entity's facilities and equipment which may reasonably be expected to affect the other Interconnected Entity's facilities. Each Interconnected Entity shall provide advance notice to the other

Interconnected Entity before undertaking any work on such equipment, especially in electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

5.6 Access Rights:

Each Interconnected Entity shall provide the other Interconnected Entity access to areas under its control as reasonably necessary to permit the other Interconnected Entity to perform its obligations under this Appendix 2, including operation and maintenance obligations. An Interconnected Entity that obtains such access shall comply with all safety rules applicable to the area to which access is obtained. Each Interconnected Entity agrees to inform the other Interconnected Entity's representatives of safety rules applicable to an area.

5.7 Observation of Deficiencies:

If an Interconnection Party observes any Abnormal Condition on, or becomes aware of a lack of scheduled maintenance and testing with respect to, an Interconnection Party's facilities and equipment that might reasonably be expected to adversely affect the observing Interconnection Party's facilities and equipment, the observing Interconnection Party shall provide prompt notice under the circumstances to the appropriate Interconnection Party, and such Interconnection Party shall consider such notice in accordance with Good Utility Practice. Any Interconnection Party's review, inspection, and approval related to the other Interconnection Party's facilities and equipment shall be limited to the purpose of assessing the safety, reliability, protection, and control of the Transmission System and shall not be construed as confirming or endorsing the design of such facilities and equipment, or as a warranty of any type, including safety, durability, or reliability thereof. Notwithstanding the foregoing, the observing Interconnection Party shall have no liability whatsoever for failure to give a deficiency notice to the other Interconnection Party and the Interconnected Entity that owns the relevant Interconnection Facilities and Transmission Owner Upgrades shall remain fully liable for its failure to determine and correct deficiencies and defects in its facilities and equipment.

6 Emergency Operations

6.1 Obligations:

Subject to Applicable Laws and Regulations, each Interconnection Party shall comply with the Emergency Condition procedures of NERC, the Applicable Regional Entity, Transmission Provider, the Transmission Owner and Project Developer.

6.2 Notice:

Each Interconnection Party shall notify the other parties promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect operation of the Generating Facility or Merchant Transmission Facility, the Project Developer Interconnection Facilities, the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades, or the Transmission System. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the facilities and/or operation thereof, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

6.3 Immediate Action:

An Interconnection Party becoming aware of an Emergency Condition may take such action, including disconnection of the Generating Facility or Merchant Transmission Facility from the Transmission System, as is reasonable and necessary in accord with Good Utility Practice (i) to prevent, avoid, or mitigate injury or danger to, or loss of, life or property; (ii) to preserve the reliability of, in the case of Project Developer, the Generating Facility or Merchant Transmission Facility, or, in the case of Transmission Provider or the Transmission Owner, the Transmission System and interconnected sub-transmission and distribution facilities; or (iii) to expedite restoration of service. Unless, in Project Developer's reasonable judgment, immediate action is required to prevent imminent loss of life or property, Project Developer shall obtain the consent of Transmission Provider and the Transmission Owner prior to performing any manual switching operations at the Generating Facility or Merchant Transmission Facility or the Generation Interconnection Facilities. Each Interconnection Party shall use Reasonable Efforts to minimize the effect of its actions during an Emergency Condition on the facilities and operations of the other Interconnection Parties.

6.4 Record-Keeping Obligations:

Each Interconnection Party shall keep and maintain records of actions taken during an Emergency Condition that may reasonably be expected to affect the other parties' facilities and make such records available for audit in accordance with section 19.3 of this Appendix 2.

7 Safety

7.1 General:

Each Interconnected Entity and, as applicable, each Construction Party shall perform all work under this Appendix 2 that may reasonably be expected to affect the other Interconnected Entity and, as applicable, the other Construction Party in accordance with Good Utility Practice and all Applicable Laws and Regulations pertaining to the safety of persons or property. An Interconnected Entity and, as applicable, a Construction Party performing work within the boundaries of the other Interconnected Entity's facilities and, as applicable, the other Construction Party's facilities must abide by the safety rules applicable to the site. Each party agrees to inform the other party's representatives of applicable safety rules that must be obeyed on the premises. A Construction Party performing work within an area controlled by another Construction Party must abide by the safety rules applicable to the area.

7.2 Environmental Releases:

Each Interconnected Entity and, as applicable, each Construction Party shall notify the other Interconnection Parties and, as applicable, Construction Parties, first orally and promptly thereafter in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities, related to the Generating Facility or Merchant Transmission Facility or the Interconnection Facilities and Transmission Owner Upgrades, any of which may reasonably be expected to affect one or both of the other parties. The notifying party shall (i) provide the notice as soon as possible; (ii) make a good faith effort to provide the notice within 24 hours after the party becomes aware of the occurrence; and (iii) promptly furnish to the other parties copies of any publicly available reports filed with any governmental agencies addressing such events.

8 Metering

8.1 General:

Project Developer shall have the right to install, own, operate, test, and maintain the necessary Metering Equipment. In the event that Project Developer exercises this option, the Transmission Owner shall have the right to install its own check meter(s), at its own expense, at or near the location of the Metering Equipment. If both Project Developer and Transmission Owner install meters, the meter installed by the Project Developer shall control unless it is determined by testing to be inaccurate. If the Project Developer does not exercise the option provided by the first sentence of this section, the Transmission Owner shall have the option to install, own, operate, test and maintain all necessary Metering Equipment at Project Developer's expense. If the Transmission Owner does not exercise this option, the Project Developer shall install, own, operate, test and maintain all necessary Metering Equipment. Transmission Provider shall determine the location where the Metering Equipment shall be installed, after consulting with Project Developer and the Transmission Owner. All Metering Equipment shall be tested prior to any operation of the Generating Facility or Merchant Transmission Facility. Power flows to and from the Generating Facility or Merchant Transmission Facility shall be compensated to the Point of Interconnection, or, upon the mutual agreement of the Transmission Owner and the Project Developer, to another location.

8.2 Standards:

All Metering Equipment installed pursuant to this Appendix 2 to be used for billing and payments shall be revenue quality Metering Equipment and shall satisfy applicable ANSI standards and Transmission Provider's metering standards and requirements. Nothing in this Appendix 2 precludes the use of Metering Equipment for any retail services of the Transmission Owner provided, however, that in such circumstances Applicable Laws and Regulations shall control.

8.3 Testing of Metering Equipment:

The Interconnected Entity that, pursuant to section 8.1 of this Appendix 2, owns the Metering Equipment shall operate, maintain, inspect, and test all Metering Equipment upon installation and at least once every two years thereafter. Upon reasonable request by the other Interconnected Entity, the owner of the Metering Equipment shall inspect or test the Metering Equipment more frequently than every two years, but in no event more frequently than three times in any 24-month period. The owner of the Metering Equipment shall give reasonable notice to the Interconnection Parties of the time when any inspection or test of the owner's Metering Equipment shall take place, and the other parties may have representatives present at the test or inspection. If Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced in order to provide accurate metering. Where the Transmission Owner owns the Metering Equipment, the expense of such adjustment, repair or replacement shall be borne by the Project Developer, except that the Project Developer shall not be responsible for such expenses where the inaccuracy or defect is caused by the Transmission Owner. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than 1 percent from the measurement made by the standard meter used in the test, the owner of the Metering Equipment shall inform Transmission Provider, and the Transmission Provider shall inform the other Interconnected Entity, of the need to correct all measurements made by the inaccurate meter for the period during which the inaccurate measurements were made, if the period can be determined. If the period of inaccurate measurement cannot be determined, the correction shall be for the period immediately preceding the test of the Metering Equipment that is equal to one-half of the time from the date of the last previous test of the Metering Equipment, provided that the period subject to correction shall not exceed nine months.

8.4 Metering Data:

At Project Developer's expense, the metered data shall be telemetered (a) to a location designated by Transmission Provider; (b) to a location designated by the Transmission Owner, unless the Transmission Owner agrees otherwise; and (c) to a location designated by Project Developer. Data from the Metering Equipment at the Point of Interconnection shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from or to the Generating Facility or Merchant Transmission Facility to the Point of Interconnection, provided that the Transmission Provider's rules applicable to Station Power as set forth at Tariff, Attachment K-Appendix, section 1.7.10(d) shall control with respect to a Generation Project Developer's consumption of Station Power.

8.5 Communications

8.5.1 Project Developer Obligations:

Project Developer shall install and maintain satisfactory operating communications with Transmission Provider's system dispatcher or its other designated representative and with the Transmission Owner. Project Developer shall provide standard voice line, dedicated voice line, and electronic communications at its Generating Facility or Merchant Transmission Facility control room. Project Developer also shall provide and maintain backup communication links with both Transmission Provider and Transmission Owner for use during abnormal conditions as specified by Transmission Provider and Transmission Owner, respectively. Project Developer further shall provide the dedicated data circuit(s) necessary to provide Project Developer data to the Transmission Provider and Transmission Owner as necessary to conform with Applicable Technical Requirements and Standards.

8.5.2 Remote Terminal Unit:

Unless otherwise deemed unnecessary by Transmission Provider and Transmission Owner, as indicated in the Generation Interconnection Agreement, prior to any operation of the Generating Facility or Merchant Transmission Facility, a remote terminal unit, or equivalent data collection and transfer equipment acceptable to the Interconnection Parties, shall be installed by Project Developer, or by the Transmission Owner at Project Developer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider and Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in section 8.5.1 of this Appendix 2. Instantaneous, bi-directional real power and, with respect to a Generation Project Developer's Generating Facility or Merchant Transmission Facility, reactive power flow information, must be telemetered directly to the location(s) specified by Transmission Provider and the Transmission Owner.

8.5.3 Phasor Measurement Units (PMUs):

A Project Developer entering the New Services Queue on or after October 1, 2012, with a proposed new Generating Facility that has a Maximum Facility Output equal to or greater than 100 MW shall install and maintain, at its expense, phasor measurement units ("PMUs"). PMUs shall be installed on the Generating Facility low side of the generator step-up transformer, unless it is a non-synchronous generation facility, in which case the PMUs shall be installed on the Generating Facility side of the Point of Change in Ownership. The PMUs must be capable of performing phasor measurements at a minimum of 30 samples per second which are synchronized via a high-accuracy satellite clock. To the extent Project Developer installs similar quality equipment, such as relays or digital fault recorders, that can collect data at least at the same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment would satisfy this requirement. As provided for in the PJM Manuals, a Project Developer shall be required to install and maintain, at its expense, PMU equipment which includes the communication circuit capable of carrying the PMU data to a local data concentrator, and then transporting the information continuously to the Transmission Provider; as well as store the PMU data locally for 30 days. Project Developer shall provide to Transmission Provider all necessary and requested information through the Transmission Provider synchrophasor system, including the following: (a) gross MW and MVAR measured at the Generating Facility side of the generator step-up transformer (or, for a non-synchronous generation facility, to be measured at the Generating Facility side of the Point of Interconnection); (b) generator terminal voltage; (c) generator terminal frequency; and (d) generator field voltage and current, where available. The Transmission Provider will install and provide for the ongoing support and maintenance of the network communications linking the data concentrator to the Transmission Provider. Additional details regarding the requirements and guidelines of PMU data and telecommunication of such data are contained in the PJM Manuals.

9 Force Majeure

9.1 Notice:

An Interconnection Party that is unable to carry out an obligation imposed on it by this Appendix 2 due to Force Majeure shall notify the other parties in writing or by telephone within a reasonable time after the occurrence of the cause relied on.

9.2 Duration of Force Majeure:

A party shall not be considered to be in Default with respect to any obligation hereunder, other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other parties in writing as soon as reasonably possible after the occurrence of the cause relied upon. Those notices shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. Written notices given pursuant to this Article shall be acknowledged in writing as soon as reasonably possible. The party affected shall exercise Reasonable Efforts to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance. The party affected has a continuing notice obligation to the other parties, and must update the particulars of the original Force Majeure notice and subsequent notices, in writing, as the particulars change. The affected party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such party shall resume performance and give prompt written notice thereof to the other parties.

9.3 Obligation to Make Payments:

Any Interconnection Party's obligation to make payments for services shall not be suspended by Force Majeure.

9.4 Definition of Force Majeure:

For the purposes of this section, shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental, military, or lawfully established civilian authorities, or any other cause beyond a party’s control that, in any of the foregoing cases, by exercise of due diligence, such party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force majeure does not include (i) a failure of performance that is due to an affected party’s own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected party.

10 Charges

10.1 Specified Charges:

If and to the extent required by the Transmission Owner, after the Initial Operation of the Generating Facility or Merchant Transmission Facility, Project Developer shall pay one or more of the types of recurring charges described in this section to compensate the Transmission Owner for costs incurred in performing certain of its obligations under this Appendix 2. All such charges shall be stated in Schedule E of the Generator Interconnection Agreement. Permissible charges under this section may include:

(a) Administration Charge – Any such charge may recover only the costs and expenses incurred by the Transmission Owner in connection with administrative obligations such as the preparation of bills, the processing of Generating Facility- or Merchant Transmission Facility-specific data on energy delivered at the Point of Interconnection and costs incurred in similar types of administrative processes related to Project Developer's Interconnection Service. An Administration Charge shall not be permitted to the extent that the Transmission Owner's other charges to the Project Developer under the same Generator Interconnection Agreement include an allocation of Transmission Owner's administrative and general expenses and/or other corporate overhead costs.

(b) Metering Charge – Any such charge may recover only the Transmission Owner's costs and expenses associated with operation, maintenance, inspection, testing, and carrying or capital replacement charges for any Metering Equipment that is owned by the Transmission Owner.

(c) Telemetering Charge – Any such charge may recover only the Transmission Owner's costs and expenses associated with operation, maintenance, inspection, testing, and carrying or capital replacement charges for any telemetering equipment that is owned by the Transmission Owner and that is used exclusively in conjunction with Interconnection Service for the Project Developer.

(d) Generating Facility or Merchant Transmission Facility Operations and Maintenance Charge – Any such charge may recover only the Transmission Owner's costs and expenses associated with operation, maintenance, inspection, testing, modifications, taxes, and carrying or capital replacement charges for Transmission Owner Interconnection Facilities and Transmission Owner Upgrades related to the Project Developer's Interconnection Service and that are owned by the Transmission Owner, provided that

(i) any such charge shall exclude costs and expenses associated with Transmission Owner Interconnection Facilities and Transmission Owner Upgrades owned by the Transmission Owner that are radial line facilities that serve load in addition to a Project Developer; and

(ii) except as otherwise provided by Applicable Laws and Regulations, any such charge may include only an allocated share, derived in accordance with the allocations contained in the System Impact Study(ies), of costs and expenses associated with Transmission Owner Interconnection Facilities and Transmission Owner Upgrades owned by the Transmission Owner that are radial line facilities that serve more than one Project Developer. At the discretion of the affected Interconnected Entities, a Generating Facility or Merchant Transmission Facility Operations and Maintenance Charge authorized under this section may apply on a per-incident basis or on a monthly or other periodic basis.

(e) Other Charges – Any other charges applicable to the Project Developer, as mutually agreed upon by the Project Developer and the Transmission Owner.

10.2 FERC Filings:

To the extent required by law or regulation, each Interconnection Party shall seek FERC acceptance or approval of its respective charges or the methodology for the calculation of such charges. If such filing is required, Transmission Owner shall provide Transmission Provider and Project Developer with appropriate cost data, schedules and/or written testimony in support of any charges under this section in such manner and at such time as to allow Transmission Provider to include such materials in its filing of the Generation Interconnection Agreement with the FERC.

11 Security, Billing and Payments

11.1 Recurring Charges Pursuant to section 10:

The following provisions shall apply with respect to recurring charges applicable to Interconnection Service after Initial Operation of the Generating Facility or Merchant Transmission Facility pursuant to section 10 of this Appendix 2.

11.1.1 General:

Except as, and to the extent, otherwise provided in the Generation Interconnection Agreement, billing and payment of any recurring charges applicable to Interconnection Service after Initial Operation of the Generating Facility or Merchant Transmission Facility pursuant to section 10 of this Appendix 2 shall be in accordance with section 7 of the Tariff. The Transmission Owner shall provide Transmission Provider with all necessary information and supporting data that Transmission Provider may reasonably require to administer billing for and payment of applicable charges under this Appendix 2. Transmission Provider shall remit to the Transmission Owner revenues received in payment of Transmission Owner's charges to Project Developer under this Appendix 2 upon Transmission Provider's receipt of such revenues. At Transmission Provider's reasonable discretion, charges to Project Developer and remittances to Transmission Owner under this Appendix 2 may be netted against other amounts owed by or to such parties under the Tariff.

11.1.2 Billing Disputes:

In the event of a billing dispute between Transmission Provider and Project Developer, Transmission Provider shall continue to provide interconnection service under this Appendix 2 as long as Project Developer (i) continues to make all payments not in dispute, and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Project Developer fails to meet these two requirements for continuation of service, then Transmission Provider shall so inform the Interconnection Parties and may provide notice to Project Developer of a Breach pursuant to section 15 of this Appendix 2. Within 30 days after the resolution of the dispute, the Interconnection Party that owes money to the other Interconnection Party shall pay the amount due with interest calculated in accord with section 11.4.

11.2 Costs for Transmission Owner Interconnection Facilities and Transmission Owner Upgrades:

The following provisions shall apply with respect to charges for the Costs of the Transmission Owner for which the Project Developer is responsible.

11.2.1 Adjustments to Security:

The Security provided by Project Developer at or before execution of the Generation Interconnection Agreement (a) shall be reduced as portions of the work are completed, and/or (b) shall be increased or decreased as required to reflect adjustments to Project Developer's cost responsibility, as determined in accordance with the GIP, to correspond with changes in the Scope of Work developed in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

11.2.2 Invoice:

The Transmission Owner shall provide Transmission Provider a quarterly statement of the Transmission Owner's scheduled expenditures during the next three months for, as applicable (a) the design, engineering and construction of, and/or for other charges related to, construction of the Interconnection Facilities and Transmission Owner Upgrades for which the Transmission Owner is responsible under the GIA, or (b) in the event that the Project Developer exercises the Option to Build, for the Transmission Owner's oversight costs (i.e. costs incurred by the Transmission Owner when engaging in oversight activities to satisfy itself that the Project Developer is complying with the Transmission Owner's standards and Specifications for the construction of facilities) associated with Project Developer's building Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades, including but not limited to Costs for tie-in work and Cancellation Costs. Transmission Owner oversight costs shall be consistent with Schedule L of this GIA. Transmission Provider shall bill Project Developer on behalf of the Transmission Owner, for the Transmission Owner's expected Costs during the subsequent three months. Project Developer shall pay each bill within 20 days after receipt thereof. Upon receipt of each of Project Developer's payments of such bills, Transmission Provider shall reimburse the Transmission Owner. Project Developer may request that the Transmission Provider provide a quarterly cost reconciliation. Such a quarterly cost reconciliation will have a one-quarter lag, e.g., reconciliation of Costs for the first calendar quarter of work will be provided at the start of the third calendar quarter of work, provided, however, that section 11.2.3 of this Appendix 2 shall govern the timing of the final cost reconciliation upon completion of the work.

11.2.3 Final Invoice:

Within 120 days after the Transmission Owner completes construction and installation of the Interconnection Facilities and Transmission Owner Upgrades for which the Transmission Owner is responsible under the Generation Interconnection Agreement, Transmission Provider shall provide Project Developer with an accounting of, and the appropriate Interconnection Party, and where applicable, the Construction Party shall make any payment to the other that is necessary to resolve, any difference between (a) Project Developer's responsibility under the Tariff for the actual Cost of such facilities, and (b) Project Developer's previous aggregate payments to Transmission Provider for the Costs of such facilities. Notwithstanding the foregoing, however, Transmission Provider shall not be obligated to make any payment to either the Project Developer or the Transmission Owner that the preceding sentence requires it to make unless and until the Transmission Provider has received the payment that it is required to refund from the Interconnection Party, and where applicable, the Construction Party owing the payment.

11.2.4 Disputes:

In the event of a billing dispute between any of the Interconnection Parties, and where applicable, the Construction Parties, Transmission Provider and the Transmission Owner shall continue to perform their respective obligations pursuant to this Generation Interconnection Agreement and any related Construction Service Agreements so long as (a) Project Developer continues to make all payments not in dispute, and (b) the Security held by the Transmission Provider while the dispute is pending exceeds the amount in dispute, or (c) Project Developer pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Project Developer fails to meet any of these requirements, then Transmission Provider shall so inform the other Interconnection Parties and Construction Parties and Transmission Provider or the Transmission Owner may provide notice to Project Developer of a Breach pursuant to section 15 of this Appendix 2.

11.3 No Waiver:

Payment of an invoice shall not relieve Project Developer from any other responsibilities or obligations it has under this Appendix 2, nor shall such payment constitute a waiver of any claims arising hereunder.

11.4 Interest:

Interest on any unpaid, delinquent amounts shall be calculated in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii) and shall apply from the due date of the bill to the date of payment.

12 Assignment

12.1 Assignment with Prior Consent:

Except as provided in section 12.2 to this Appendix 2, no Interconnection Party shall assign its rights or delegate its duties, or any part of such rights or duties, under the Generation Interconnection Agreement without the written consent of the other Interconnection Parties, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. An Interconnection Party may make an assignment in connection with the sale, merger, or transfer of a substantial portion or all of its properties including the Interconnection Facilities and Transmission Owner Upgrades which it owns or will own upon completion of construction and the transfer of title required as set forth in section 23 of this Appendix 2, so long as the assignee in such a sale, merger, or transfer assumes in writing all rights, duties and obligations arising under this Generation Interconnection Agreement. In addition, the Transmission Owner shall be entitled, subject to Applicable Laws and Regulations, to assign the Generation Interconnection Agreement to any Affiliate or successor that owns and operates all or a substantial portion of the Transmission Owner's transmission facilities.

12.2 Assignment Without Prior Consent

12.2.1 Assignment to Owners:

Project Developer may assign the Generation Interconnection Agreement without the Transmission Owner's or Transmission Provider's prior consent to any Affiliate or person that purchases or otherwise acquires, directly or indirectly, all or substantially all of the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities, provided that prior to the effective date of any such assignment, the assignee shall demonstrate that, as of the effective date of the assignment, the assignee has the technical and operational competence to comply with the requirements of this Generation Interconnection Agreement and assumes in a writing provided to the Transmission Owner and Transmission Provider all rights, duties, and obligations of Project Developer arising under this Generation Interconnection Agreement. However, any assignment described herein shall not relieve or discharge the Project Developer from any of its obligations hereunder absent the written consent of the Transmission Provider, such consent not to be unreasonably withheld, conditioned or delayed. Project Developer shall provide Transmission Provider with notice of any such assignment in accordance with the PJM Manuals.

12.2.2 Assignment to Lenders:

Project Developer may, without the consent of the Transmission Provider or the Transmission Owner, assign the Generation Interconnection Agreement to any Project Finance Entity(ies), provided that such assignment does not alter or diminish Project Developer's duties and obligations under this Generation Interconnection Agreement. If Project Developer provides the Transmission Owner with notice of an assignment to any Project Finance Entity(ies) and identifies such Project Finance Entities as contacts for notice purposes pursuant to section 21 of this Appendix 2, the Transmission Provider or Transmission Owner shall provide notice and reasonable opportunity for such entity(ies) to cure any Breach under this Generation Interconnection Agreement in accordance with this Generation Interconnection Agreement. Transmission Provider or Transmission Owner shall, if requested by such lenders, provide such customary and reasonable documents, including consents to assignment, as may be reasonably requested with respect to the assignment and status of the Generation Interconnection Agreement, provided that such documents do not alter or diminish the rights of the Transmission Provider or Transmission Owner under this Generation Interconnection Agreement, except with respect to providing notice of Breach to a Project Finance Entity. Upon presentation of the Transmission Provider and/or the Transmission Owner's invoice therefor, Project Developer shall pay the Transmission Provider and/or the Transmission Owner's reasonable documented cost of providing such documents and certificates. Any assignment described herein shall not relieve or discharge the Project Developer from any of its obligations hereunder absent the written consent of the Transmission Owner and Transmission Provider.

12.3 Successors and Assigns:

This Generation Interconnection Agreement and all of its provisions are binding upon, and inure to the benefit of, the Interconnection Parties and their respective successors and permitted assigns.

13 Insurance

13.1 Required Coverages For Generation Resources Of More Than 20 Megawatts or Merchant Transmission Facilities:

Each Interconnected Entity and, as applicable, Constructing Entity shall maintain insurance at its own expense as described in paragraphs (a) through (d) below. In addition, if there any construction activities associated with this GIA, each Interconnected Entity and, as applicable, Constructing Entity shall maintain insurance at its own expense as described in paragraph (e). All insurance shall be procured from insurance companies rated "A-", VII, or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities and Transmission Owner Upgrades are or will be located. Failure to maintain required insurance shall be a Breach of the Generation Interconnection Agreement.

(a) Workers Compensation insurance with statutory limits, as required by the state and/or jurisdiction in which the work is to be performed, and employer's liability insurance with limits of not less than one million dollars ($1,000,000).

(b) Commercial General Liability Insurance and/or Excess Liability Insurance covering liability arising out of premises, operations, personal injury, advertising, products and completed operations coverage, independent contractors coverage, liability assumed under an insured contract, coverage for pollution to the extent normally available, and punitive damages to the extent allowable under applicable law, with limits of not less than one million dollars ($1,000,000) per occurrence/one million dollars ($1,000,000) general aggregate/one million dollars ($1,000,000) products and completed operations aggregate.

(c) Business/Commercial Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of not less than one million dollars ($1,000,000) each accident for bodily injury, including death, and property damage.

(d) Excess and/or Umbrella Liability Insurance with a limit of liability of not less than twenty million dollars ($20,000,000) per occurrence. These limits apply in excess of the employer's liability, commercial general liability and business/commercial automobile liability coverages described above. This requirement can be met alone or via a combination of primary, excess and/or umbrella insurance.

(e) In addition, if there are construction activities required in connection with this GIA, the following Professional Liability Insurance requirements shall apply:

Professional Liability, including Contractors Legal Liability, providing errors, omissions and/or malpractice coverage. Coverage shall be provided for the Interconnected Entity or Constructing Entity's duties, responsibilities and performance outlined in Schedule L to this GIA, with limits of liability as follows:

$10,000,000 each occurrence

$10,000,000 aggregate

An Interconnected Entity may meet the Professional Liability Insurance requirements by requiring third-party contractors, designers, or engineers, or other parties that are responsible for design work associated with the transmission facilities or Interconnection Facilities and Transmission Owner Upgrades necessary for the interconnection to procure professional liability insurance in the amounts and upon the terms prescribed by this section 13.1(e), and providing evidence of such insurance to the other Interconnected Entity. Such insurance shall be procured from companies rated "A-", VII, or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities and Transmission Owner Upgrades are located. Nothing in this section relieves the Interconnected Entity from complying with the insurance requirements. In the event that the policies of the designers, engineers, or other parties used to satisfy the Interconnected Entity's insurance obligations under this section become invalid for any reason, including but not limited to, (i) the policy(ies) lapsing or otherwise terminating or expiring; (ii) the coverage limits of such policy(ies) are decreased; or (iii) the policy(ies) do not comply with the terms and conditions of the Tariff; Interconnected Entity shall be required to procure insurance sufficient to meet the requirements of this section, such that there is no lapse in insurance coverage.

13.1A Required Coverages for Generation Resources of 20 Megawatts or Less:

Each Interconnected Entity and, as applicable, Constructing Entity shall maintain the types of insurance as described in section 13.1 paragraphs (a) through (e) in an amount sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. Additional insurance may be required by the Project Developer, as a function of owning and operating a Generating Facility. All insurance shall be procured from insurance companies rated "A-", VII, or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities and Transmission Owner Upgrades are located. Failure to maintain required insurance shall be a Breach of the Generation Interconnection Agreement.

13.2 Additional Insureds:

The Commercial General Liability, Business/Commercial Automobile Liability and Excess and/or Umbrella Liability policies procured by each Interconnected Entity (the "Insuring Interconnected Entity") shall include each other Interconnection Party (the "Insured Interconnection Party"), and its respective officers, agents and employees as additional insureds, and as applicable each other Construction Party ("Insured Construction Party") its officers, agents and employees as additional insureds, providing all standard coverages and covering liability of the Insured Interconnection Party, and as applicable Insured Construction Party arising out of bodily injury and/or property damage (including loss of use) in any way connected with the operations, performance, or lack of performance under this Generation Interconnection Agreement.

13.3 Other Required Terms:

The above-mentioned insurance policies (except workers' compensation) shall provide the following:

(a) Each policy shall contain provisions that specify that it is primary and non-contributory for any liability arising out of that party's negligence, and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Insuring Interconnected Entity shall be responsible for its respective deductibles or retentions.

(b) If any coverage is written on a Claims First Made Basis, continuous coverage shall be maintained or an extended discovery period will be exercised for a period of not less than two years after termination of the Generation Interconnection Agreement.

(c) Provide for a waiver of all rights of subrogation which the Insuring Interconnected Entity's insurance carrier might exercise against the Insured Interconnection Party.

13.3A No Limitation of Liability:

The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnected Entities are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Interconnection Parties under the Generation Interconnection Agreement.

13.4 Self-Insurance:

Notwithstanding the foregoing, each Interconnected Entity may self-insure to meet the minimum insurance requirements of this section 13 of this Appendix 2 to the extent it maintains a self-insurance program, provided that such Interconnected Entity's senior secured debt is rated at investment grade or better by Standard & Poor's and its self-insurance program meets the minimum insurance requirements of this section 13. For any period of time that an Interconnected Entity's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under this section 13. In the event that an Interconnected Entity is permitted to self-insure pursuant to this section, it shall notify the other Interconnection Parties that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in section 13.5 of this Appendix 2.

13.5 Notices; Certificates of Insurance:

All policies of insurance shall provide for 30 days prior written notice of cancellation or material adverse change. If the policies of insurance do not or cannot be endorsed to provide 30 days prior notice of cancellation or material adverse change, each Interconnected Entity shall provide the other Interconnected Entities with 30 days prior written notice of cancellation or material adverse change to any of the insurance required in this agreement. Each Interconnected Entity shall provide the other with certificates of insurance prior to Initial Operation of the Generating Facility or Merchant Transmission Facility and thereafter at such time intervals as they shall mutually agree upon, provided that such interval shall not be less than one year. All certificates of insurance shall indicate that the certificate holder is included as an additional insured under the Commercial General Liability, Business/Commercial Automobile Liability and Excess and/or Umbrella Liability coverages, and that this insurance is primary with a waiver of subrogation included in favor of the other Interconnected Entities.

In the event the construction activities pursuant to Schedule L are required, the following provisions will apply, in addition to the provisions set forth above: Prior to the commencement of work pursuant to Schedule L, the Constructing Entities agree to furnish each other with certificates of insurance evidencing the insurance coverage obtained in accordance with section 13.1 of this Appendix 2.

13.6 Subcontractor Insurance:

In accord with Good Utility Practice, each Interconnected Entity shall require each of its subcontractors to maintain and provide evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding of contractors or subcontractors shall be at the hiring Interconnected Entity's discretion, but regardless of bonding, the hiring principal shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

13.7 Reporting Incidents:

The Interconnection Parties shall report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of the Generation Interconnection Agreement.

14 Indemnity

14.1 Indemnity:

Each Interconnection Party shall indemnify and hold harmless the other Interconnection Parties, and the other Interconnection Parties' officers, shareholders, stakeholders, members, managers, representatives, directors, agents and employees, and Affiliates, from and against any and all loss, liability, damage, cost or expense to third parties, including damage and liability for bodily injury to or death of persons, or damage to property or persons (including reasonable attorneys' fees and expenses, litigation costs, consultant fees, investigation fees, sums paid in settlements of claims, penalties or fines imposed under Applicable Laws and Regulations, and any such fees and expenses incurred in enforcing this indemnity or collecting any sums due hereunder) (collectively, "Loss") to the extent arising out of, in connection with, or resulting from (i) the indemnifying Interconnection Party's breach of any of the representations or warranties made in, or failure of the indemnifying Interconnection Party or any of its subcontractors to perform any of its obligations under, this Generation Interconnection Agreement (including Appendix 2), or (ii) the negligence or willful misconduct of the indemnifying Interconnection Party or its contractors; provided, however, that no Interconnection Party shall have any indemnification obligations under this section 14.1 in respect of any Loss to the extent the Loss results from the negligence or willful misconduct of the Interconnection Party seeking indemnity.

14.2 Indemnity Procedures:

Promptly after receipt by a Person entitled to indemnity ("Indemnified Person") of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in section 14.1 may apply, the Indemnified Person shall notify the indemnifying Interconnection Party of such fact. Any failure of or delay in such notification shall not affect an Interconnection Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Interconnection Party. The Indemnified Person shall cooperate with the indemnifying Interconnection Party with respect to the matter for which indemnification is claimed. The indemnifying Interconnection Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Interconnection Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the indemnifying Interconnection Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the indemnifying Interconnection Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Interconnection Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses. The Indemnified Person shall be entitled, at its expense, to participate in any action, suit or proceeding, the defense of which has been assumed by the indemnifying Interconnection Party. Notwithstanding the foregoing, the indemnifying Interconnection Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the indemnifying Interconnection Party, in such event the indemnifying Interconnection Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be unreasonably withheld, conditioned or delayed.

14.3 Indemnified Person:

If an Indemnified Person is entitled to indemnification under this section 14 as a result of a claim by a third party, and the indemnifying Interconnection Party fails, after notice and reasonable opportunity to proceed under section 14.2 of this Appendix 2, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Interconnection Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

14.4 Amount Owing:

If an indemnifying Interconnection Party is obligated to indemnify and hold any Indemnified Person harmless under this section 14, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

14.5 Limitation on Damages:

Except as otherwise provided in this section 14, the liability of an Interconnection Party under this Appendix 2 shall be limited to direct actual damages, and all other damages at law are waived. Under no circumstances shall any Interconnection Party or its Affiliates, directors, officers, employees and agents, or any of them, be liable to another Interconnection Party, whether in tort, contract or other basis in law or equity for any special, indirect punitive, exemplary or consequential damages, including lost profits. The limitations on damages specified in this section 14.5 are without regard to the cause or causes related thereto, including the negligence of any Interconnection Party, whether such negligence be sole, joint or concurrent, or active or passive. This limitation on damages shall not affect any Interconnection Party's rights to obtain equitable relief as otherwise provided in this Appendix 2. The provisions of this section 14.5 shall survive the termination or expiration of the Generation Interconnection Agreement.

14.6 Limitation of Liability in Event of Breach:

An Interconnection Party ("Breaching Party") shall have no liability hereunder to the other Interconnection Parties, and the other Interconnection Parties hereby release the Breaching Party, for all claims or damages that either of them incurs that are associated with any interruption in the availability of the Generating Facility or Merchant Transmission Facility, Interconnection Facilities and Transmission Owner Upgrades, Transmission System or Interconnection Service or damages to an Interconnection Party's facilities, except to the extent such interruption or damage is caused by the Breaching Party's gross negligence or willful misconduct in the performance of its obligations under this Generation Interconnection Agreement (including Appendix 2).

14.7 Limited Liability in Emergency Conditions:

Except as otherwise provided in the Tariff or the Operating Agreement, no Interconnection Party shall be liable to any other Interconnection Party for any action that it takes in responding to an Emergency Condition, so long as such action is made in good faith, is consistent with Good Utility Practice and is not contrary to the directives of the Transmission Provider or of the Transmission Owner with respect to such Emergency Condition. Notwithstanding the above, Project Developer shall be liable in the event that it fails to comply with any instructions of Transmission Provider or the Transmission Owner related to an Emergency Condition.

15 Breach, Cure and Default

15.1 Breach:

A Breach of this Generation Interconnection Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Appendix 2 or of the other portions of the Generation Interconnection Agreement or any attachments or Schedule hereto, including but not limited to any material breach of a representation, warranty or covenant (other than in subsections (a) and (c)-(e) of this section) made in this Appendix 2 or any provisions of Schedule L;

(c) Assignment of the Generation Interconnection Agreement in a manner inconsistent with its terms;

(d) Failure of an Interconnection Party to provide access rights, or an Interconnection Party's attempt to revoke or terminate access rights, that are provided under this Appendix 2; or

(e) Failure of an Interconnection Party to provide information or data required to be determined under this Appendix 2 to another Interconnection Party for such other Interconnection Party to satisfy its obligations under this Appendix 2.

15.2 Continued Operation:

In the event of a Breach or Default by either Interconnected Entity, and subject to termination of the Generation Interconnection Agreement under section 16 of this Appendix 2, the Interconnected Entities shall continue to operate and maintain, as applicable, such DC power systems, protection and Metering Equipment, telemetering equipment, SCADA equipment, transformers, Secondary Systems, communications equipment, building facilities, software, documentation, structural components, and other facilities and appurtenances that are reasonably necessary for Transmission Provider and the Transmission Owner to operate and maintain the Transmission System and the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades and for Project Developer to operate and maintain the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities, in a safe and reliable manner.

15.3 Notice of Breach:

An Interconnection Party not in Breach shall give written notice of an event of Breach to the Breaching Party, to Transmission Provider and to other persons that the Breaching Party identifies in writing to the other Interconnection Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. In the event of a Breach by Project Developer, Transmission Provider or the Transmission Owner agree to provide notice of such Breach and in the same manner as its notice to Project Developer, to any Project Finance Entity provided that the Project Developer has provided the notifying Interconnection Party with notice of an assignment to such Project Finance Entity(ies) and identifies such Project Finance Entity(ies) as contacts for notice purposes pursuant to section 21 of this Appendix 2.

15.4 Cure and Default:

An Interconnection Party that commits a Breach and does not take steps to cure the Breach pursuant to this section 15.4 is automatically in Default of this Appendix 2 and of the Generation Interconnection Agreement, and its project and this Agreement shall be deemed terminated and withdrawn. Transmission Provider shall take all necessary steps to effectuate this termination, including submitting the necessary filings with FERC.

15.4.1 Cure of Breach:

15.4.1.1 Except for the event of Breach set forth in section 15.1(a) above, the Breaching Interconnection Party (a) may cure the Breach within 30 days of the time the Non-Breaching Party sends such notice; or (b) if the Breach cannot be cured within 30 days, may commence in good faith all steps that are reasonable and appropriate to cure the Breach within such 30 day time period and thereafter diligently pursue such action to completion pursuant to a plan to cure, which shall be developed and agreed to in writing by the Interconnection Parties. Such agreement shall not be unreasonably withheld.

15.4.1.2 In an event of Breach set forth in section 15.1(a), the Breaching Interconnection Party shall cure the Breach within five days from the receipt of notice of the Breach. If the Breaching Interconnection Party is the Project Developer, and the Project Developer fails to pay an amount due within five days from the receipt of notice of the Breach, Transmission Provider may use Security to cure such Breach. If Transmission Provider uses Security to cure such Breach, Project Developer shall be in automatic Default and its project and this Agreement shall be deemed terminated and withdrawn.

15.5 Right to Compel Performance:

Notwithstanding the foregoing, upon the occurrence of a Default, a non-Defaulting Interconnection Party shall be entitled to exercise such other rights and remedies as it may have in equity or at law. Subject to section 20.1, no remedy conferred by any provision of this Appendix 2 is intended to be exclusive of any other remedy and each and every remedy shall be cumulative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue other available remedies.

16 Termination

16.1 Termination of the Generation Interconnection Agreement:

This Generation Interconnection Agreement and Interconnection Service under this Generation Interconnection Agreement may be terminated by the following means:

16.1.1 By Mutual Consent:

Interconnection Service may be terminated as of the date on which the Interconnection Parties mutually agree to terminate the Generation Interconnection Agreement.

16.1.2 By Project Developer:

Subject to its payment of Cancellation Costs, Project Developer may unilaterally terminate the Generation Interconnection Agreement pursuant to Applicable Laws and Regulations upon providing Transmission Provider and the Transmission Owner 60 days prior written notice thereof.

16.1.3 Upon Default of Project Developer:

Transmission Provider may terminate the Generation Interconnection Agreement upon the Default of Project Developer of its obligations under the Generation Interconnection Agreement by providing Project Developer and the Transmission Owner prior written notice of termination.

16.1.4 Cancellation Cost Responsibility upon Termination:

In the event of cancellation pursuant to Appendix 2, section 16.1 of this GIA, Project Developer shall be liable to pay to the Transmission Owner or Transmission Provider all Cancellation Costs in connection with the GIA. Cancellation costs may include costs for Network Upgrades assigned to Project Developer, in accordance with the Tariff and as reflected in this GIA, which remain the responsibility of Project Developer under the Tariff. This shall include costs including, but not limited to, the costs for such Network Upgrades to the extent such cancellation would be a Material Modification, or would have an adverse effect or impose costs on other Project Developers in the Cycle. In the event the Transmission Owner incurs Cancellation Costs, it shall provide the Transmission Provider, with a copy to Project Developer, with a written demand for payment and with reasonable documentation of such Cancellation Costs. Project Developer shall pay the Transmission Provider each bill for Cancellation Costs within 30 days after, as applicable, the Transmission Owner's or Transmission Provider's presentation to Project Developer of written demand therefor, provided that such demand includes reasonable documentation of the Cancellation Costs that the invoicing party seeks to collect. Upon receipt of each of Project Developer's payments of such bills of the Transmission Owner, Transmission Provider shall reimburse the Transmission Owner for Cancellation Costs incurred by the latter.

16.2 Disposition of Facilities upon Termination:

16.2.1 Disconnection:

Upon termination of the Generation Interconnection Agreement in accordance with this section 16, Transmission Provider and/or the Transmission Owner shall, in coordination with Project Developer, physically disconnect the Generating Facility or Merchant Transmission Facility from the Transmission System, except to the extent otherwise allowed by this Appendix 2.

16.2.2 Network Facilities:

At the time of termination, the Transmission Provider and the Interconnected Entities shall keep in place any portion of the Interconnection Facilities and Transmission Owner Upgrades that the Transmission Provider deems necessary for the safety, integrity and/or reliability of the Transmission System. Otherwise, Transmission Provider may, in its discretion, within 30 days following termination of Interconnection Service, require the removal of all or any part of the Interconnection Facilities and Transmission Owner Upgrades.

16.2.2.1: In the event that (i) the Generation Interconnection Agreement and Interconnection Service under this Appendix 2 are terminated and (ii) Transmission Provider determines that some or all of the Interconnection Facilities and Transmission Owner Upgrades that are owned by Project Developer are necessary for the safety, integrity and/or reliability of the Transmission System, Project Developer, subject to Applicable Laws and Regulations, shall transfer to the Transmission Owner title to the Interconnection Facilities and Transmission Owner Upgrades that Transmission Provider has determined to be necessary for the safety, integrity and/or reliability of the Transmission System.

16.2.2.2: In the event that removal of some or all of the Interconnection Facilities and Transmission Owner Upgrades is necessary to maintain compliance with Applicable Standards, Project Developer shall be responsible for the costs of any such removal. Project Developer shall have the right to take or retain title to equipment and/or facilities that are removed pursuant to this section; alternatively, in the event that Project Developer does not wish to retain title to removed equipment and/or facilities that it owns, the Transmission Owner may elect to pay Project Developer a mutually agreed amount to acquire and own such equipment and/or facilities.

16.2.3 Request for Disposition Determination:

Project Developer may request a determination from the Transmission Provider whether any Interconnection Facilities and Transmission Owner Upgrades will be removed in the event of any termination of Interconnection Service to the Generating Facility or Merchant Transmission Facility within the following year. Transmission Provider shall respond to that request no later than 60 days after receipt.

16.3 FERC Approval:

Notwithstanding any other provision of this Appendix 2, no termination hereunder shall become effective until the Interconnected Entities and/or Transmission Provider have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with the

FERC of a notice of termination of the Generation Interconnection Agreement, and acceptance of such notice for filing by the FERC.

16.4 Survival of Rights:

Termination of this Generation Interconnection Agreement shall not relieve any Interconnection Party of any of its liabilities and obligations arising under this Generation Interconnection Agreement (including Appendix 2) prior to the date on which termination becomes effective, and each Interconnection Party may take whatever judicial or administrative actions it deems desirable or necessary to enforce its rights hereunder. Applicable provisions of this Appendix 2 will continue in effect after termination to the extent necessary to provide for final billings, billing adjustments, and the determination and enforcement of liability and indemnification obligations arising from events or acts that occurred while the Generation Interconnection Agreement was in effect.

In the event activities under Schedule L are required, the following provisions will apply, in addition to the provisions set forth above:

The obligations of the Construction Parties hereunder with respect to payments, Cancellation Costs, warranties, liability and indemnification shall survive termination to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while GIA was in effect. In addition, applicable provisions of this GIA will continue in effect after expiration, cancellation or termination to the extent necessary to provide for final billings, payments, and billing adjustments.

17 Confidentiality:

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Interconnection Party providing the information orally informs the Interconnection Party receiving the information that the information is confidential. If requested by any Interconnection Party, the disclosing Interconnection Party shall provide in writing the basis for asserting that the information referred to in this section warrants confidential treatment, and the requesting Interconnection Party may disclose such writing to an appropriate Governmental Authority. Any Interconnection Party shall be responsible for the costs associated with affording confidential treatment to its information.

17.1 Term:

During the term of the Generation Interconnection Agreement, and for a period of three years after the expiration or termination of the Generation Interconnection Agreement, except as otherwise provided in this section 17, each Interconnection Party shall hold in confidence, and shall not disclose to any person, Confidential Information provided to it by any other Interconnection Party.

17.2 Scope:

Confidential Information shall not include information that the receiving Interconnection Party can demonstrate: (i) is generally available to the public other than as a result of a disclosure by the receiving Interconnection Party; (ii) was in the lawful possession of the receiving Interconnection Party on a non-confidential basis before receiving it from the disclosing Interconnection Party; (iii) was supplied to the receiving Interconnection Party without restriction by a third party, who, to the knowledge of the receiving Interconnection Party, after due inquiry, was under no obligation to the disclosing Interconnection Party to keep such information confidential; (iv) was independently developed by the receiving Interconnection Party without reference to Confidential Information of the disclosing Interconnection Party; (v) is, or becomes, publicly known, through no wrongful act or omission of the receiving Interconnection Party or breach of this Appendix 2; or (vi) is required, in accordance with section 17.7 of this Appendix 2, to be disclosed to any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the Generation Interconnection Agreement. Information designated as Confidential Information shall no longer be deemed confidential if the Interconnection Party that designated the information as confidential notifies the other Interconnection Parties that it no longer is confidential.

17.3 Release of Confidential Information:

No Interconnection Party shall disclose Confidential Information to any other person, except to its Affiliates (limited by FERC's Standards of Conduct requirements), subcontractors, employees, consultants or to parties who may be or considering providing financing to or equity participation in Project Developer or to potential purchasers or assignees of Project Developer, on a need-to-know basis in connection with the Generation Interconnection Agreement, unless such person has first been advised of the confidentiality provisions of this section 17 and has agreed to comply with such provisions. Notwithstanding the foregoing, an Interconnection Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this section 17.

17.4 Rights:

Each Interconnection Party retains all rights, title, and interest in the Confidential Information that it discloses to any other Interconnection Party. An Interconnection Party's disclosure to another Interconnection Party of Confidential Information shall not be deemed a waiver by any Interconnection Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

17.5 No Warranties:

By providing Confidential Information, no Interconnection Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Interconnection Party obligates itself to provide any particular information or Confidential Information to any other Interconnection Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

17.6 Standard of Care:

Each Interconnection Party shall use at least the same standard of care to protect Confidential Information it receives as the Interconnection Party uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Interconnection Party may use Confidential Information solely to fulfill its obligations to the other Interconnection Parties under the Generation Interconnection Agreement or to comply with Applicable Laws and Regulations.

17.7 Order of Disclosure:

If a Governmental Authority with the right, power, and apparent authority to do so requests or requires an Interconnection Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Interconnection Party shall provide the Interconnection Party that provided the information with prompt prior notice of such request(s) or requirement(s) so that the providing Interconnection Party may seek an appropriate protective order or waive compliance with the terms of this Appendix 2 or the Generation Interconnection Agreement. Notwithstanding the absence of a protective order or agreement, or waiver, the Interconnection Party that is subjected to the request or order may disclose such Confidential Information which, in the opinion of its counsel, the Interconnection Party is legally compelled to disclose. Each Interconnection Party shall use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

17.8 Termination of Generation Interconnection Agreement:

Upon termination of the Generation Interconnection Agreement for any reason, each Interconnection Party shall, within 10 calendar days of receipt of a written request from another party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure and deletion certified in writing to the requesting party) or to return to the other party, without retaining copies thereof, any and all written or electronic Confidential Information received from the requesting party.

17.9 Remedies:

The Interconnection Parties agree that monetary damages would be inadequate to compensate an Interconnection Party for another Interconnection Party's Breach of its obligations under this section 17. Each Interconnection Party accordingly agrees that the other Interconnection Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Interconnection Party breaches or threatens to breach its obligations under this section 17, which equitable relief shall be granted without bond or proof of damages, and the receiving Interconnection Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed to be an exclusive remedy for the breach of this section 17, but shall be in addition to all other remedies available at law or in equity. The Interconnection Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Interconnection Party, however, shall be liable for indirect, incidental or consequential or punitive damages of any nature or kind resulting from or arising in connection with this section 17.

17.10 Disclosure to FERC or its Staff:

Notwithstanding anything in this section 17 to the contrary, and pursuant to 18 C.F.R. § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Interconnection Parties that is otherwise required to be maintained in confidence pursuant to this Generation Interconnection Agreement, the Interconnection Party, shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Interconnection Party must, consistent with 18 C.F.R. § 388.122, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Interconnection Parties are prohibited from notifying the other Interconnection Parties prior to the release of the Confidential Information to FERC or its staff. An Interconnection Party shall notify the other Interconnection Parties to the Generation Interconnection Agreement when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Interconnection Parties may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

17.11 Non-Disclosure:

Subject to the exception in section 17.10 of this Appendix 2, no Interconnection Party shall disclose Confidential Information of another Interconnection Party to any person not employed or retained by the Interconnection Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Interconnection Party to be required in connection with a dispute between or among the Interconnection Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the Interconnection Party that provided such Confidential Information, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Generation Interconnection Agreement or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. Prior to any disclosures of another Interconnection Party's Confidential Information under this subparagraph, the disclosing Interconnection Party shall promptly notify the other Interconnection Parties in writing and shall assert confidentiality and cooperate with the other Interconnection Parties in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

17.12 Information in the Public Domain:

This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

17.13 Return or Destruction of Confidential Information:

If an Interconnection Party provides any Confidential Information to another Interconnection Party in the course of an audit or inspection, the providing Interconnection Party may request the other party to return or destroy such Confidential Information after the termination of the audit period and the resolution of all matters relating to that audit. Each Interconnection Party shall make Reasonable Efforts to comply with any such requests for return or destruction within 10 days of receiving the request and shall certify in writing to the other Interconnection Party that it has complied with such request.

18 Subcontractors

18.1 Use of Subcontractors:

Nothing in this Appendix 2 shall prevent the Interconnection Parties from utilizing the services of subcontractors as they deem appropriate to perform their respective obligations hereunder, provided, however, that each Interconnection Party shall require its subcontractors to comply with all applicable terms and conditions of this Appendix 2 in providing such services.

18.2 Responsibility of Principal:

The creation of any subcontract relationship shall not relieve the hiring Interconnection Party of any of its obligations under this Appendix 2. Each Interconnection Party shall be fully responsible to the other Interconnection Parties for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made.

18.3 Indemnification by Subcontractors:

To the fullest extent permitted by law, an Interconnection Party that uses a subcontractor to carry out any of the Interconnection Party's obligations under this Appendix 2 shall require each of its subcontractors to indemnify, hold harmless and defend each other Interconnection Party, its representatives and assigns from and against any and all claims and/or liability for damage to property, injury to or death of any person, including the employees of any Interconnection Party or of any Affiliate of any Interconnection Party, or any other liability incurred by the other Interconnection Party or any of its Affiliates, including all expenses, legal or otherwise, to the extent caused by any act or omission, negligent or otherwise, by such subcontractor and/or its officers, directors, employees, agents and assigns, that arises out of or is connected with the operation of the facilities of either Interconnected Entity described in this Appendix 2; provided, however, that no Interconnection Party or Affiliate thereof shall be entitled to indemnity under this section 18.3 in respect of any injury, loss, or damage to the extent that such loss, injury, or damage results from the negligence or willful misconduct of the Interconnection Party or Affiliate seeking indemnity.

18.4 Subcontractors Not Beneficiaries:

No subcontractor is intended to be, or shall be deemed to be, a third-party beneficiary of a Generation Interconnection Agreement.

19 Information Access and Audit Rights

19.1 Information Access:

Consistent with Applicable Laws and Regulations, each Interconnection Party shall make available such information and/or documents reasonably requested by another Interconnection Party that are necessary to (i) verify the costs incurred by the other Interconnection Party for which the requesting Interconnection Party is responsible under this Appendix 2; and (ii) carry out obligations and responsibilities under this Appendix 2, provided that the Interconnection Parties shall not use such information for purposes other than those set forth in this section 19.1 and to enforce their rights under this Appendix 2.

19.2 Reporting of Non-Force Majeure Events:

Each Interconnection Party shall notify the other Interconnection Parties when it becomes aware of its inability to comply with the provisions of this Appendix 2 for a reason other than an event of force majeure as defined in section 9.4 of this Appendix 2. The parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this section shall not entitle the receiving Interconnection Party to allege a cause of action for anticipatory breach of the Generation Interconnection Agreement.

19.3 Audit Rights:

Subject to the requirements of confidentiality under section 17 of this Appendix 2, each Interconnection Party shall have the right, during normal business hours, and upon prior reasonable notice to the pertinent other Interconnection Party, to audit at its own expense the other Interconnection Party's accounts and records pertaining to such Interconnection Party's performance and/or satisfaction of obligations arising under this Appendix 2. Any audit authorized by this section shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Appendix 2. Any request for audit shall be presented to the Interconnection Party to be audited not later than 24 months after the event as to which the audit is sought. Each Interconnection Party shall preserve all records held by it for the duration of the audit period.

20 Disputes

20.1 Submission:

Any claim or dispute that any Interconnection Party may have against another arising out of the Generation Interconnection Agreement may be submitted for resolution in accordance with the dispute resolution provisions of the Tariff.

20.2 Rights Under the Federal Power Act:

Nothing in this section shall restrict the rights of any Interconnection Party to file a complaint with FERC under relevant provisions of the Federal Power Act.

20.3 Equitable Remedies:

Nothing in this section shall prevent any Interconnection Party from pursuing or seeking any equitable remedy available to it under Applicable Laws and Regulations.

21 Notices

21.1 General:

Any notice, demand or request required or permitted to be given by any Interconnection Party to another and any instrument required or permitted to be tendered or delivered by any Interconnection Party, in writing to another shall be provided electronically or may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Interconnection Party, or personally delivered to the Interconnection Party, at the electronic or other address specified in the Generation Interconnection Agreement.

21.2 Emergency Notices:

Moreover, notwithstanding the foregoing, any notice hereunder concerning an Emergency Condition or other occurrence requiring prompt attention, or as necessary during day-to-day operations, may be made by telephone or in person, provided that such notice is confirmed in writing promptly thereafter. Notice in an Emergency Condition, or as necessary during day-to-day operations, shall be provided (i) if by the Transmission Owner, to the shift supervisor at, as applicable, a Generation Project Developer's Generating Facility or a Transmission Project Developer's control center; and (ii) if by the Project Developer, to the shift supervisor at the Transmission Owner's transmission control center.

21.3 Operational Contacts:

Each Interconnection Party shall designate, and provide to each other Interconnection Party contact information concerning, a representative to be responsible for addressing and resolving operational issues as they arise during the term of the Generation Interconnection Agreement.

22 Miscellaneous

22.1 Regulatory Filing:

In the event that this Generation Interconnection Agreement contains any terms that deviate materially from the form included in the Tariff, Transmission Provider shall file the Generation Interconnection Agreement on behalf of itself and the Transmission Owner with FERC as a service schedule under the Tariff within 30 days after execution. Project Developer may request that any information so provided be subject to the confidentiality provisions of GIA, Appendix 2, section 17. A Project Developer shall have the right, with respect to any Generation Interconnection Agreement tendered to it, to request (a) dispute resolution under section 12 of the Tariff or, if concerning the Regional Transmission Expansion Plan, consistent with Schedule 5 of the Operating Agreement, or (b) that Transmission Provider file the agreement unexecuted with FERC. With the filing of any unexecuted Generation Interconnection Agreement, Transmission Provider may, in its discretion, propose to FERC a resolution of any or all of the issues in dispute between or among the Interconnection Parties.

22.2 Waiver:

Any waiver at any time by an Interconnection Party of its rights with respect to a Breach or Default under this Generation Interconnection Agreement or with respect to any other matters arising in connection with this Appendix 2, shall not be deemed a waiver or continuing waiver with respect to any subsequent Breach or Default or other matter.

22.3 Amendments and Rights Under the Federal Power Act:

This Generation Interconnection Agreement may be amended or supplemented only by a written instrument duly executed by all Interconnection Parties. An amendment to the Generation Interconnection Agreement shall become effective and a part of this Generation Interconnection Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Generation Interconnection Agreement shall be construed as affecting in any way any of the rights of any Interconnection Party with respect to changes in applicable rates or charges under section 205 of the Federal Power Act and/or FERC’s rules and regulations thereunder, or any of the rights of any Interconnection Party under section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder. The terms and conditions of this Generation Interconnection Agreement and every appendix referred to therein shall be amended, as mutually agreed by the Interconnection Parties, to comply with changes or alterations made necessary by a valid applicable order of any Governmental Authority having jurisdiction hereof.

22.4 Binding Effect:

This Generation Interconnection Agreement, including this Appendix 2, and the rights and obligations thereunder shall be binding upon, and shall inure to the benefit of, the successors and assigns of the Interconnection Parties.

22.5 Regulatory Requirements:

Each Interconnection Party's performance of any obligation under this Generation Interconnection Agreement for which such party requires approval or authorization of any Governmental Authority shall be subject to its receipt of such required approval or authorization in the form and substance satisfactory to the receiving Interconnection Party, or the Interconnection Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Interconnection Party shall in good faith seek, and shall use Reasonable Efforts to obtain, such required authorizations or approvals as soon as reasonably practicable.

23 Representations and Warranties

23.1 General:

Each Interconnected Entity hereby represents, warrants and covenants as follows with these representations, warranties, and covenants effective as to the Interconnected Entity during the time the Generation Interconnection Agreement is effective:

23.1.1 Good Standing:

Such Interconnected Entity is duly organized or formed, as applicable, validly existing and in good standing under the laws of its State of organization or formation, and is in good standing under the laws of the respective State(s) in which it is incorporated and operates as stated in the Generation Interconnection Agreement.

23.1.2 Authority:

Such Interconnected Entity has the right, power and authority to enter into the Generation Interconnection Agreement, to become a party hereto and to perform its obligations hereunder. The Generation Interconnection Agreement is a legal, valid and binding obligation of such Interconnected Entity, enforceable against such Interconnected Entity in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

23.1.3 No Conflict:

The execution, delivery and performance of the Generation Interconnection Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of the Interconnected Entity, or with any judgment, license, permit, order, material agreement or instrument applicable to or binding upon the Interconnected Entity or any of its assets.

23.1.4 Consent and Approval:

Such Interconnected Entity has sought or obtained, or, in accordance with the Generation Interconnection Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of the Generation Interconnection Agreement and it will provide to any Governmental Authority notice of any actions under this Appendix 2 that are required by Applicable Laws and Regulations.

23.2 Transmission Outages:

23.2.1 Outages; Coordination:

The Construction Parties acknowledge and agree that certain outages of transmission facilities owned by the Transmission Owner, as more specifically detailed in the Scope of Work, may be necessary in order to complete the process of constructing and installing all Interconnection Facilities and Transmission Owner Upgrades. The Construction Parties further acknowledge and agree that any such outages shall be coordinated by and through the Transmission Provider.

23.3 Land Rights; Transfer of Title:

In the event activities under Schedule L of this GIA are required, the following provisions will apply, in addition to the provisions set forth above:

23.3.1 Grant of Easements and Other Land Rights:

Project Developer at its sole cost and expense, shall grant such easements and other land rights to the Transmission Owner over the Site at such times and in such a manner as the Transmission Owner may reasonably require to perform its obligations under the GIA and/or to perform its operation and maintenance obligations under the Generation Interconnection Agreement.

23.3.2 Construction of Facilities on Project Developer Property:

To the extent that the Transmission Owner is required to construct and install any Transmission Owner Interconnection Facilities and Transmission Owner Upgrades on land owned by the Project Developer, the Project Developer, at its sole cost and expense, shall legally transfer to the Transmission Owner all easements and other land rights required pursuant to section 23.1 above prior to the commencement of such construction and installation.

23.3.3 Third Parties:

If any part of the Transmission Owner Interconnection Facilities and/or Network Upgrades is to be installed on property owned or controlled by persons other than Project Developer or Transmission Owner, the Transmission Owner shall at Project Developer's expense use efforts, similar in nature and extent to those that it typically undertakes for its own or affiliated generation, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such person any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Transmission Owner Interconnection Facilities and/or Network Upgrades upon such property.

23.3.4 Documentation:

Project Developer shall prepare, execute and file such documentation as the Transmission Owner may reasonably require to memorialize any easements and other land rights granted pursuant to this section 23.3. Documentation of such easements and other land rights, and any associated filings, shall be in a form acceptable to the Transmission Owner.

23.3.5 Transfer of Title to Certain Facilities Constructed by Project Developer:

Within 30 days after the Project Developer's receipt of notice of acceptance following Stage Two energization of the Interconnection Facilities and Transmission Owner Upgrades, the Project Developer shall deliver to the Transmission Owner, for the Transmission Owner's review and approval, all of the documents and filings necessary to transfer to the Transmission Owner title to any Transmission Owner Interconnection Facilities and Transmission Owner Upgrades constructed by the Project Developer, and to convey to the Transmission Owner any easements and other land rights to be granted by Project Developer in accordance with section 23.3.1 above that have not then already been conveyed. The Transmission Owner shall review and approve such documentation, such approval not to be unreasonably withheld, delayed, or conditioned. Within 30 days after its receipt of the Transmission Owner's written notice of approval of the documentation, the Project Developer, in coordination and consultation with the Transmission Owner, shall make any necessary filings at the FERC or other governmental agencies for regulatory approval of the transfer of title. Within 20 days after the issuance of the last order granting a necessary regulatory approval becomes final (i.e., is no longer subject to rehearing), the Project Developer shall execute all necessary documentation and shall make all necessary filings to record and perfect the Transmission Owner's title in such facilities and in the easements and other land rights to be conveyed to the Transmission Owner. Prior to such transfer to the Transmission Owner of title to the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades built by the Project Developer, the risk of loss or damages to, or in connection with, such facilities shall remain with the Project Developer. Transfer of title to facilities under this section shall not affect the Project Developer's receipt or use of the interconnection rights related to Network Upgrades, Distribution Upgrades, Stand Alone Network Upgrades, or Transmission Owner Interconnection Facilities which it otherwise may be eligible as provided in the GIP.

23.3.6 Liens:

The Project Developer shall take all reasonable steps to ensure that, at the time of transfer of title in the Transmission Owner Interconnection Facilities built by the Project Developer to the Transmission Owner, those facilities shall be free and clear of any and all liens and encumbrances, including mechanics' liens. To the extent that the Project Developer cannot reasonably clear a lien or encumbrance prior to the time for transferring title to the Transmission Owner, Project Developer shall nevertheless convey title subject to the lien or encumbrance and shall indemnify, defend and hold harmless the Transmission Owner against any and all claims, costs, damages, liabilities and expenses (including without limitation reasonable attorneys' fees) which may be brought or imposed against or incurred by Transmission Owner by reason of any such lien or encumbrance or its discharge.

23.4 Warranties:

23.4.1 Project Developer Warranty:

The Project Developer shall warrant that its work (or the work of any subcontractor that it retains) in constructing and installing the Transmission Owner Interconnection Facilities or Stand Alone Network Upgrades that it builds is free from defects in workmanship and design and shall conform to the requirements of this GIA for one year (the "Project Developer Warranty Period") commencing upon the date title is transferred to Transmission Owner in accordance with section 23.3.5 of this Appendix 2. The Project Developer shall, at its sole expense and promptly after notification by the Transmission Owner, correct or replace defective work in accordance with Applicable Technical Requirements and Standards, during the Project Developer Warranty Period. The warranty period for such corrected or replaced work shall be the unused portion of the Project Developer Warranty Period remaining as of the date of notice of the defect. The Project Developer Warranty Period shall resume upon acceptance of such corrected or replaced work. All Costs incurred by Transmission Owner as a result of such defective work shall be reimbursed to the Transmission Owner by the Project Developer on demand; provided that the Transmission Owner submits the demand to the Project Developer within the Project Developer Warranty Period and provides reasonable documentation of the claimed costs. The Transmission Owner's acceptance, inspection and testing, or a third party's inspection or testing, of such facilities pursuant to Schedule L, section 11.9 of this GIA shall not be construed to limit in any way the warranty obligations of the Project Developer, and this provision does not modify and shall not limit the Project Developer's indemnification obligations set forth in Appendix 2, section 14.0 of this GIA.

23.4.2 Manufacturer Warranties:

Prior to the transfer to the Transmission Owner of title to the Transmission Owner Interconnection Facilities built by the Project Developer, the Project Developer shall produce documentation satisfactory to the Transmission Owner evidencing the transfer to the Transmission Owner of all manufacturer warranties for equipment and/or materials purchased by the Project Developer for use and/or installation as part of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades built by the Project Developer.

24 Tax Liability

24.1 Safe Harbor Provisions:

This section 24.1 is applicable only to Project Developers. Provided that Project Developer agrees to conform to all requirements of the Internal Revenue Service ("IRS") (e.g., the "safe harbor" section 118(a) and 118(b) of the Internal Revenue Code of 1986, as amended and interpreted by Notice 2016-36, 2016-25 I.R.B. (6/20/2016)) that would confer nontaxable status on some or all of the transfer of property, including money, by Project Developer to the Transmission Owner for payment of the Costs of construction of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades, the Transmission Owner, based on such agreement and on current law, shall treat such transfer of property to it as nontaxable income and, except as provided in section 24.4.2 below, shall not include income taxes in the Costs of Transmission Owner Interconnection Facilities and Transmission Owner Upgrades that are payable by Project Developer under the Generation Interconnection Agreement. Project Developer shall document its agreement to conform to IRS requirements for such non-taxable status in the Generation Interconnection Agreement, the Construction Service Agreement, and/or applicable agreement.

24.2 Tax Indemnity:

Project Developer shall indemnify the Transmission Owner for any costs that Transmission Owner incurs in the event that the IRS and/or a state department of revenue ("State") determines that the property, including money, transferred by Project Developer to the Transmission Owner with respect to the construction of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades is taxable income to the Transmission Owner. Project Developer shall pay to the Transmission Owner, on demand, the amount of any income taxes that the IRS or a State assesses to the Transmission Owner in connection with such transfer of property and/or money, plus any applicable interest and/or penalty charged to the Transmission Owner. In the event that the Transmission Owner chooses to contest such assessment, either at the request of Project Developer or on its own behalf, and prevails in reducing or eliminating the tax, interest and/or penalty assessed against it, the Transmission Owner shall refund to Project Developer the excess of its demand payment made to the Transmission Owner over the amount of the tax, interest and penalty for which the Transmission Owner is finally determined to be liable. Project Developer's tax indemnification obligation under this section shall survive any termination of the Generation Interconnection Agreement or Construction Service Agreement.

24.3 Taxes Other Than Income Taxes:

Upon the timely request by Project Developer, and at Project Developer's sole expense, the Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against the Transmission Owner for which Project Developer may be required to reimburse Transmission Provider under the terms of this Appendix 2 or the GIP. Project Developer shall pay to the Transmission Owner on a periodic basis, as invoiced by the Transmission Owner, the Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Project Developer and the Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Project Developer to the Transmission Owner for such contested taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Project Developer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by the Transmission Owner.

24.4 Income Tax Gross-Up:

24.4.1 Additional Security:

In the event that Project Developer does not provide the safe harbor documentation required under section 24.1 prior to execution of the Generation Interconnection Agreement, within 15 days after such execution, Transmission Provider shall notify Project Developer in writing of the amount of additional Security that Project Developer must provide. The amount of Security that a Transmission Project Developer must provide initially pursuant to this Generation Interconnection Agreement shall include any amounts described as additional Security under this section 24.4 regarding income tax gross-up.

24.4.2 Amount:

The required additional Security shall be in an amount equal to the amount necessary to gross up fully for currently applicable federal and state income taxes the estimated Costs of any Transmission Owner Interconnection Facilities, Distribution Upgrades and/or Network Upgrades for which Project Developer previously provided Security. Accordingly, the additional Security shall equal the amount necessary to increase the total Security provided to the amount that would be sufficient to permit the Transmission Owner to receive and retain, after the payment of all applicable income taxes ("Current Taxes") and taking into account the present value of future tax deductions for depreciation that would be available as a result of the anticipated payments or property transfers (the "Present Value Depreciation Amount"), an amount equal to the estimated Costs of Transmission Owner Interconnection Facilities, Distribution Upgrades and/or Network Upgrades for which Project Developer is responsible under the Generation Interconnection Agreement. For this purpose, Current Taxes shall be computed based on the composite federal and state income tax rates applicable to the Transmission Owner at the time the additional Security is received, determined using the highest marginal rates in effect at that time (the "Current Tax Rate"); and the Present Value Depreciation Amount shall be computed by discounting the Transmission Owner's anticipated tax depreciation deductions associated with such payments or property transfers by its current weighted average cost of capital.

24.4.3 Time for Payment:

Project Developer must provide the additional Security, in a form and with terms as required by the GIP within 15 days after its receipt of Transmission Provider's notice under this section.

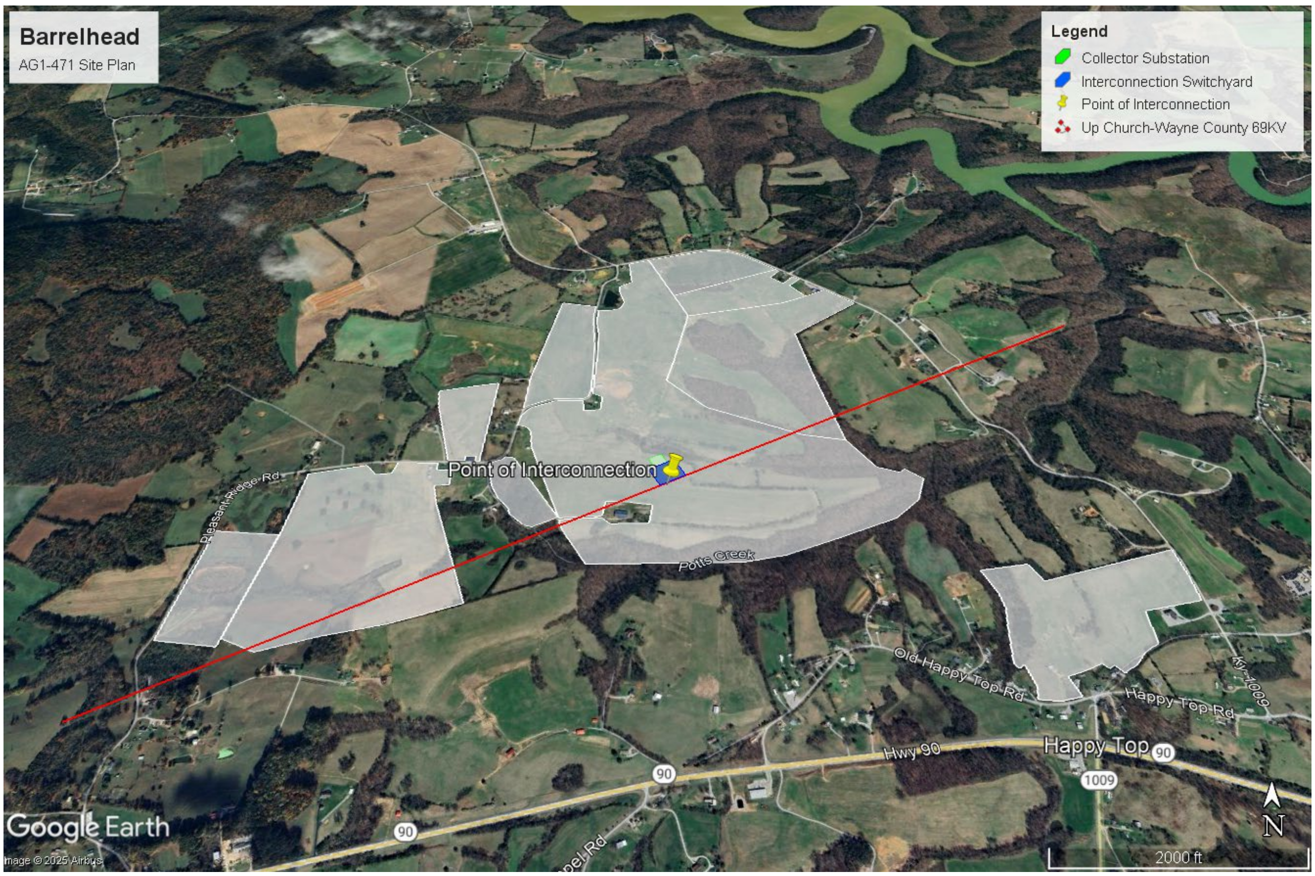
24.5 Tax Status:

Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Generation Interconnection Agreement or the GIP is intended to adversely affect any Transmission Owner's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

SCHEDULE A

GENERATING FACILITY LOCATION/SITE PLAN

36.774310, -85.007715
Alpha, Wayne County, Kentucky

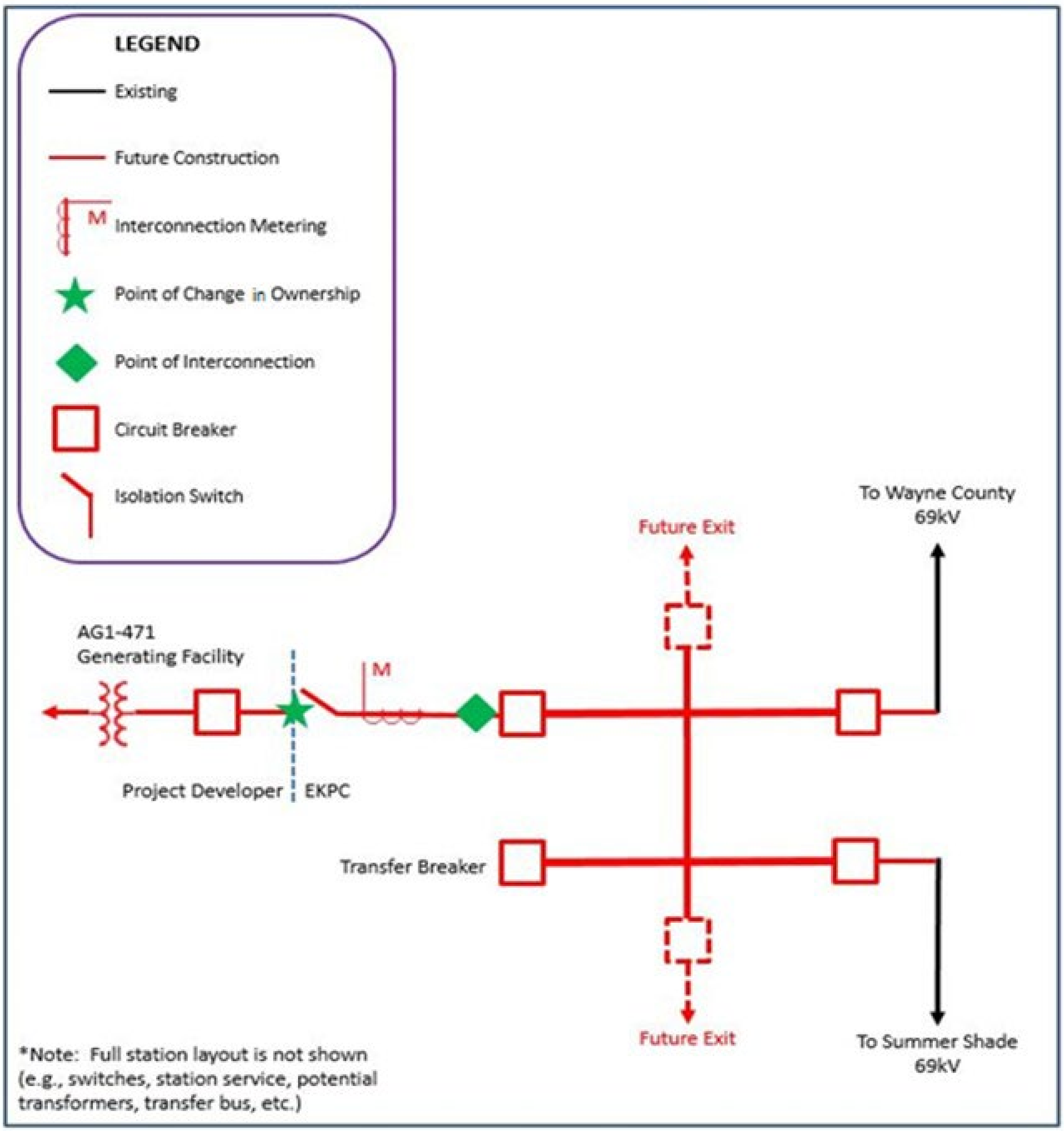


SCHEDULE B

SINGLE-LINE DIAGRAM

AG1-471 Conceptual One-Line Diagram of Interconnection Facilities

Massingale Road 69kV Switch Station



SCHEDULE C

LIST OF METERING EQUIPMENT

Project Developer shall install the necessary equipment to provide "Revenue Metering (KWH, KVARH)" and real time data (KW, KVAR) for the Project Developer's Generating Facility that comply with the requirements set forth in Sections 8.1 through 8.5 of Appendix 2 to this GIA.

REVENUE METERING

At the Project Developer's expense, the Transmission Owner will supply and own at the Point of Interconnection bi-directional revenue metering equipment that will provide the following data:

a. Hourly compensated MWh received from the Generating Facility to the Transmission Owner;
b. Hourly compensated MVARh received from the Generating Facility to the Transmission Owner;
c. Hourly compensated MWh delivered from the Transmission Owner to the Generating Facility; and
d. Hourly compensated MVARh delivered from the Transmission Owner to the Generating Facility.

OPERATIONAL METERING

Instantaneous net MW and MVAR per unit values in accordance with PJM Manuals M-01 and M-14D, and Sections 8.1 through 8.5 of Appendix 2 to this GIA.

COMMUNICATION

Project Developer must provide revenue and real time data to PJM from Project Developer Market Operations Center per PJM Manuals M-01 and M-14D. Project Developer must verify/reconcile revenue and real-time data with Transmission Owner's Market Operations Center prior to submitting to PJM. Any data PJM is collecting can be made available to Transmission Owner via existing PJM net connection.

SCHEDULE D

APPLICABLE TECHNICAL REQUIREMENTS AND STANDARDS

The following Applicable Technical Requirements and Standards shall apply. To the extent that these Applicable Technical Requirements and Standards conflict with the terms and conditions of the Tariff or any other provision of this GIA, the Tariff and/or this GIA shall control.

The EKPC Facility Connection Requirements, rev.15, dated June 1, 2024 shall apply. The EKPC Facility Connection Requirements, rev.15, dated June 1, 2024 is available on the PJM website.

SCHEDULE E

SCHEDULE OF CHARGES

The Administrative, Metering, Telemetering, and Generating Facility Operations and Maintenances ("O&M") Charges referenced below refer to charges described in Section 10.1 of the Standard Terms and Conditions for Interconnections, which are contained in Appendix 2 of this Generation Interconnection Agreement.

ADMINISTRATIVE CHARGES

The charges that EKPC would assess for Administration Charges would be its actual costs.

METERING CHARGES

The charges that EKPC would assess for Metering Charges would be its actual costs.

TELEMETERING CHARGES

The charges that EKPC would assess for Telemetering Charges would be its actual costs.

O&M CHARGES

EKPC reserves the right to charge its actual costs to the Project Developer for O&M expenses to maintain the Project Developer's Interconnection Facilities including metering equipment owned by Transmission Owner.

SCHEDULE F

SCHEDULE OF NON-STANDARD TERMS & CONDITIONS

Louisville Gas & Electric as Affected System Operator:

The System Impact Studies Report for AG1-471 reflects the Affected System study results provided by the Affected System Operator. As identified in the Affected System study results, the AG1-471 project is contingent upon the Affected System upgrades identified below. These results may be subject to adjustments based on the outcome of any remaining phases of the Affected System Operator's Generator Interconnection Process.

The need for any Affected System upgrades shall not delay Initial Operation of a Project Developer's Generating Facility. Notwithstanding the start of Initial Operation, and in accordance with Good Utility Practice, the Generating Facility may be subject to limitations by PJM on its injections and/or withdrawals prior to (1) completion of any remaining studies or necessary restudies by the Affected System Operator; and (2) completion of any Affected System upgrades identified through those studies. Total injections and/or withdrawals may be limited pending coordination and completion of any necessary studies in accordance with the Affected System Operator's Tariff.

Affected System Upgrades with Cost Allocation:

Project Developer has cost responsibility and shall enter into any and all agreements required by Louisville Gas & Electric leading to the study and construction of the following required transmission facilities or upgrades on the Louisville Gas & Electric transmission system in accordance with the Affected System Operator's Tariff. The Generating Facility may also be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of these upgrades:

(Louisville Gas and Electric) Campbellsville 2 Tap - Taylor County 69 kV Line Reconductor
(Louisville Gas and Electric) Lebanon - Springfield 69 kV Line Reconductor
(Louisville Gas and Electric) Morehead W - Morehead 69 kV Line Reconductor
(Louisville Gas and Electric) Shelbyville South - Shelby Co Tap 69 kV Line MOT
(Louisville Gas and Electric) Springfield - North Springfield 69 kV Line MOT
(Louisville Gas and Electric) Brown North - Tyrone 138 kV Line Reconductor

Affected System Upgrades without Cost Allocation:

Additionally, the Generating Facility may be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of the following Affected System upgrades; however, Project Developer does not have cost responsibility for the upgrades:

(None)

Midcontinent Independent System Operator as Affected System Operator:

The System Impact Studies Report for AG1-471 reflects the Affected System study results provided by the Affected System Operator. As identified in the Affected System study results, the AG1-471 project is contingent upon the Affected System upgrades identified below. These results may be subject to adjustments based on the outcome of any remaining phases of the Affected System Operator's Generator Interconnection Process.

The need for any Affected System upgrades shall not delay Initial Operation of a Project Developer's Generating Facility. Notwithstanding the start of Initial Operation, and in accordance with Good Utility Practice, the Generating Facility may be subject to limitations by PJM on its injections and/or withdrawals prior to (1) completion of any remaining studies or necessary restudies by the Affected System Operator; and (2) completion of any Affected System upgrades identified through those studies. Total injections and/or withdrawals may be limited pending coordination and completion of any necessary studies in accordance with the Affected System Operator's Tariff.

Affected System Upgrades with Cost Allocation:

Project Developer has cost responsibility and shall enter into any and all agreements required by Midcontinent Independent System Operator leading to the study and construction of the following required transmission facilities or upgrades on the Midcontinent Independent System Operator transmission system in accordance with the Affected System Operator's Tariff. The Generating Facility may also be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of these upgrades:

(Duke Energy Indiana) Install 28.8 MVAR cap bank at Avon East sub

Affected System Upgrades without Cost Allocation:

Additionally, the Generating Facility may be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of the following Affected System upgrades; however, Project Developer does not have cost responsibility for the upgrades:

(None)

SCHEDULE G

PROJECT DEVELOPER'S AGREEMENT TO CONFORM WITH IRS SAFE HARBOR PROVISIONS FOR NON-TAXABLE STATUS

As provided in section 24.1 of Appendix 2 to this GIA and subject to the requirements thereof, Project Developer represents that it meets all qualifications and requirements as set forth in section 118(a) and 118(b) of the Internal Revenue Code of 1986, as amended and interpreted by Notice 2016-36, 2016-25 I.R.B. (6/20/2016) (the "IRS Notice"). Project Developer agrees to conform with all requirements of the safe harbor provisions specified in the IRS Notice, as they may be amended, as required to confer non-taxable status on some or all of the transfer of property, including money, by Project Developer to Transmission Owner with respect to the payment of the Costs of construction and installation of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades specified in this GIA.

Nothing in Project Developer's agreement pursuant to this Schedule G shall change Project Developer's indemnification obligations under section 24.2 of Appendix 2 to this GIA.

SCHEDULE H

INTERCONNECTION REQUIREMENTS FOR ALL WIND, SOLAR AND NON-SYNCHRONOUS GENERATION FACILITIES

A. Voltage Ride Through Requirements

The Generating Facility shall be designed to remain in service (not trip) for voltages and times as specified for the Eastern Interconnection in Attachment 1 of NERC Reliability Standard PRC-024-1, and successor Reliability Standards, for both high and low voltage conditions, irrespective of generator size, subject to the permissive trip exceptions established in PRC-024-1 (and successor Reliability Standards).

B. Frequency Ride Through Requirements

The Generating Facility shall be designed to remain in service (not trip) for frequencies and times as specified in Attachment 2 of NERC Reliability Standard PRC-024-1, and successor Reliability Standards, for both high and low frequency condition, irrespective of generator size, subject to the permissive trip exceptions established in PRC-024-1 (and successor Reliability Standards).

C. Supervisory Control and Data Acquisition ("SCADA") Capability

The wind, solar or non-synchronous generation facility shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind, solar or non-synchronous generation facility Project Developer shall determine what SCADA information is essential for the proposed wind, solar or non-synchronous generation facility, taking into account the size of the facility and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

D. Meteorological Data Reporting Requirement (Applicable to wind generation facilities only)

The wind generation facility shall, at a minimum, be required to provide the Transmission Provider with site-specific meteorological data including:

- Temperature (degrees Fahrenheit)
- Wind speed (meters/second)
- Wind direction (degrees from True North)
- Atmosphere pressure (hectopascals)
- Forced outage data (wind turbine and MW unavailability)

E. Meteorological Data Reporting Requirement (Applicable to solar generation facilities only)

The solar generation facility shall, at a minimum, be required to provide the Transmission Provider with site-specific meteorological data including:

- Temperature (degrees Fahrenheit)
- Irradiance
- Forced outage data

The Transmission Provider and Project Developer may mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such additional mutually agreed upon requirements for meteorological and forced outage data are set forth below: NOT APPLICABLE UNDER THIS GIA

SCHEDULE I

INTERCONNECTION SPECIFICATIONS FOR AN ENERGY STORAGE RESOURCE

Not Required

SCHEDULE J

SCHEDULE OF TERMS AND CONDITIONS FOR SURPLUS INTERCONNECTION SERVICE

Not Required.

SCHEDULE K

REQUIREMENTS FOR INTERCONNECTION SERVICE BELOW FULL ELECTRICAL GENERATING CAPABILITY

Not Required.

SCHEDULE L

INTERCONNECTION CONSTRUCTION TERMS AND CONDITIONS

INTERCONNECTION CONSTRUCTION TERMS AND CONDITIONS
For the Generation Interconnection Agreement
By and Between
PJM Interconnection, L.L.C.
And
Barrelhead Solar, LLC
And
East Kentucky Power Cooperative, Inc.

(Project Identifier #AG1-471)

1.0 These Interconnection Construction Terms and Conditions ("IC Terms & Conditions"), including the Schedules and Appendices attached hereto or incorporated by reference herein, shall apply to the Generation Interconnection Agreement ("GIA") by and between Transmission Provider, Project Developer, and Transmission Owner. All capitalized terms herein shall have the meanings set forth in Appendix 1 to this Generation GIA.

2.0 The standard terms and conditions for interconnections included in GIA, Appendix 2 associated with this Interconnection Request are hereby specifically incorporated herein.

3.0 Generating Facility or Merchant Transmission Facility. These IC Terms & Conditions specifically relate to the following Generating Facility or Merchant Transmission Facility at the following location:

a. Name of Generating Facility or Merchant Transmission Facility:

Barrelhead

b. Location of Generating Facility or Merchant Transmission Facility:

36.774310, -85.007715
Alpha, Wayne County, Kentucky

4.0 Commencement of Construction.

4.1 The Transmission Owner shall have no obligation to begin construction of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades prior to the Effective Date of this GIA. Construction shall commence as provided in the Schedule of Work set forth in section 8.0 of these IC Terms & Conditions.

5.0 Construction Responsibility for

a. Project Developer Interconnection Facilities. Project Developer is responsible for designing and constructing the Project Developer Interconnection Facilities described in GIA, Specifications, section 3.0(a)(1).

b. Construction of Transmission Owner Interconnection Facilities.

1. The Transmission Owner Interconnection Facilities and Transmission Owner Upgrades for which Transmission Owner shall be responsible for constructing are described in GIA, Specifications, section 3.0(b).

2. Election of Construction Option. Specify below whether the Project Developer and Transmission Owner have mutually agreed to construction of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades that will be built by the Transmission Owner pursuant to the Standard Option or the Negotiated Contract Option.

__X__ Standard Option.

_____ Negotiated Contract Option.

If the parties have mutually agreed to use the Negotiated Contract Option, the permitted, negotiated terms on which they have agreed and which are not already set forth as part of the Scope of Work and/or Schedule of Work set forth in sections 7.0 and 8.0 of these IC Terms & Conditions shall be as set forth in Appendix 1 to this Schedule L.

3. Exercise of Option to Build. Has Project Developer timely exercised the Option to Build?

______ Yes

___X___ No

If Yes is indicated, Project Developer shall build, in accordance with and subject to the conditions and limitations set forth in GIA, Schedule L, section 11.2.3, those portions of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades described in GIA, Specifications, section 3.0(a)(2).

6.0 Facilitation by Transmission Provider: Transmission Provider shall keep itself apprised of the status of the Transmission Owner's and Project Developer's construction-related activities and, upon request of either of them, Transmission Provider shall meet with the Transmission Owner and Project Developer separately or together to assist them in resolving issues between them regarding their respective activities, rights and obligations under this GIA, Schedule L and GIA, Appendix 2. Each of Transmission Owner and Project Developer shall cooperate in good faith with the other in Transmission Provider's efforts to facilitate resolution of disputes.

7.0 Scope of Work. The Scope of Work for all construction shall be as set forth in Specifications, section 3.0 of this GIA, provided, however, that the scope of work is subject to change in accordance with Transmission Provider's scope change process for interconnection projects as set forth in the PJM Manuals. The scope change process is intended to be used for changes to the Scope of Work as defined herein, and is not intended to be used to change any of the milestone set forth in the GIA. Any change to the Scope of Work should be acknowledged by the Parties in a scope change document.

8.0 Schedule of Work. The Schedule of Work for all construction is set forth below, provided, however, that such schedule is subject to change in accordance with section 11.3 of this Schedule L.

Transmission Owner:

Transmission Owner shall commence the scope of work identified in Specifications, section 3.0(b) one month after both full execution of this GIA and completion of the construction kickoff call.

Transmission Owner shall complete all Transmission Owner Interconnection Facilities, Stand Alone Network Upgrades, and Network Upgrades set forth in Specifications, section 3.0(b) of this GIA and provide back feed to Project Developer's Generating Facility by December 15, 2028.

Project Developer:

Project Developer shall commence the scope of work identified in Specifications, section 3.0(a) of this GIA one month after full execution of this GIA and completion of the construction kickoff call.

Project Developer shall complete all Project Developer Interconnection Facilities set forth in Specifications, section 3.0(a) of this GIA and, as applicable, all Transmission Owner Interconnection Facilities, Stand Alone Network Upgrades, and Network Upgrades to be built by Project Developer pursuant to Option to Build set forth in Specifications, section 3.0(a) of this GIA by November 15, 2028.

9.0 If Project Developer exercises the Option to Build, Project Developer shall pay Transmission Owner for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under section 11.2.3.

10.0 Construction Obligations

10.1 Project Developer Obligations: Project Developer shall, at its sole cost and expense, design, procure, construct, own, and install the Generating Facility or Merchant Transmission Facility and the Project Developer Interconnection Facilities in accordance with this GIA, Applicable Standards, Applicable Laws and Regulations, Good Utility Practice, the Scope of Work, and the Facilities Study(ies) and/or System Impact Study(ies) (to the extent that design of the Project Developer Interconnection Facilities is included therein and, except that, in the event of conflict, the Facilities Study and not the System Impact Study will control);

provided, however, that, in the event and to the extent that the Generating Facility or Merchant Transmission Facility is comprised of or includes Merchant Network Upgrades, subject to the terms of GIA, Schedule L, section 11.2.3, the Transmission Owner shall design, procure, construct and install such Merchant Network Upgrades.

10.2 Transmission Owner Interconnection Facilities and Transmission Owner Upgrades

10.2.1 Generally: All Transmission Owner Interconnection Facilities and Transmission Owner Upgrades necessary for the interconnection of the Generating Facility or Merchant Transmission Facility shall be designed, procured, installed and constructed in accordance with this GIA, Applicable Standards, Applicable Laws and Regulations, Good Utility Practice, the Facilities Study(ies) and/or System Impact Study(ies) (except that, in the event of a conflict, the Facilities Study and not the System Impact Study will control), and the Scope of Work.

10.2.2 Cost Responsibility: Responsibility for the Costs of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades shall be assigned in accordance with the GIP, as applicable, and shall be stated in this GIA.

10.2.3 Construction Responsibility: Except as otherwise permitted under, or as otherwise agreed upon by the Project Developer and the Transmission Owner pursuant to this GIA, the Transmission Owner shall be responsible for the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades. In the event that there are multiple Transmission Owners, the Transmission Provider shall determine how to allocate the construction responsibility among them unless they have reached agreement among themselves on how to proceed.

10.2.4 Ownership of Transmission Owner Interconnection Facilities and Transmission Owner Upgrades: The Transmission Owner shall own all Transmission Owner Interconnection Facilities and Transmission Owner Upgrades that it builds. In addition, the Project Developer will convey to the Transmission Owner, as provided in section 23.3.5 of Appendix 2 of this GIA, title to all Transmission Owner Interconnection Facilities and Transmission Owner Upgrades built by the Project Developer pursuant to the terms of this Schedule L. Nothing in this section shall affect the interconnection rights otherwise available to a Transmission Project Developer under the GIP.

10.2A Scope of Applicable Technical Requirements and Standards: Applicable Technical Requirements and Standards shall apply to the design, procurement, construction and installation of the Interconnection Facilities, Transmission Owner Upgrades and Merchant A.C. Transmission Facilities only to the extent that the provisions thereof relate to the design, procurement, construction and/or installation of such facilities. Such provisions relating to the design, procurement, construction and/or installation of facilities shall be appended as Schedule D to this GIA. The Interconnection Parties shall mutually agree upon, or in the absence of such agreement, Transmission Provider shall determine, which provisions of the Applicable Technical Requirements and Standards should be identified in this GIA. In the event of any conflict between the provisions of the Applicable Technical Requirements and Standards that are appended as Schedule D to this GIA and any later-modified provisions that are stated in the pertinent PJM Manual, the provisions appended as Schedule D to this GIA shall control.

10.3 Construction by Project Developer

10.3.1 Construction Prior to Execution of GIA: If the Project Developer procures materials for, and/or commences construction of, the Project Developer Interconnection Facilities, any Transmission Owner Interconnection Facilities or Stand Alone Network Upgrades that it has elected to construct by exercising the Option to Build, or for any subsequent modification thereto, prior to the execution of this GIA or, if this GIA has been executed, before the Transmission Owner and Transmission Provider have accepted the Project Developer's initial design, or any subsequent modification to the design, of such Interconnection Facilities or Stand Alone Network Upgrades, such procurement and/or construction shall be at the Project Developer's sole risk, cost and expense.

10.3.2 Monitoring and Inspection: The Transmission Owner may monitor construction and installation of Interconnection Facilities and Transmission Owner Upgrades that the Project Developer is constructing. Upon reasonable notice, authorized personnel of the Transmission Owner may inspect any or all of such Interconnection Facilities and Transmission Owner Upgrades to assess their conformity with Applicable Standards.

10.3.3 Notice of Completion: The Project Developer shall notify the Transmission Provider and the Transmission Owner in writing when it has completed construction of (i) the Generating Facility or Merchant Transmission Facility; (ii) the Project Developer Interconnection Facilities; and (iii) any Transmission Owner Interconnection Facilities and Stand Alone for which it has exercised the Option to Build.

10.4 Construction-Related Access Rights: The Transmission Owner and the Project Developer herein grant each other at no charge such rights of access to areas that it owns or otherwise controls as may be necessary for performance of their respective obligations, and exercise of their respective rights, pursuant to this Schedule L, provided that either of them performing the construction will abide by the safety, security and work rules applicable to the area where construction activity is occurring.

10.5 Coordination Among Parties: The Transmission Provider, the Project Developer, and all Transmission Owners shall communicate and coordinate their activities as necessary to satisfy their obligations under this Schedule L.

11.0 Construction Requirements

11.1 Construction by Project Developer:

The Project Developer shall use Reasonable Efforts to design, procure, construct and install the Project Developer Interconnection Facilities and any Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that it elects to build by exercise of the Option to Build (defined in section 11.2.3.1 below) in accordance with the Schedule of Work.

11.2 Construction by Transmission Owner

11.2.1 Standard Option:

The Transmission Owner shall use Reasonable Efforts to design, procure, construct and install the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades that it is responsible for constructing in accordance with the Schedule of Work.

11.2.1.1 Construction Sequencing:

In general, the sequence of the proposed dates of Initial Operation of Project Developers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

11.2.2 Negotiated Contract Option:

As an alternative to the Standard Option set forth in section 11.2.1 above, the Transmission Owner and the Project Developer may mutually agree to a Negotiated Contract Option for the Transmission Owner’s design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades. Under the Negotiated Contract Option, the Project Developer and the Transmission Owner may agree to terms different from those included in the Standard Option of section 11.2.1 above and the corresponding standard terms set forth in the applicable provisions of the GIP. Under the Negotiated Contract Option, negotiated terms may include the work schedule applicable to the Transmission Owner’s construction activities and changes to same; payment provisions, including the schedule of payments; incentives, penalties and/or liquidated damages related to timely completion of construction;

use of third party contractors; and responsibility for Costs, but only as between the Project Developer and the Transmission Owner that are parties to this GIA; no other Project Developer's responsibility for Costs under the GIP may be affected. No other terms of the Tariff or this Schedule L shall be subject to modification under the Negotiated Contract Option. The terms and conditions of the Tariff that may be negotiated pursuant to the Negotiated Contract Option shall not be affected by use of the Negotiated Contract Option except as and to the extent that they are modified by the parties' agreement pursuant to such option. All terms agreed upon pursuant to the Negotiated Contract Option are set forth in GIA, Schedule L, Appendix 1. The Negotiated Option can only be used in connection with a Network Upgrade subject to the Network Upgrade Cost Responsibility Agreement if all Project Developers and the relevant Transmission Owner agree.

11.2.3 Option to Build

11.2.3.1 Option:

Project Developer has the option ("Option to Build") to assume responsibility for the design, procurement, and construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in the Schedule of Work in GIA, Schedule L, section 8.0. Transmission Provider and Project Developer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in GIA, Specifications, section 3.0(a)(2). If the Transmission Provider and Project Developer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Project Developer with a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination. Except for Stand Alone Network Upgrades, Project Developer shall have no right to construct Network Upgrades under this option. In order to exercise this Option to Build, Project Developer must provide Transmission Provider and the Transmission Owner with written notice of Project Developer's election to exercise the option consistent with the deadline applicable to its New Service Request or Upgrade Request. Project Developer may not elect Option to Build after such date.

11.2.3.2 General Conditions Applicable to Option:

In addition to the other terms and conditions applicable to the construction of facilities under this Schedule L, the Option to Build is subject to the following conditions:

(a) If the Project Developer assumes responsibility for the design, procurement and construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades:

(i) Project Developer shall engineer, procure equipment, and construct Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(ii) Project Developer's engineering, procurement and construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Owner shall be subject in the engineering, procurement or construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades;

(iii) Transmission Owner shall review and approve engineering design, equipment acceptance tests, and the construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades;

(iv) Prior to commencement of construction, Project Developer shall provide to Transmission Owner a schedule for construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades and shall promptly respond to requests for information from Transmission Owner;

(v) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(vi) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and Specifications provided by Interconnection Transmission Owner, Project Developer shall be obligated to remedy deficiencies in that portion of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades;

(vii) Project Developer shall indemnify Transmission Owner and Transmission Provider for claims arising from Project Developer's construction of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to GIA, Appendix 2, section 14;

(viii) Project Developer shall transfer control of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades to Transmission Owner;

(ix) Unless Parties otherwise agree, Project Developer shall transfer ownership of Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades to Transmission Owner;

(x) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with section 11.2.3.2 of this Schedule L; and

(xi) Project Developer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades are built to the standards and Specifications required by Transmission Provider.

(b) In addition to the General Conditions applicable to Option to Build set forth in section 11.2.3.2(a) above, the following conditions also apply:

(i) The Project Developer must obtain or arrange to obtain all necessary permits and authorizations for the construction and installation of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that it is building, provided, however, that when the Transmission Owner's assistance is required, the Transmission Owner shall assist the Project Developer in obtaining such necessary permits or authorizations with efforts similar in nature and extent to those that the Transmission Owner typically undertakes in acquiring permits and authorizations for construction of facilities on its own behalf;

(ii) The Project Developer must obtain all necessary land rights for the construction and installation of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that it is building, provided, however, that upon Project Developer's reasonable request, the Transmission Owner shall assist the Project Developer in acquiring such land rights with efforts similar in nature and extent to those that the Transmission Owner typically undertakes in acquiring land rights for construction of facilities on its own behalf;

(iii) Notwithstanding anything stated herein, each Transmission Owner shall have the exclusive right and obligation to perform the line attachments (tie-in work), and to calibrate remote terminal units and relay settings, required for the interconnection to such Transmission Owner's existing facilities of any Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that the Project Developer builds; and

(iv) The Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades built by the Project Developer shall be successfully inspected, tested and energized pursuant to sections 11.7 and 11.8 of this Schedule L.

11.2.3.3 Additional Conditions Regarding Network Facilities:

To the extent that the Project Developer utilizes the Option to Build for design, procurement, construction and/or installation of (a) any Transmission Owner Interconnection Facilities that are Stand Alone Network Upgrades to Transmission System facilities that are in existence or under construction by or on behalf of the Transmission Owner on the date that the Project Developer solicits bids under section 11.2.3.7 below, or (b) Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that are to be located on land or in right-of-way owned or controlled by the Transmission Owner, and in addition to the other terms and conditions applicable to the design, procurement, construction and/or installation of facilities under this GIA, all work shall comply with the following further conditions:

(i) All work performed by or on behalf of the Project Developer shall be conducted by contractors, and using equipment manufacturers or vendors, that are listed on the Transmission Owner's List of Approved Contractors;

(ii) The Transmission Owner shall have full site control of, and reasonable access to, its property at all times for purposes of tagging or operation, maintenance, repair or construction of modifications to, its existing facilities and/or for performing all tie-ins of Interconnection Facilities and Stand Alone Network Upgrades built by or for the Project Developer; and for acceptance testing of any equipment that will be owned and/or operated by the Transmission Owner;

(iii) The Transmission Owner shall have the right to have a reasonable number of appropriate representatives present for all work done on its property/facilities or regarding the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades and the right to stop, or to order corrective measures with respect to, any such work that reasonably could be expected to have an adverse effect on reliability, safety or security of persons or of property of the Transmission Owner or any portion of the Transmission System, provided that, unless circumstances do not reasonably permit such consultations, the Transmission Owner shall consult with the Project Developer and with Transmission Provider before directing that work be stopped or ordering any corrective measures;

(iv) The Project Developer and its contractors, employees and agents shall comply with the Transmission Owner's safety, security and work rules, environmental guidelines and training requirements applicable to the area(s) where construction activity is occurring and shall provide all reasonably required documentation to the Transmission Owner, provided that the Transmission Owner previously has provided its safety, security and work rules and training requirements applicable to work on its facilities to Transmission Provider and the Project Developer within 20 Business Days after a request therefor made by Project Developer;

(v) The Project Developer shall be responsible for controlling the performance of its contractors, employees and agents; and

(vi) All activities performed by or on behalf of the Project Developer pursuant to its exercise of the Option to Build shall be subject to compliance with Applicable Laws and Regulations, including those governing union staffing and bargaining unit obligations, and Applicable Standards.

11.2.3.4 Administration of Conditions:

To the extent that the Transmission Owner exercises any discretion in the application of any of the conditions stated in sections 11.2.3.2 and 11.2.3.3 of this Schedule L, it shall apply each such condition in a manner that is reasonable and not unduly discriminatory and it shall not unreasonably withhold, condition, or delay any approval or authorization that the Project Developer may require for the purpose of complying with any of those conditions.

11.2.3.5 Approved Contractors:

(a) Each Transmission Owner shall develop and shall provide to Transmission Provider a List of Approved Contractors. Each Transmission Owner shall include on its List of Approved Contractors no fewer than three contractors and no fewer than three manufacturers or vendors of major transmission-related equipment, unless a Transmission Owner demonstrates to Transmission Provider's reasonable satisfaction that it is feasible only to include a lesser number of construction contractors, or manufacturers or vendors, on its List of Approved Contractors. Transmission Provider shall publish each Transmission Owner's List of

Approved Contractors in a PJM Manual and shall make such manual available on its internet website.

(b) Upon request of a Project Developer, a Transmission Owner shall add to its List of Approved Contractors (1) any design or construction contractor regarding which the Project Developer provides such information as the Transmission Owner may reasonably require which demonstrates to the Transmission Owner's reasonable satisfaction that the candidate contractor is qualified to design, or to install and/or construct new facilities or upgrades or modifications to existing facilities on the Transmission Owner's system, or (2) any manufacturer or vendor of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) regarding which the Project Developer provides such information as the Transmission Owner may reasonably require which demonstrates to the Transmission Owner's reasonable satisfaction that the candidate entity's major transmission-related equipment is acceptable for installation and use on the Transmission Owner's system. No Transmission Owner shall unreasonably withhold, condition, or delay its acceptance of a contractor, manufacturer, or vendor proposed for addition to its List of Approved Contractors.

11.2.3.6 Construction by Multiple Project Developers:

In the event that there are multiple Project Developers that wish to exercise an Option to Build with respect to Interconnection Facilities and Stand Alone Network Upgrades of the types described in section 11.2.3.3 of this Schedule L, the Transmission Provider shall determine how to allocate the construction responsibility among them unless they reach agreement among themselves on how to proceed.

11.2.3.7 Option Procedures:

(a) Within 10 days after executing this GIA or directing that this GIA be filed with FERC unexecuted, Project Developer shall solicit bids from one or more Approved Contractors named on the Transmission Owner's List of Approved Contractors to procure equipment for, and/or to design, construct and/or install, the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that the Project Developer seeks to build under the Option to Build on terms (i) that will meet the Project Developer's proposed schedule; (ii) that, if the Project Developer seeks to have an Approved Contractor construct or install Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades, will satisfy all of the conditions on construction specified in sections 11.2.3.2 and 11.2.3.3 of this Schedule L; and (iii) that will satisfy the obligations of a Constructing Entity (other than those relating to responsibility for the costs of facilities).

(b) Any additional costs arising from the bidding process or from the final bid of the successful Approved Contractor shall be the sole responsibility of the Project Developer.

(c) Upon receipt of a qualifying bid acceptable to it, the Project Developer shall contract with the Approved Contractor that submitted the qualifying bid. Such contract shall meet the standards stated in paragraph (a) of this section.

(d) In the absence of a qualifying bid acceptable to the Project Developer in response to its solicitation, the Transmission Owner(s) shall be responsible for the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades in accordance with the Standard Option described in section 11.2.1 of this Schedule L.

11.2.3.8 Project Developer Drawings:

Project Developer shall submit to the Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Transmission Owner Interconnection Facilities and Stand that Project Developer arranges to build under this Option to Build. The Transmission Owner shall review and approve the initial drawings and engineering design of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades to be constructed under the Option to Build. The Transmission Owner shall review the drawings to assess the consistency of Project Developer’s design of the pertinent Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades with Applicable Standards and the System Impact Study(ies). Transmission Owner, with facilitation and oversight by Transmission Provider, shall provide comments on such drawings to Project Developer within 60 days after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved. All drawings provided hereunder shall be deemed to be Confidential Information.

11.2.3.9 Effect of Review:

Transmission Owner’s review of Project Developer's initial drawings of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that the Project Developer is building shall not be construed as confirming, endorsing or providing a warranty as to the fitness, safety, durability or reliability of such facilities or the design thereof. At its sole cost and expense, Project Developer shall make such changes to the design of the pertinent Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades as may reasonably be required by Transmission

Provider, in consultation with the Transmission Owner, to ensure that the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that Project Developer is building meet Applicable Standards and conform with the System Impact Study(ies).

11.3 Revisions to Schedule of Work:

The Schedule of Work shall be revised as required in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals, or otherwise by mutual agreement of the Interconnection Parties, which agreement shall not be unreasonably withheld, conditioned or delayed. The scope change process is intended to be used for changes to the Scope of Work as defined herein, and is not intended to be used to change any of the milestone set forth in the GIA.

11.4 Right to Complete Transmission Owner Interconnection Facilities and Transmission Owner Upgrades:

In the event that, at any time prior to successful Stage Two energization of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades pursuant to section 11.8 of this Schedule L, Project Developer terminates its obligations under this GIA,Appendix 2, section 16.1.2 due to a Default by Transmission Owner, the Project Developer may elect to complete the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades. Project Developer shall notify Transmission Owner and Transmission Provider in writing of its election to complete the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades within 10 days after the date of Project Developer's notice of termination pursuant to GIA, Appendix 2, section 16.1.2. In the event that Project Developer elects to complete the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades, it shall do so in accordance with the terms and conditions of the Option to Build under section 11.2.3 of this Schedule L and shall be responsible for paying all costs of completing the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades incurred after the date of its notice of election to complete the facilities. Project Developer may take possession of, and may use in completing the Transmission Owner Interconnection Facilities, any materials and supplies and equipment (other than equipment and facilities that already have been installed or constructed) acquired by Transmission Owner for construction, and included in the Costs, of the Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades, provided that Project Developer shall pay Transmission Provider, for the benefit of the Transmission Owner and upon presentation by Transmission Owner of reasonable and appropriate documentation thereof, any amounts expended by Transmission Owner for such materials, supplies and equipment that Project Developer has not already paid. Title to all Transmission Owner Interconnection Facilities and Transmission Owner Upgrades constructed by Project Developer under this section 11 shall be transferred to the Transmission Owner in accordance with GIA, Appendix 2, section 23.3.5.

11.5 Suspension of Work upon Default:

Upon the occurrence of a Default by Project Developer as defined in Appendix 2, section 16 of this GIA, the Transmission Provider or the Transmission Owner may by written notice to Project Developer suspend further work associated with the construction and installation of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades that the Transmission Owner is responsible for constructing. Such suspension shall not constitute a waiver of any termination rights under this GIA. In the event of a suspension by Transmission Provider or Transmission Owner, the Project Developer shall be responsible for the Costs incurred in connection with any suspension hereunder in accordance with Appendix 2, section 16 of this GIA.

11.6 Construction Reports:

Each of Project Developer and Transmission Owner shall issue reports to each other on a monthly basis, and at such other times as reasonably requested, regarding the status of the construction and installation of the Interconnection Facilities and Transmission Owner Upgrades. Each of Project Developer and Transmission Owner shall promptly identify, and shall notify each other of, any event that the party reasonably expects may delay completion, or may significantly increase the cost, of the Interconnection Facilities and Transmission Owner Upgrades. Should either Project Developer or Transmission Owner report such an event, Transmission Provider shall, within 15 days of such notification, convene a technical meeting with Project Developer and Transmission Owner to evaluate schedule alternatives.

11.7 Inspection and Testing of Completed Facilities

11.7.1 Coordination:

Project Developer and the Transmission Owner shall coordinate the timing and schedule of all inspection and testing of the Interconnection Facilities and Transmission Owner Upgrades.

11.7.2 Inspection and Testing:

Each of Project Developer and Transmission Owner shall cause inspection and testing of the Interconnection Facilities and Transmission Owner Upgrades that it constructs in accordance with the provisions of this section. Project Developer and Transmission Owner acknowledge and agree that inspection and testing of facilities may be undertaken as facilities are completed and need not await completion of all of the facilities that a party is building.

11.7.2.1 Of Project Developer-Built Facilities:

Upon the completion of the construction and installation, but prior to energization, of any Interconnection Facilities and Transmission Owner Upgrades constructed by the Project Developer and related portions of the

Generating Facility or Merchant Transmission Facility, the Project Developer shall have the same inspected and/or tested by an authorized electric inspection agency or qualified third party reasonably acceptable to the Transmission Owner to assess whether the facilities substantially comply with Applicable Standards. Said inspection and testing shall be held on a mutually agreed-upon date, and the Transmission Owner and Transmission Provider shall have the right to attend and observe, and to obtain the written results of, such testing.

11.7.2.2 Of Transmission Owner-Built Facilities:

Upon the completion of the construction and installation, but prior to energization, of any Interconnection Facilities and Transmission Owner Upgrades constructed by the Transmission Owner, the Transmission Owner shall have the same inspected and/or tested by qualified personnel or a qualified contractor to assess whether the facilities substantially comply with Applicable Standards. Subject to Applicable Laws and Regulations, said inspection and testing shall be held on a mutually agreed-upon date, and the Project Developer and Transmission Provider shall have the right to attend and observe, and to obtain the written results of, such testing.

11.7.3 Review of Inspection and Testing by Transmission Owner:

In the event that the written report, or the observation of either of Project Developer and Transmission Owner or Transmission Provider, of the inspection and/or testing pursuant to section 11.7.2 of this Schedule L reasonably leads the Transmission Provider or Transmission Owner to believe that the inspection and/or testing of some or all of the Interconnection Facilities and Stand Alone Network Upgrades built by the Project Developer was inadequate or otherwise deficient, the Transmission Owner may, within 20 days after its receipt of the results of inspection or testing and upon reasonable notice to the Project Developer, perform its own inspection and/or testing of such Interconnection Facilities and Stand Alone Network Upgrades to determine whether the facilities are acceptable for energization, which determination shall not be unreasonably delayed, withheld or conditioned.

11.7.4 Notification and Correction of Defects

11.7.4.1 If the Transmission Owner, based on inspection or testing pursuant to section 11.7.2 or 11.7.3 of this Schedule L, identifies any defects or failures to comply with Applicable Standards in the Interconnection Facilities and Stand Alone Network Upgrades constructed by the Project Developer, the Transmission Owner shall notify the Project Developer and Transmission Provider of any identified defects or failures within 20 days after the Transmission Owner’s receipt of the results of such inspection or testing. The Project Developer shall take appropriate actions to correct any such defects or failure at its sole cost and expense, and shall obtain the Transmission Owner's acceptance of the corrections, which acceptance shall not be unreasonably delayed, withheld or conditioned. Such acceptance does not modify and shall not limit the Project Developer's indemnification obligations set forth in section 11.2.3.2(a) of this Schedule L.

11.7.4.2 In the event that inspection and/or testing of any Transmission Owner Interconnection Facilities and Transmission Owner Upgrades built by the Transmission Owner identifies any defects or failures to comply with Applicable Standards in such facilities, Transmission Owner shall take appropriate action to correct any such defects or failures within 20 days after it learns thereof. In the event that such a defect or failure cannot reasonably be corrected within such 20-day period, Transmission Owner shall commence the necessary correction within that time and shall thereafter diligently pursue it to completion.

11.7.5 Notification of Results:

Within 10 days after satisfactory inspection and/or testing of Interconnection Facilities and Stand Alone Network Upgrades built by the Project Developer (including, if applicable, inspection and/or testing after correction of defects or failures), the Transmission Owner shall confirm in writing to the Project Developer and Transmission Provider that the successfully inspected and tested facilities are acceptable for energization.

11.8 Energization of Completed Facilities

(A) Unless otherwise provided in the Schedule of Work, energization of the Interconnection Facilities and Transmission Owner Upgrades related to interconnection of a Generation Project Developer and, when applicable as determined by Transmission Provider, of the Interconnection Facilities and Transmission Owner Upgrades related to interconnection of a Transmission Project Developer, shall occur in two stages. Stage One energization shall consist of energization of the Project Developer Interconnection Facilities and of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades and will occur prior to initial energization of the Generating Facility. Stage Two energization shall consist of (1) initial synchronization to the Transmission System of any completed generator(s) at the Generating Facility of a Generation Project Developer, or of applicable facilities, as determined by the Transmission Provider, associated with Merchant Transmission Facilities of a Transmission Project Developer, and (2) energization of the remainder of the Transmission Owner Interconnection Facilities and Transmission Owner Upgrades. Stage Two energization shall be completed prior to Initial Operation of the Generating Facility or Merchant Transmission Facility.

(B) In the case of Interconnection Facilities and Transmission Owner Upgrades related to interconnection of a Transmission Project Developer for which the Transmission

Provider determines that two-stage energization is inapplicable, energization shall occur in a single stage, consisting of energization of the Interconnection Facilities and Transmission Owner Upgrades and the Generating Facility or Merchant Transmission Facility. Such a single-stage energization shall be regarded as Stage Two energization for the purposes of the remaining provisions of this section 11.8.

11.8.1 Stage One energization of the Interconnection Facilities and Transmission Owner Upgrades may not occur prior to the satisfaction of the following additional conditions:

(a) The Project Developer shall have delivered to the Transmission Owner and Transmission Provider a writing transferring to the Transmission Owner and Transmission Provider operational control over any Transmission Owner Interconnection Facilities that Project Developer has constructed; and

(b) The Project Developer shall have provided a mark-up of construction drawings to the Transmission Owner to show the "as-built" condition of all Transmission Owner Interconnection Facilities and Stand Alone that Project Developer has constructed.

11.8.2 As soon as practicable after the satisfaction of the conditions for Stage One energization specified in sections 11.7 and 11.8.1 of this Schedule L, the Transmission Owner and the Project Developer shall coordinate and undertake the Stage One energization of facilities.

11.8.3 Stage Two energization of the Interconnection Facilities and Transmission Owner Upgrades may not occur prior to the satisfaction of the following additional conditions:

(a) The Project Developer shall have delivered to the Transmission Owner and Transmission Provider a writing transferring to the Transmission Owner and Transmission Provider operational control over any Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that Project Developer has constructed and operational control of which it has not previously transferred pursuant to section 11.8.1 of this Schedule L;

(b) The Project Developer shall have provided a mark-up of construction drawings to the Transmission Owner to show the "as-built" condition of all Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades that Project Developer has constructed and which were not included in the Stage One energization, but are included in the Stage Two energization; and

(c) Telemetering systems shall be operational and shall be providing Transmission Provider and the Transmission Owner with telemetered data as specified pursuant to section 8.5.2 of Appendix 2 to this GIA.

11.8.4 As soon as practicable after the satisfaction of the conditions for Stage Two energization specified in sections 11.7 and 11.8.3 of this Schedule L, the Transmission Owner and the Project Developer shall coordinate and undertake the Stage Two energization of facilities.

11.8.5 To the extent defects in any Interconnection Facilities and Transmission Owner Upgrades are identified during the energization process, the energization will not be deemed successful. In that event, the Constructing Entity shall take action to correct such defects in any Interconnection Facilities and Transmission Owner Upgrades that it built as promptly as practical after the defects are identified. The affected Constructing Entity shall so notify the other Construction Parties when it has corrected any such defects, and the Constructing Entities shall recommence efforts, within 10 days thereafter, to energize the appropriate Interconnection Facilities and Transmission Owner Upgrades in accordance with this section 11.8; provided that the Transmission Owner may, in the reasonable exercise of its discretion and with the approval of Transmission Provider, require that further inspection and testing be performed in accordance with section 11.7 of this Schedule L.

11.9 Transmission Owner's Acceptance of Facilities Constructed by Project Developer:

Within five days after determining that Interconnection Facilities and Transmission Owner Upgrades have been successfully energized, the Transmission Owner shall issue a written notice to the Project Developer accepting the Interconnection Facilities and Transmission Owner Upgrades built by the Project Developer that were successfully energized. Such acceptance shall not be construed as confirming, endorsing or providing a warranty by the Transmission Owner as to the design, installation, construction, fitness, safety, durability or reliability of any Interconnection Facilities and Transmission Owner Upgrades built by the Project Developer, or their compliance with Applicable Standards.

11.10 Addendum of Non-Standard Terms and Conditions for Construction Service. In the event of any conflict between a provision of Schedule F of this GIA that FERC has accepted and any provision of the standard terms and conditions set forth in this Schedule L and Appendix 2 of this GIA that relates to the same subject matter, the pertinent provision of Schedule F of this GIA shall control.

SCHEDULE L, APPENDIX 1

NEGOTIATED CONTRACT OPTION TERMS

Not Required.

ATTACHMENT B

Copy of Sheet Containing Original Signatures and Initialed Replacement Pages

IN WITNESS WHEREOF, Transmission Provider, Project Developer and Transmission Owner have caused this GIA to be executed by their respective authorized officials.

(Project Identifier #AG1-471)

Transmission Provider: **PJM Interconnection, L.L.C.**

By:	Andrew Lambert	Manager, Interconnection Planning Projects	Jan 12, 2026
	Name	Title	Date

Printed name of signer: Andrew Lambert

Project Developer: **Barrelhead Solar, LLC**

By:	Chris Norqual	Authorized Representative	Jan 7, 2026
	Name	Title	Date

Printed name of signer: Chris Norqual

Transmission Owner: **East Kentucky Power Cooperative, Inc.**

By:	Brad Young	Vice President	Jan 8, 2026
	Name	Title	Date

Printed name of signer: Brad Young

6.11 **Commercial Operation.** On or before January 15, 2029, Project Developer must demonstrate commercial operation of all generating units in order to achieve the full Maximum Facility Output set forth in section 1.0(c) of the Specifications to this GIA. Failure to achieve this Maximum Facility Output may result in a permanent reduction in Maximum Facility Output of the Generating Facility, and, if necessary, a permanent reduction of the Capacity Interconnection Rights, to the level achieved. Demonstrating commercial operation includes achieving Initial Operation in accordance with section 1.4 of Appendix 2 to this GIA and making commercial sales or use of energy, as well as, if applicable, obtaining capacity qualification in accordance with the requirements of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and fulfillment of 6.10 “Dispatchability Demonstration” milestone.

6.12 **As-Built Data.** As a condition precedent to PJM reflecting an “in-service” status for the Generating Facility or the Merchant Transmission Facilities and no later than 30 days following the demonstration of commercial operation, Project Developer must provide certified documentation demonstrating that “as-built” Generating Facility or the Merchant Transmission Facilities, and Project Developer Interconnection Facilities are in accordance with applicable PJM studies and agreements. Project Developer must also provide PJM with “as-built” electrical modeling data and confirm that previously submitted data remains valid. All modeling data must conform to the PJM Dynamic Model Development Guidelines for Interconnection Analysis in effect as of the effective date of this GIA.

Project Developer shall demonstrate the occurrence of each of the foregoing milestones to Transmission Provider’s reasonable satisfaction. Transmission Provider may reasonably extend any such milestone dates, in the event of delays that Project Developer (i) did not cause and (ii) could not have remedied through the exercise of due diligence. Project Developer shall also have a one-time option to extend its milestone (other than any milestone related to Site Control) for a total period of one year regardless of cause. This option may only be applied one time for an Interconnection Request, and may only be applied to one single milestone specified in this GIA. Other milestone dates stated in this GIA shall be deemed to be extended coextensively with Project Developer’s use of this provision. Once this extension is used, it is no longer available with regard to any other milestones or other deadlines in this GIA. If the Project Developer fails to meet any of the milestones set forth above, including any extended milestones, its Interconnection Request shall be terminated and withdrawn, subject to the provisions of Appendix 2, sections 15 and 16. Transmission Provider shall take all necessary steps to effectuate this termination, including submitting the necessary filings with FERC.

7.0 Provision of Interconnection Service. Transmission Provider and Transmission Owner agree to provide for the interconnection to the Transmission System in the PJM Region of Project Developer’s Generating Facility or Merchant Transmission Facility identified in

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ii. Facilities for which a Network Upgrade Cost Responsibility Agreement is required.

Identifier	Description	Category	Transmission Owner
(None)			

d. Additional Contingent Facilities which must be completed prior to Commercial Operation of the Generating Facility or Merchant Transmission Facility

Except as determined through an interim deliverability study for a particular Delivery Year, in order to maintain system reliability, the 54 MW Energy / 32.4 MW Capacity associated with PJM Project Identifier AG1-471 and the Generating Facility under this GIA cannot come fully into service prior to the completion of the following PJM Network Upgrade(s), baseline upgrade(s), and/or Supplemental Project upgrades:

Identifier	Description	Category
(None)		

4.0 Subject to modification pursuant to the Negotiated Contract Option and/or the Option to Build, Project Developer shall be subject to the estimated charges detailed below, which shall be billed and paid in accordance with GIA, Appendix 2, section 11 and GIA, Schedule L, section 9.0.

4.1 Transmission Owner Interconnection Facilities Charge: $718,000.00

4.2 Network Upgrades Charge: $13,187,000.00

Identifier	Cost Allocation	Transmission Owner
n9514.0	$7,050,000.00	East Kentucky Power Cooperative, Inc.
n9513.0	$63,000.00	East Kentucky Power Cooperative, Inc.
n9512.0	$63,000.00	East Kentucky Power Cooperative, Inc.
n9511.0	$554,000.00	East Kentucky Power Cooperative, Inc.

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n9510.0	$5,457,000.00	East Kentucky Power Cooperative, Inc.

4.3 Option to Build Charges $0.00

4.4 Distribution Upgrades Charge: $0.00

4.5 Other Charges: $0.00

4.6 Cost breakdown:

$	7,239,000.00	Direct Labor
$	5,274,000.00	Direct Material
$	1,252,000.00	Indirect Labor
$	140,000.00	Indirect Material

$13,905,000.00 Total

4.7 Security Amount Breakdown:

$13,905,000.00 Estimated Cost of Network Upgrades, Distribution Upgrades, Transmission Owner Interconnection Facilities, and Other Charges

plus $0.00 Option to Build Security for Transmission Owner Interconnection Facilities and Stand Alone Network Upgrades (including Cancellation Costs)

$13,905,000.00 Sum of Security required for Costs listed in GIA, Specifications sections 4.1 through 4.5

less $0 Portion of Costs already paid by Project Developer

$13,905,000.00 Net Security amount required

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3 Modification of Facilities

3.1 General:

Subject to Applicable Laws and Regulations and to any applicable requirements or conditions of the Tariff and the Operating Agreement, either Interconnected Entity may undertake modifications to its facilities ("Planned Modifications"). In the event that an Interconnected Entity plans to undertake a modification, that Interconnected Entity, in accordance with Good Utility Practice, shall provide notice to the other Interconnection Parties with sufficient information regarding such modification, including any modification to its project that causes the project's capacity, location, configuration or technology to differ from any corresponding information provided in the Interconnection Request, so that the other Interconnection Parties may evaluate the potential impact of such modification prior to commencement of the work. The Interconnected Entity may make changes to SCHEDULE A GENERATING FACILITY LOCATION/SITE PLAN and corresponding Site Control parcels provided they demonstrate to Transmission Provider that the change does not adversely impact the timing of milestones or Transmission Owner construction schedule. Project Developer shall submit to Transmission Provider an attestation in accordance with the PJM template that the modification to SCHEDULE A will have no impact on the overall timing of milestones (including backfeed date). Additionally, the attestation shall include acknowledgement from Project Developer that they waive the ability to request future milestone extensions related to permits or other land issues. In the event Transmission Provider determines the change impacts modeling assumptions, the Interconnected Entity desiring to perform such modification shall provide the relevant drawings, plans, specifications and models to the other Interconnection Parties in advance of the beginning of the work. Transmission Provider and the applicable Interconnection Entity shall enter into a Necessary Studies Agreement, a form is located in the Tariff, Part IX, pursuant to which Transmission Provider agrees to conduct the necessary studies to determine whether the Planned Modifications will have a permanent material impact on the Transmission System or would constitute a Material Modification, and to identify the additions, modifications, or replacements to the Transmission System, if any, that are necessary, in accordance with Good Utility Practice and/or to maintain compliance with Applicable Laws and Regulations or Applicable Standards, to accommodate the Planned Modifications.

The Interconnected Entity shall provide the information required by the Necessary Study Agreement and provide the required deposit. Transmission Provider, upon completion of the Necessary Studies, shall provide the Interconnected Entity (i) the type and scope of the permanent material impact, if any, the Planned Modifications will have on the Transmission System; (ii) the additions, modifications, or replacements to the Transmission System required to accommodate the Planned Modifications; and (iii) a good faith estimate of the cost of the additions, modifications, or replacements to the Transmission System required to accommodate the Planned Modifications. In the event such Planned Modification have a permanent material impact on the Transmission System or would constitute a Material Modification, Project Developer shall then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

3.2 Interconnection Request:

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ATTACHMENT C

Redlined Pages Showing Schedule of Charges and Nonconforming Provisions

SCHEDULE E

SCHEDULE OF CHARGES

The Administrative, Metering, Telemetering, and Generating Facility Operations and Maintenances ("O&M") Charges referenced below refer to charges described in Section 10.1 of the Standard Terms and Conditions for Interconnections, which are contained in Appendix 2 of this Generation Interconnection Agreement.

ADMINISTRATIVE CHARGES

The charges that EKPC would assess for Administration Charges would be its actual costs.

METERING CHARGES

The charges that EKPC would assess for Metering Charges would be its actual costs.

TELEMETERING CHARGES

The charges that EKPC would assess for Telemetering Charges would be its actual costs.

O&M CHARGES

EKPC reserves the right to charge its actual costs to the Project Developer for O&M expenses to maintain the Project Developer's Interconnection Facilities including metering equipment owned by Transmission Owner.

i. Facilities for which the Project Developer has sole cost responsibility.

Identifier	Description	Category
	One (1) 69 kV generator lead line to include, but not be limited to, installation of a 69 kV line monopole dead-end structure and foundation, a 3-pole disconnect switch mounted to the monopole, line conductor from the dead-end structure to the bus position in the switchyard, and two (2) 48-strand fiber optic cables.	Transmission Owner Interconnection Facilities
n9510.0	Install new overhead optical ground wire (OPGW) on the existing Wayne County - Massingale Road and Massingale Road - Summer Shade 69 kV line sections for a total of 44.2 miles.	Network Upgrades
n9511.0	Loop existing Upchurch Tap - Wayne County 69 kV line into new interconnection switching station.	Network Upgrades
n9512.0	Revise Relay Settings at Wayne County Sub.	Network Upgrades
n9513.0	Revise Relay Settings at Summer Shade Sub.	Network Upgrades
n9514.0	Massingale Road Substation: Construct new 69 kV switching station.	Stand-Alone Network Upgrades

ii. Facilities for which a Network Upgrade Cost Responsibility Agreement is required.

Identifier	Description	Category
(None)		

c. Any additional Transmission Owner constructing facilities with which Project Developer and Transmission Provider will also execute a Construction Service Agreement appears below

i. Facilities for which the Project Developer has sole cost responsibility.

Identifier	Description	Category	Transmission Owner
(None)			

SCHEDULE F

SCHEDULE OF NON-STANDARD TERMS & CONDITIONS

Louisville Gas & Electric as Affected System Operator:

The System Impact Studies Report for AG1-471 reflects the Affected System study results provided by the Affected System Operator. As identified in the Affected System study results, the AG1-471 project is contingent upon the Affected System upgrades identified below. These results may be subject to adjustments based on the outcome of any remaining phases of the Affected System Operator's Generator Interconnection Process.

The need for any Affected System upgrades shall not delay Initial Operation of a Project Developer's Generating Facility. Notwithstanding the start of Initial Operation, and in accordance with Good Utility Practice, the Generating Facility may be subject to limitations by PJM on its injections and/or withdrawals prior to (1) completion of any remaining studies or necessary restudies by the Affected System Operator; and (2) completion of any Affected System upgrades identified through those studies. Total injections and/or withdrawals may be limited pending coordination and completion of any necessary studies in accordance with the Affected System Operator's Tariff.

Affected System Upgrades with Cost Allocation:

Project Developer has cost responsibility and shall enter into any and all agreements required by Louisville Gas & Electric leading to the study and construction of the following required transmission facilities or upgrades on the Louisville Gas & Electric transmission system in accordance with the Affected System Operator's Tariff. The Generating Facility may also be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of these upgrades:

(Louisville Gas and Electric) Campbellsville 2 Tap - Taylor County 69 kV Line Reconductor
(Louisville Gas and Electric) Lebanon - Springfield 69 kV Line Reconductor
(Louisville Gas and Electric) Morehead W - Morehead 69 kV Line Reconductor
(Louisville Gas and Electric) Shelbyville South - Shelby Co Tap 69 kV Line MOT
(Louisville Gas and Electric) Springfield - North Springfield 69 kV Line MOT
(Louisville Gas and Electric) Brown North - Tyrone 138 kV Line Reconductor

Affected System Upgrades without Cost Allocation:

Additionally, the Generating Facility may be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of the following Affected System upgrades; however, Project Developer does not have cost responsibility for the upgrades:

(None)

Midcontinent Independent System Operator as Affected System Operator:

The System Impact Studies Report for AG1-471 reflects the Affected System study results provided by the Affected System Operator. As identified in the Affected System study results, the AG1-471 project is contingent upon the Affected System upgrades identified below. These results may be subject to adjustments based on the outcome of any remaining phases of the Affected System Operator's Generator Interconnection Process.

The need for any Affected System upgrades shall not delay Initial Operation of a Project Developer's Generating Facility. Notwithstanding the start of Initial Operation, and in accordance with Good Utility Practice, the Generating Facility may be subject to limitations by PJM on its injections and/or withdrawals prior to (1) completion of any remaining studies or necessary restudies by the Affected System Operator; and (2) completion of any Affected System upgrades identified through those studies. Total injections and/or withdrawals may be limited pending coordination and completion of any necessary studies in accordance with the Affected System Operator's Tariff.

Affected System Upgrades with Cost Allocation:

Project Developer has cost responsibility and shall enter into any and all agreements required by Midcontinent Independent System Operator leading to the study and construction of the following required transmission facilities or upgrades on the Midcontinent Independent System Operator transmission system in accordance with the Affected System Operator's Tariff. The Generating Facility may also be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of these upgrades:

(Duke Energy Indiana) Install 28.8 MVAR cap bank at Avon East sub

Affected System Upgrades without Cost Allocation:

Additionally, the Generating Facility may be subject to limitations by PJM on its total injections and/or withdrawals prior to completion of the following Affected System upgrades; however, Project Developer does not have cost responsibility for the upgrades:

(None)

Report on

PJM-TC1
Affected System ReStudy

Revision R1 February 20, 2026

Submitted to
Louisville Gas & Electric Kentucky Utilities

LG&E KU
PPL companies

anedenconsulting.com

Confidential

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APPENDIX A: Steady State Generation Dispatch Scenarios
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APPENDIX C: Steady State Results

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
2/20/2026	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) to perform an Affected System ReStudy (ReStudy) for Generation Interconnection (GI) requests in the PJM Interconnection (PJM) PJM-TC1 queue to evaluate the impact of their interconnection on the LG&E/KU transmission system. LG&E/KU previously studied this cluster in the Affected System Study completed in August 2025, after which several of projects in the cluster withdrew with seven (7) remaining. Two of the seven projects, AG1-070 and AG1-071, refused the ReStudy so only five (5) projects were included in this ReStudy (henceforth referred to as PJM-TC1). The five projects evaluated in this ReStudy are shown Table ES-1.

The PJM-TC1 project details are shown in Table ES-1 below.

Table ES-1: PJM-TC1 Affected System ReStudy Requests

PJM GI	Max Capability (MW)	State	Transmission Owner	Requested In-Service Date	Generation Type	Point of Interconnection	Included in Steady State	Status
AF1-233	188.5	KY	EKPC	5/31/2022	Solar	Flemingsburg – Spurlock 138kV	X	Active
AG1-070	45	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-071	55	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-320	82	KY	EKPC	10/1/2023	Solar	Glendale-Stephensburg 69 kV	X	Active
AG1-341	106	KY	EKPC	6/15/2023	Solar; Storage	Summer Shade 161 kV	X	Active
AG1-354	150	KY	EKPC	12/31/2023	Solar	Summershade-Green County 161 kV	X	Active
AG1-471	54 (reduced from 60)	KY	EKPC	10/2/2023	Solar	Up Church-Wayne County 69 kV	X	Active

Aneden performed steady state analysis using a set of Pre-Project and Post-Project study models. The Pre-Project models include the relevant LG&E/KU GI projects as well as previously studied PJM projects and all relevant GI upgrades from each set of projects. The Post-Project models are with the additional PJM-TC1 projects in place.

The steady state analysis was performed using a set of six (6) scenarios, studying the Off-Peak, Summer, and Winter seasons in two different case years (2029 and 2034).

For the steady state analysis, the LG&E/KU Affected System Study Criteria and Methodology document[1] was used to determine if the PJM-TC1 projects had an impact on the LG&E/KU system. The impacts presented are based on the criteria described in Sections 4 and 5 of the LG&E/KU Affected System Study Criteria and Methodology document. The applicable North American Electric Reliability Corporation (NERC) Transmission Planning Standard (TPL-001-5) was also applied to assess system performance under studied P0 Conditions and P1, P2, P3, P4, P6, and P7 Planning Events[2].

Results

The steady state analysis results showed that the addition of the PJM-TC1 projects did not cause any new voltage impacts within the LG&E/KU transmission system that met the criteria. However, there was one (1) thermal constraints found that required mitigation. LG&E/KU reviewed the impacts and determined the

[1] LG&E/KU Affected System Study Criteria and Methodology Version 0.0 July 6, 2021
[2] Planning Events P5 were not included as part of the analysis within this Study.

necessary system network upgrades. The project information and planning level cost estimate are summarized in Table ES-2. The PJM-TC1 project level cost allocations are provided in Section 4.1.

Table ES-2: PJM-TC1 System Network Upgrade Summary

Monitored Facility	Need Date	Upgrade Project	Planning Level Cost Estimate	Estimated Lead Time (months)
4SPENCER RD 138.00 TO 2021-018POI 138.00 1	5/30/2034	Increase the MOT of the 8.25 mile of 556.5 MCM 26X7 ACSR in the Spencer Rd-GI-2021-018 POI 138kV line to 176°F.	$6,187,500	30

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) to perform an Affected System Study (Study) for Generation Interconnection (GI) requests in the PJM Interconnection (PJM) PJM-TC1 queue to evaluate the impact of their interconnection on the LG&E/KU transmission system. LG&E/KU previously studied this cluster in the Affected System Study completed in August 2025, after which several of projects in the cluster withdrew with seven (7) remaining. Two of the seven projects, AG1-070 and AG1-071, refused the ReStudy so only five (5) projects were included in this ReStudy (henceforth referred to as PJM-TC1).

1.1 Scope

The Study methodology, assumptions, and results of the analyses are presented in the following main sections:

- Project Description
- Steady State Analysis
  - Methodology & Criteria
  - Model Development
  - Analysis Results
- Conclusion

Aneden performed steady state analysis using a set of Pre-Project and Post-Project study models. The Pre-Project models include the relevant LG&E/KU GI requests as well as previously studied PJM requests and all relevant GI upgrades from each set of projects. The Post-Project models are with the remaining PJM-TC1 projects in place. All analyses were performed using the PTI PSS/E version 34 software and custom tools provided by LG&E/KU.

The steady state analysis was performed using a set of six (6) Pre and Post-Project scenarios as shown in Table 1-1.

Table 1-1: PJM-TC1 Steady State Study Models

Case Year/Season	Pre-Project	Post-Project
2029 Summer Peak	2029S 2025 TEP r20241004 pre-PJM	2029S 2025 TEP r20241004 post-PJM
2029 Off-Peak	2029OP 2025 TEP r20241004 pre-PJM	2029OP 2025 TEP r20241004 post-PJM
2029 Winter Peak	2029W 2025 TEP r20241004 pre-PJM	2029W 2025 TEP r20241004 post-PJM
2034 Summer Peak	2034S 2025 TEP r20241004 pre-PJM	2034S 2025 TEP r20241004 post-PJM
2034 Off-Peak	2034OP 2025 TEP r20241004 pre-PJM	2034OP 2025 TEP r20241004 post-PJM
2034 Winter Peak	2034W 2025 TEP r20241004 pre-PJM	2034W 2025 TEP r20241004 post-PJM

1.2 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project Description

PJM-TC1 restudy consists of five PJM requests in the PJM-TC1 queue that are in close proximity to the LG&E/KU system. This Study evaluated the impacts of the PJM-TC1 projects on the LG&E/KU transmission system as a combined cluster. Note that five of the projects previously studied, AE2-275, AF1-116, AG1-067, AG1-070, and AG1-071 were withdrawn or refused restudy. The individual project details are shown in Table 2-1 below.

Table 2-1: PJM-TC1 Affected System ReStudy Requests

PJM GI	Max Capability (MW)	State	Transmission Owner	Requested In-Service Date	Generation Type	Point of Interconnection	Included in Steady State	Status
AF1-233	188.5	KY	EKPC	5/31/2022	Solar	Flemingsburg – Spurlock 138kV	X	Active
AG1-070	45	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-071	55	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-320	82	KY	EKPC	10/1/2023	Solar	Glendale-Stephensburg 69 kV	X	Active
AG1-341	106	KY	EKPC	6/15/2023	Solar; Storage	Summer Shade 161 kV	X	Active
AG1-354	150	KY	EKPC	12/31/2023	Solar	Summershade-Green County 161 kV	X	Active
AG1-471	54 (reduced from 60)	KY	EKPC	10/2/2023	Solar	Up Church-Wayne County 69 kV	X	Active

LG&E/KU was notified by PJM as a Potentially Affected System for these PJM-TC1 projects due to constraints found during the PJM study process.

As a result, this Affected System Study was initiated to further investigate the potential impacts of the cluster on the LG&E/KU transmission system.

3.0 Steady State Analysis

The steady state modeling was completed using PTI PSS/E software version 34.7.0. Aneden used an LG&E/KU provided custom Screening Tool to simulate, process, and evaluate the system contingencies as well as generation dispatch scenarios for the Planning Event P3 analysis. The analysis was performed in accordance with criteria and methodology specified in the LG&E/KU Affected System Study Criteria and Methodology (Methodology)[3].

3.1 Methodology

A steady state analysis was performed to identify any impacts on the LG&E/KU transmission system caused by the five PJM-TC1 Restudy projects. The results of the analysis were evaluated by comparing the thermal loading and voltage magnitude of the monitored LG&E/KU lines, ties, and buses under numerous dispatch and contingency scenarios.

Aneden identified the branch loadings and voltage magnitudes in the Pre-Project study models and the Post-Project study models to determine if there were new impacts created by the addition of the PJM-TC1 Restudy projects.

The applicable NERC Transmission Planning Standard (TPL-001-5) was applied to assess system performance under studied P0 Conditions and P1, P2, P3, P4, P6, and P7 Planning Events[4], as defined in Table 3-1.

Table 3-1: Planning Condition and Event Definitions

Planning Event	Event Definition
P0	System Normal Contingencies, No Contingencies
P1	Single Contingency - Generator, Transmission Circuit, Transformer, Shunt Device or Single Pole of DC Line
P2	Single Contingency – Line Section Loss w/o a fault, Buss Section Fault, Internal Breaker Fault
P3	Multiple Contingency - loss of generator unit followed by a loss of Generator, Transmission Circuit, Transformer, Shunt Device or Single Pole of DC Line
P4	Multiple Contingency caused by stuck breaker attempting to clear a fault on Generator, Transmission Circuit, Transformer, Shunt Device or Bus Section
P6	Multiple Contingency - loss of Transmission Circuit, Transformer, Shunt Device or Single Pole of DC Line followed by a loss of Transmission Circuit, Transformer, Shunt Device or Single Pole of DC Line
P7	Multiple Contingency - loss of any two adjacent (vertically or horizontally) circuits on common structure or loss of a bipolar DC line

The planning events were simulated using the LG&E/KU provided Screening Tool.

3.2 Reliability and Impact Criteria

LG&E/KU's Affected System Study Criteria and Methodology was applied to identify reliability criteria exceptions caused by the interconnection of the PJM-TC1 Restudy projects.

[3] LG&E/KU Affected System Study Criteria and Methodology Version 0.0 July 6, 2021
[4] Planning Events P5 were not included as part of the analysis within this Study.

Equipment loadings were monitored to record any criteria exceptions based on their 100% static applicable rating. The criteria require all transmission elements to either operate within their ratings, or if violated, the impact between the Pre-Project and Post-Project models must be within allowable ranges shown in Table 3-2 and Table 3-3 below. Therefore, all criteria exceptions were recorded for the identification of the transmission system deficiencies.

Thermal impacts were defined as pre-contingency overloads greater than 100% of the Rate A or post-contingency overloads greater than 100% of the Rate B and at least one of the following conditions met:

1. The Distribution Factor (DF) is equal to or greater than 3% on the overloaded facility
2. Neighboring Project results in flow increase of at least 5 MVA on the overloaded facility
3. Neighboring Project results in flow increase of at least 5% of the applicable rating on the overloaded facility

The DF was calculated for the cumulative PJM-TC1 restudy cluster. Table 3-2 summarizes the thermal impact criteria.

Table 3-2: Thermal Impact Criteria

System Condition	Maximum Allowable Facility Loading	Additional Overloaded Facility Criteria
Pre-Contingency (N-0)	<=100% of Normal Rating (Rate A)	DF: ≥ 3% or Flow Increase: ≥5 MVA or Flow Increase: ≥5%
Post-Contingency (N-1)	<=100% of Long-Term Emergency (LTE) Rating (Rate B)	

Voltage impacts were defined as any new voltage criteria exceptions based on the specific voltage range identified for each bus and voltage criteria exceptions worsened by greater than 1% impact on the monitored bus voltage in the Post-Project model as compared to the Pre-Project model. Table 3-3 summarizes the voltage impact criteria.

Table 3-3: Voltage Impact Criteria

System	Voltage	Pre-Contingency Voltage (p.u.)		Post-Contingency Voltage (p.u.)		Delta Voltage
		Low	High	Low	High	
LG&E/KU Area 363	69 kV - 499 kV	0.94	1.05*	0.90	1.05*	1.00%
LG&E/KU Area 363	500 kV	0.94	1.10*	0.90	1.10*	1.00%

*High voltage violations do not constitute a cost allocation per Section 5 of the LG&E Affected System Criteria

3.3 Study System

The simulated planning events consisted of events in the LG&E/KU system and surrounding areas. Contingency files were provided by LG&E/KU for P1, P2, P3, P4, P6, and P7 Planning Events. The LG&E/KU (Area 363) region was monitored for loading and voltage impacts as shown in Table 3-4 below.

Table 3-4: Areas and Voltages Monitored

Planning Event	Area and Voltage Range
P2, P4, P6, & P7	Area 363, 138 - 500 kV
P1 & P3	Area 363, 69 - 500 kV

3.4 Dispatch Scenarios

LG&E/KU provided several dispatch scenarios to be evaluated. These dispatches were applied in combination with each P1 Planning Event during the P3 Planning Event analysis. Appendix A shows the generation dispatch scenarios.

3.5 Steady State Modeling Details

This section describes the steady state study models developed for the analysis, as listed in Table 3-5.

Table 3-5: PJM-TC1 Steady State Study Models

Case Year/Season	Pre-Project	Post-Project
2029 Summer Peak	2029S 2025 TEP r20241004 pre-PJM	2029S 2025 TEP r20241004 post-PJM
2029 Off-Peak	2029OP 2025 TEP r20241004 pre-PJM	2029OP 2025 TEP r20241004 post-PJM
2029 Winter Peak	2029W 2025 TEP r20241004 pre-PJM	2029W 2025 TEP r20241004 post-PJM
2034 Summer Peak	2034S 2025 TEP r20241004 pre-PJM	2034S 2025 TEP r20241004 post-PJM
2034 Off-Peak	2034OP 2025 TEP r20241004 pre-PJM	2034OP 2025 TEP r20241004 post-PJM
2034 Winter Peak	2034W 2025 TEP r20241004 pre-PJM	2034W 2025 TEP r20241004 post-PJM

3.5.1 LG&E/KU Pre-Project Model Development

The following starting LG&E/KU 2025 Transmission Expansion Plan (TEP) seasonal steady state cases were provided by LG&E/KU for this Study:

- 2029 Summer Peak
- 2029 Off-Peak
- 2029 Winter Peak
- 2034 Summer Peak
- 2034 Off-Peak
- 2034 Winter Peak

The steady state Pre-Project models were created by taking the starting cases and including LG&E/KU GI projects that had at least signed a Facility Study Agreement prior to the original execution of the Affected System Study Agreement and all relevant GI upgrades as provided by LG&E/KU. Table 3-6 shows the LG&E/KU GI projects included in the six (6) starting cases. If any of the LG&E/KU projects were already modeled and dispatched, they were not altered. If any LG&E/KU projects had been withdrawn by the study start, they were turned off and any associated upgrades were removed.

Table 3-6: LG&E/KU GIs Included in Steady State Study Models

GI	County	Description	Point of Interconnection	Capacity (MW)
GI-2017-002	Lyon	Solar	Livingston Co to North Princeton 161kV	86
GI-2019-025	Mercer	Solar	Bardstown to Brown CT 138kV	98
GI-2021-007	McCracken	Solar	Grahamville 161kV	120
GI-2021-008	Clark (IN)	Solar+BESS	Trimble to Speed 345kV	500
GI-2021-009	Hardin	Solar+BESS	Hardin Co to Davies Co 345kV	200
GI-2021-010	Marion	Solar	Lebanon 138kV	120
GI-2021-013	Hardin	BESS	Hardin Co 69kV	120
GI-2021-017	Mason	Solar+BESS	Wedonia to Kenton 138kV	100
GI-2021-018	Bath	Solar+BESS	Spencer Road to Farmers Tap 138 kV	110
GI-2021-019	Boyle	Solar	KY ST Hospital 69 kV	100
GI-2021-020	McCracken	Solar+BESS	Grahamville 161 kV	120

The Pre-Project models also included the addition of several previously studied PJM projects as shown in Table 3-7 along with any relevant PJM upgrades. The modeling data was provided by PJM. If any of the listed PJM projects were already modeled in the later year cases, the topology was extracted and included in the near term cases and all models were redispatched according to LG&E/KU instructions. If any PJM projects had been withdrawn by the start of the study, they were turned off and any associated upgrades were removed.

Table 3-7: PJM GIs Included in Steady State Study Models

GI	County	Description	Point of Interconnection	Capacity (MW)
AB1-087	Sullivan (IN)	Natural Gas	Sullivan 345kV #1	550
AB1-088	Sullivan (IN)	Natural Gas	Sullivan 345kV #2	550
AC1-074	Harrison (KY)	Solar	Jacksonville-Renaker 138kV I	80
AC2-157	Sullivan (IN)	Solar	Sullivan 345 kV	200
AE1-143	Marion (KY)	Solar	Marion County 161 kV	96
AF1-050	Green (KY)	Solar	Summer Shade - Green County 161 kV	60
AF1-083	Barren (KY)	Solar	Green County-Saloma 161 kV	55
AF2-111	Mason (KY)	Solar	North Clark-Spurlock 345 kV	250

Per LG&E/KU, all newly added LG&E/KU GI projects (not already dispatched) and all of the specified PJM GI projects in Table 3-7 were dispatched according to each project's Generation Interconnection Capacity (GIC) and fuel type as shown in Table 3-8.

Table 3-8: Steady State Resource Dispatch Percentages

Resource Type	Summer Peak Dispatch	Off-Peak/Light Load Dispatch	Winter Peak Dispatch
Wind	20% Pmax	20% Pmax	20% Pmax
Solar	80% Pmax	100% GIC + Aux	0% (Aux offline)
BESS	100% GIC + Aux	100% GIC + Aux	100% GIC + Aux
Hybrid (Solar/BESS)	Solar @ 80% Pmax, BESS @ 20% ((GIC + Aux) - Solar Pgen) or Max Capability	Solar @ 100% GIC + Solar Aux or Max Capability BESS @ ((GIC + BESS Aux) - Solar Pgen) or Max Capability	Solar @ 0%, BESS @ 100% GIC + Aux or Max Capability
Natural Gas	100% GIC + Aux	100% GIC + Aux	100% GIC + Aux

The LG&E/KU projects were dispatched by reducing the LG&E/KU generator units in merit order while maintaining the spinning reserve per LG&E/KU's Transmission Planning Guidelines[5]. The PJM projects were dispatched by sinking the generation to the provided PJM areas as shown in Table 3-9 and adjusting the area interchanges.

Table 3-9: PJM Areas for Dispatching

PJM Areas		
201	225	233
202	226	234
205	227	235
206	228	236
209	229	237
212	230	238
215	231	320
222	232	345

3.5.2 Post-Project Model Development

The PJM-TC1 Post-Project models were created by taking the Pre-Project models and including the five (5) PJM-TC1 projects as shown in Table 2-1 using files provided by PJM and the above PJM dispatch methodology.

3.6 Steady State Analysis Results

The results were evaluated by comparing the loading and voltage between the Pre-Project and Post-Project study models. Only impacts that meet the cost allocation criteria requirements as described in Section 5 of the LG&E/KU Affected System Study Criteria and Methodology document and summarized in Section 3.2 are shown below. There were a number of non-converged contingencies that did not solve in either the Pre- or Post-Project models. These were considered pre-existing issues and were not resolved within this affected system study.

3.6.1. Steady State P0 Results

There were no P0 thermal or voltage impacts within the LG&E/KU transmission system that met the impact criteria.

[5] LG&E/KU Transmission System Planning Guidelines October 31, 2023

3.6.2. Steady State P1 Results

There were no P1 thermal or voltage impacts within the LG&E/KU transmission system that met the impact criteria and were assigned mitigation. The impacts that were seen that did not require mitigation for the PJM-TC1 cluster are shown in Appendix C.

3.6.3. Steady State P2 Results

Table 3-10 shows the worst P2 thermal loading impact for each monitored facility in each year and season. The contingency definitions are provided in Appendix B. There were no P2 voltage impacts within the LG&E/KU system that met the impact criteria.

Table 3-10: PJM-TC1 Worst P2 Thermal Violations Per Case

Year	Season	Monitored Facility	Contingency	Rating (MVA)	Pre-Project MVA	Post-Project MVA	MVA Increase	Pre-Project %Loading	Post-Project %Loading	%Loading Increase
2034	S	4SPENCER RD 138.00 TO 2021-018POI 138.00 1	EKPC P2-128	121	127.05	133.81	6.76	105.00%	110.59%	5.59%

3.6.4. Steady State P3 Results

Table 3-11 shows the worst P3 thermal loading impact for each monitored facility in each year and season. The contingency definitions are provided in Appendix B. There were no P3 voltage impacts within the LG&E/KU system that met the impact criteria. The thermal impacts that were seen that did not require mitigation for the PJM-TC1 cluster are shown in Appendix C.

Table 3-11: PJM-TC1 Worst P3 Thermal Violations Per Case

Year	Season	Monitored Facility	Dispatch	Contingency	Rating (MVA)	Pre-Project MVA	Post-Project MVA	MVA Increase	Pre-Project %Loading	Post-Project %Loading	%Loading Increase
2034	S	4SPENCER RD 138.00 TO 2021-018POI 138.00 1	br3_merit_miso	SINGLE OPN LIN 324467-324528(1)	121	117.57	126.09	8.52	97.17%	104.21%	7.04%

3.6.5. Steady State P4 Results

Table 3-12 shows the worst P4 thermal loading impact for each monitored facility in each year and season. The contingency definitions are provided in Appendix B. There were no P4 voltage impacts within the LG&E/KU system that met the impact criteria.

Table 3-12: PJM-TC1 Worst P4 Thermal Violations Per Case

Year	Season	Monitored Facility	Contingency	Rating (MVA)	Pre-Project MVA	Post-Project MVA	MVA Increase	Pre-Project %Loading	Post-Project %Loading	%Loading Increase
2034	S	4SPENCER RD 138.00 TO 2021-018POI 138.00 1	EKPC P4-68	121	127.05	133.81	6.76	105.00%	110.59%	5.59%

3.6.6. Steady State P6 Results

Table 3-13 shows the worst P6 thermal loading impact for each monitored facility in each year and season. The contingency definitions are provided in Appendix B. There were no P6 voltage impacts within the LG&E/KU system that met the impact criteria.

Table 3-13: PJM-TC1 Worst P6 Thermal Violations Per Case

Year	Season	Monitored Facility	Contingency	Rating (MVA)	Pre-Project MVA	Post-Project MVA	MVA Increase	Pre-Project %Loading	Post-Project %Loading	%Loading Increase
2034	S	4SPENCER RD 138.00 TO 2021-018POI 138.00 1	P6 1591	121	116.27	123.99	7.72	96.09%	102.47%	6.38%

3.6.7. Steady State P7 Results

There were no P7 thermal or voltage impacts within the LG&E/KU transmission system that met the impact criteria.

3.7 Steady State Analysis System Network Upgrades

LG&E/KU provided system network upgrade information and modeling files to resolve the steady state impacts found in this affected system study. The project information and cost estimates are summarized in Table 3-14. Due to the expedited nature of this study, planning level cost estimates were provided by LG&E/KU.

Table 3-14: PJM-TC1 Steady State System Network Upgrade Summary

Monitored Facility	Need Date	Upgrade Project	Planning Level Cost Estimate	Estimated Lead Time (months)
4SPENCER RD 138.00 TO 2021-018POI 138.00 1	5/30/2034	Increase the MOT of the 8.25 mile of 556.5 MCM 26X7 ACSR in the Spencer Rd-GI-2021-018 POI 138kV line to 176°F.	$6,187,500	30

3.7.1. Steady State Analysis Project Descriptions

Spencer Road – GI-2021-018 POI 69 kV Line MOT

- Planning Level Cost Estimate: $6,187,500
- Need Date: 5/30/2034
- Estimated Construction Timeline: 30 months
- Project Description: Increase the MOT of the 8.25 mile of 556.5 MCM 26X7 ACSR in the Spencer Rd-GI-2021-018 POI 138kV line to 176°F.

3.7.2. Steady State Upgrade Cost Allocation

Each LG&E/KU System Network Upgrade was cost allocated across the PJM-TC1 generators. If the individual generators within the PJM-TC1 cluster increased the flow on the overloaded facility it was allocated a percentage of the responsibility for the corresponding system network upgrade based on the individual flow increase. If the generator did not have an adverse impact on a facility it was not allocated cost for the corresponding upgrade.

The cost allocation was completed using a Cost Allocation Tool (CAT) developed for LG&E/KU by Aneden. Each PJM-TC1 generator was added separately to the Pre-Project case and dispatched to the PJM system to assess the increase in loading on the impacted facility under the highest loaded scenario (using that specific year, season, and contingency).

Table 3-15 shows the allocation of costs for the identified system network upgrade described in Section 3.7.1. Note that the request MW shown represents the seasonal dispatch (not the project capacity) and the distribution factor shown was calculated using the MW impact and is shown for reference only.

Table 3-15: Spencer Rd – GEN-2021-018 POI 69 kV Line MOT Cost Allocation

Request	Request MW (Seasonal Dispatch)	DF on Constrained Facility	MW Impact on Facility	MW Impact for Allocation	Allocation %	Allocated Cost
AF1-233	180	5.93%	10.68	10.68	100.00%	$6,187,500.00
AG1-320	65.6	-0.76%	-0.50	0	0.00%	$0.00
AG1-341	93.3	-0.60%	-0.56	0	0.00%	$0.00
AG1-354	120	-0.68%	-0.82	0	0.00%	$0.00
AG1-471	43.2	-0.74%	-0.32	0	0.00%	$0.00
		Total Impact	8.48	10.68	100%	$6,187,500.00

4.0 Conclusion

As Affected System ReStudy was performed for five (5) PJM projects shown in Table 4-1 below, chosen based on the proximity of the generation to the LG&E/KU system (PJM-TC1).

Table 4-1: PJM-TC1 Affected System Study Requests

PJM GI	Max Capability (MW)	State	Transmission Owner	Requested In-Service Date	Generation Type	Point of Interconnection	Included in Steady State	Status
AF1-233	188.5	KY	EKPC	5/31/2022	Solar	Flemingsburg – Spurlock 138kV	X	Active
AG1-070	45	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-071	55	KY	EKPC	6/1/2024	Solar	Bon Ayr 69 kV		Refused Restudy
AG1-320	82	KY	EKPC	10/1/2023	Solar	Glendale-Stephensburg 69 kV	X	Active
AG1-341	106	KY	EKPC	6/15/2023	Solar; Storage	Summer Shade 161 kV	X	Active
AG1-354	150	KY	EKPC	12/31/2023	Solar	Summershade-Green County 161 kV	X	Active
AG1-471	60	KY	EKPC	10/2/2023	Solar	Up Church-Wayne County 69 kV	X	Active

The results of the steady state analysis identified a thermal impact that required mitigation. A cost allocation was performed on the resulting system network upgrades to determine the responsibility on each PJM-TC1 project. No voltage impacts were found due to the PJM-TC1 generators.

4.1 PJM-TC1 Project Assigned Upgrade Costs

Table 4-2 through Table 4-6 show the assigned upgrade costs allocated to each of the PJM-TC1 projects.

Table 4-2: AF1-233 Allocated Cost Summary

Request	Upgrade Project	Allocated Cost
AF1-233	Spencer Road – GI-2021-018 POI 69 kV Line MOT	$6,187,500.00
	Total Cost	$6,187,500.00

Table 4-3: AG1-320 Allocated Cost Summary

Request	Upgrade Project	Allocated Cost
AG1-320	N/A	$0.00
	Total Cost	$0.00

Table 4-4: AG1-341 Allocated Cost Summary

Request	Upgrade Project	Allocated Cost
AG1-341	N/A	$0.00
	Total Cost	$0.00

Table 4-5: AG1-354 Allocated Cost Summary

Request	Upgrade Project	Allocated Cost
AG1-354	N/A	$0.00
	Total Cost	$0.00

Table 4-6: AG1-471 Allocated Cost Summary

Request	Upgrade Project	Allocated Cost
AG1-471	N/A	$0.00
	Total Cost	$0.00

5.0 LG&E/KU Contact Information

For any questions regarding modeling, planning criteria, or analysis, please contact:

Benjamin Garffie
Principal Engineer
859-367-5621
Benjamin.Garffie@lge-ku.com

For any questions regarding the LG&E/KU OATT, or to initiate a facilities construction agreement, please contact:

Ashley Vinson
Manager, Transmission Policy and Tariff
502-627-3278
Ashley.Vinson@lge-ku.com

Report Number: R121-25

MISO Affected System Study for PJM TC1 Cluster

Prepared for

MISO

Submitted by:
Yaming Zhu, Consulting Director, Principal Consultant
William Wang, Lead Consultant
Qiyan Li, Senior Consultant
Don Dharmapala, Consultant
Ketian Ye, Consultant
Zhengrong Chen, Consultant
Juhee Yeo, Consultant
Ehsan Fouladi, Consultant

9/12/2025

Siemens PTI Project Number: 62OT-002742

Siemens Industry, Inc.
Siemens Power Technologies International
10900 Wayzata Boulevard
Minnetonka, Minnesota 55305 USA
Tel: +1 (317) 903-9803
www.siemens.com/power-technologies

SIEMENS

Revision History

Date	Rev.	Description
08/15/2025	A	Initial draft
09/12/2025	B	Update short circuit screen results

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Executive Summary

This report presents the results of an Affected System Impact Study (AFSIS) on MISO transmission system performed for 64 projects in the PJM generator interconnection queue TC1 Cluster. The AFSIS results are summarized below.

1.1 Project List

The PJM TC1 Cluster has 64 generation projects with a combined energy of 12272.29 MW. The PJM TC1 Cluster generating facilities (Study Projects) are listed in Table ES-1.

Table ES-1: Study Projects in PJM TC1 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO	SH Discharge (MW)	SH Charge (MW)	SPK (MW)
AE1-114	IL	Ogle	ComEd	Maryland-Lancaster 138 kV	Wind	150	150	150	150	23.4
AE1-172	IL	Livingston	ComEd	Loretto-Wilton Center	Wind	255	255	255	255	39.78
AE2-173	IL	McLean	ComEd	McLean 345 kV	Storage	50	250	50	-50	50
AE2-223	IL	McLean	ComEd	McLean 345 kV	Wind	150	150	150	150	23.4
AE2-261	IL	Christian	ComEd	Kincaid-Pana 345 kV	Solar	299	299	0	0	159.75 142
AE2-308	KY	Madison	EKPC	Three Forks-Dale 138 kV	Solar	100	100	0	0	100
AE2-321	IL	McHenry	ComEd	Belvidere-Marengo 138 kV	Solar	100	100	0	0	100
AE2-325	MI	Van Buren	AEP	Valley 138 kV	Storage	52.2	152.2	52.2	-52.2	52.2
AE2-341	IL	Kendall	ComEd	Sandwich-Plano 138 kV	Solar	150	150	0	0	150
AF1-030	IL	Kendall	ComEd	Sandwich-Plano 138 kV	Solar	100	250	0	0	100
AF1-088	IN	Sullivan	AEP	Sullivan 345 kV	MHVDC	1000	1000	±1000	±1000	±1000
AF1-161	MI	Van Buren	AEP	Valley 138 kV	Storage	50	50	50	-50	50
AF1-176	MI	St. Joseph	AEP	Corey 138 kV	Solar; Storage	300	300	0 121.58	0 -121.58	178.42 121.58
AF1-204	IN	Vermillion	AEP	Eugene 345 kV	Wind	255	255	255	255	39.78
AF1-233	KY	Fleming	EKPC	Flemingsburg – Spurlock 138kV	Solar	188.5	188.5	0	0	188.5
AF1-280	IL	Lee	ComEd	Nelson-Lee County	Solar	200	200	0	0	200
AF1-296	IL	Whiteside	ComEd	Garden Plain 138 kV	Wind	190.89	190.89	190.89	190.89	29.78
AF2-008	IN	Sullivan	AEP	Sullivan 345 kV	MHVDC	1000	2000	±1000	±1000	±1000

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO	SH Discharge (MW)	SH Charge (MW)	SPK (MW)
AF2-041	IL	Lee	ComEd	Nelson-Electric Junction 345 kV	Solar	300	300	0	0	159.048 155.35
AF2-068	IN	Blackford	AEP	Jay 138 kV	Solar	150	150	0	0	150
AF2-069	IL	Bureau	ComEd	Crescent Ridge 138 kV	Wind	8.4	87.8	8.4	8.4	1.31
AF2-095	IL	Kankakee	ComEd	Davis Creek 138 kV	Solar	144	144	0	0	144
AF2-111	KY	Mason	EKPC	North Clark-Spurlock 345 kV	Solar	250	250	0	0	250
AF2-126	OH	Wood	ATSI	Weston 69 kV II	Solar	12	62	0	0	12
AF2-142	IL	Lasalle	ComEd	Nevada 345 kV	Solar	150	150	0	0	150
AF2-143	IL	Lasalle	ComEd	Powerton-Nevada 345 kV	Solar	150	150	0	0	150
AF2-173	IN	Delaware	AEP	Desoto 345 kV	Solar	140	140	0	0	140
AF2-177	IN	Blackford	AEP	Sorenson-DeSoto #2 345 kV	Wind	200	200	200	200	31.2
AF2-182	IL	Lee	ComEd	Nelson-Lee County 345 kV II	Solar	300	500	0	0	300
AF2-199	IL	Lee	ComEd	Nelson-Electric Junction 345 kV	Solar	100	400	0	0	100
AF2-200	IL	Lee	ComEd	Nelson-Electric Junction 345 kV	Solar	200	600	0	0	200
AF2-225	IL	McLean	ComEd	McLean 345 kV	Solar	150	150	0	0	150
AF2-226	IL	Lasalle	ComEd	Katydid Road 345 kV	Storage	50	50	50	-50	50
AF2-307	KY	Bath	EKPC	Hope-Belvins Valley Tap 69 kV	Solar	64.2	64.2	0	0	64.2
AF2-319	IL	Lasalle	ComEd	Katydid Road 345 kV	Storage	50	50	50	-50	50
AF2-335	IN	Delaware	AEP	Delaware-Royerton 138 kV	Solar	100	100	0	0	100
AF2-349	IL	McHenry	ComEd	SILVER LAKE- CHERRY VALLEY 345 KV	Solar	300	300	0	0	300
AF2-350	IL	Kankakee	ComEd	Kensington 138 kV	Solar	100	100	0	0	100
AF2-388	IN	Blackford	AEP	Keystone-Desoto 345 kV	Wind	200	200	200	200	31.2
AF2-392	IL	Lee	ComEd	Nelson-Dixon 138 kV	Wind	199	199	199	199	31.04
AF2-396	MI	Cass	AEP	Stinger 138 kV	Solar; Storage	200	200	0 80	0 -80	200 0
AF2-407	IN	Madison	AEP	Fall Creek 345 kV	Storage	300	300	300	-300	300
AF2-441	IL	Cook	ComEd	Burnham 138kV	Storage	200	200	200	-200	200
AG1-118	IL	DeKalb	ComEd	Sugar Grove-Waterman 138kV	Solar	300	300	0	0	300
AG1-127	IL	DeKalb	ComEd	Crego Rd 138 kV	Solar	95.1	190	0	0	95.1

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO	SH Discharge (MW)	SH Charge (MW)	SPK (MW)
AG1-226	IN	Fountain	AEP	Eugene-Dequine 345 kV	Solar	450	450	0	0	450
AG1-236	IL	Logan	ComEd	Lanesville-Brokaw 345 kV	Wind	180	380	180	180	28.08
AG1-297	IN	Shelby	AEP	Hanna-Tanners Creek 345 kV	Storage	300	300	300	-300	300
AG1-320	KY	Hardin	EKPC	Glendale-Stephensburg 69 kV	Solar	82	82	0	0	82
AG1-341	KY	Metcalfe	EKPC	Summer Shade 161 kV	Solar; Storage	106	106	106	0	106
AG1-354	KY	Green	EKPC	Summershade-Green County 161 kV	Solar	150	150	0	0	150
AG1-367	IN	Delaware	AEP	DeSoto 345 kV	Solar	100	100	0	0	100
AG1-374	IL	McLean	ComEd	Blue Mound 345 kV	Solar	300	300	0	0	300
AG1-375	IN	Blackford	AEP	Sorenson-Desoto 345 kV	Solar	100	100	0	0	100
AG1-410	OH	Van Wert	AEP	Maddox Creek-RP Mone 345 kV	Solar	300	300	0	0	300
AG1-411	OH	Van Wert	AEP	Maddox Creek-RP Mone 345 kV	Storage	100	400	100	-100	100
AG1-433	IN	Blackford	AEP	Keystone-DeSoto 345 kV	Wind	100	300	100	100	15.6
AG1-436	IN	LaPorte	AEP	Olive-University Park 345 kV	Solar	125	250	0	0	125
AG1-447	IN	LaPorte	AEP	Olive-University Park 345 kV	Storage	55	305	55	-55	55
AG1-460	IL	Christian	ComEd	Kincaid-Pana 345 kV	Storage	30	329	30	-30	30
AG1-462	IL	Whiteside	ComEd	Cordova 345 kV	Solar	255	255	0	0	255
AG1-471	KY	Wayne	EKPC	Up Church-Wayne County 69 kV	Solar	54	54	0	0	54
AG1-526	KY	Garrard	EKPC	West Garrard 345 kV	Solar	222	222	0	0	222
AG1-553	IL	Rock Island	ComEd	Cordova 345 kV	Solar	260	260	0	0	260

1.2 Study Summary

MISO AFSIS study for PJM TC1 Cluster was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI.

MISO AFSIS steady state study includes MISO Base analysis and NIPSCO LPC analysis.

Due to many severe thermal and voltage constraints identified in MISO system, the MISO AFSIS steady state study has two study stages. The Stage-1 steady state study is to identify Base Case Network Upgrades for mitigating initial severe thermal and voltage constraints. With the Base Case Network Upgrades included, the Stage-2 steady state study is to identify additional Network Upgrades.

It should be noted that, a restudy might be needed if there are significant changes in the study assumptions, including but not limited to, changes of the prior queued Network Upgrade included in the model, withdrawals of higher queued projects from MISO or PJM interconnection queue, and/or changes to the TC1 study projects listed in Table ES-1.

1.2.1 Stage-1 MISO AFSIS Steady State Study

The Stage-1 MISO Base steady state analysis detailed results are in Appendix B. The Stage-1 worst thermal constraints are in Table 2-1, and the Stage-1 worst voltage constraints are in Appendix B.7.

The Stage-1 NIPSCO Local Planning Criteria (LPC) analysis detailed results are in Appendix C. Additional thermal constraints with maximum screened loadings identified in NIPSCO LPC analysis are in Table 3-1.

1.2.2 Base Case Network Upgrades

Based on the Stage-1 MISO AFSIS steady state analysis, Base Case Network Upgrades were identified and justified to mitigate several thermal and voltage constraints identified in the Stage-1 study. The Base Case Network Upgrades are listed below.

Table ES-2: PJM Backbone Network Upgrades

Project Name	Description
ComEd_s3011	Replace 345 kV open air straight bus with GIS in a breaker and half configuration (34 Circuit Breakers) at Goodings Grove with 80kA capability.
ComEd_b3811_Haumesser-W.Dekalb	Rebuild 138 kV from Haumesser Rd to H-452 Tap
B3775 Green Acre - Olive + St John	University Park-Olive-StJohn line Reconfiguration
AEP Jefferson-Clifty AEPSERG13	Add a second Jefferson 765/345kV XFMR connect to a parallel Jefferson - Clifty 345kV line

Table ES-3: PJM System Impact Study Network Upgrades

Facility	Area	MISO TO	Proposed Reinforcement by MISO TO
18MOROCCO (256583) [345 KV] to 02ALLEN (238530) [345 KV] ckt 1	METC/ATSI	METC	Remove sag. Ratings will be 1861/2124. Cost: $625,000. Restrictions at PJM Allen Junction needs to be removed. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.

Facility	Area	MISO TO	Proposed Reinforcement by MISO TO
05EUGENE (243221) [345 KV] to 08CAYSUB (249504) [345 KV] ckt 1	AEP/DEI	DEI	Currently working on new 4000A conductor with a rating of 2430 MV, the parallel line is not needed with the new conductor is approved. The cost to rebuild with the new conductor is $12M. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.
19MON12 (264612) [345 KV] to 02LALLENDORF (241901) [345 KV] ckt 1	ITCT/ATSI	ITCT	Reconductor ITCT section of Lallendorf-Monroe line. Post upgrade ratings will be 1677/2124. Cost: $43,500,000. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.

Table ES-4: MISO LRTP Projects

Project Name	Description
LRTP-16: Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.
LRTP-33: Greentown - Sorenson - Lulu	Install single circuit 765kV transmission line from the existing Greentown Substation to the existing Sorenson Substation, to the existing Lulu Substation.
LRTP-35: Southwest Indiana-Kentucky	Install double circuit 345kV transmission line from the existing Petersburg Substation to the new Pike County Substation. Install single circuit 345kV transmission line from the new Pike County Substation to the existing Duff Substation, to the existing Culley Substation, to the existing Reid EHV Substation.
LRTP-36: Southeast Indiana	Install single circuit 345kV transmission line from the new Madison County Substation to the existing Greensboro Substation. Install single circuit 138kV transmission line from the existing Decatur County Substation to the existing Greensburg Substation. Install double circuit 138kV transmission line from the existing Batesville Substation to the existing Hubbell Substation, to the existing Greendale Substation, to the existing Miami Fort Substation.
LRTP-37: Maywood - Belleau - MRPD - Sioux - Bugle	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Belleau Substation, to the new MRPD Substation, to the existing Sioux Substation, from the new MRPD Substation to the existing Bugle Substation.
LRTP-42: Burr Oak - Schahfer	Install single circuit 345kV transmission line from the existing Burr Oak Substation to the existing Schahfer Substation.

1.2.3 Stage-2 MISO AFSIS Steady State Study

Stage-2 MISO AFSIS steady-state analysis was performed on the benchmark and Stage-2 study cases with Base Case Network Upgrades included. Additional MISO affected system thermal and voltage Network Upgrades were identified for Study Projects in PJM TC1 cluster.

Table ES-5: Thermal Network Upgrades Identified in Stage-2 MISO Base Steady State Analysis

Constraint	Owner	Mitigation	Cost ($)	Construction time
Cayuga - Nucor 345 kV	DEI	MTEP Proj ID 50718: Rebuild with 954 ZTACSR @ 200C from Cayuga Gen Yard to Nucor. Upgrade terminal equipment accordingly.	$0	In-service dates of the different plans range from 2032-2035.
Reynold 765/345 kV xfmr	NIPSCO	2nd 765/345kV Transformer. MISO MTEP LRTP-40 Project.	$0	6/1/2034
Moro - Laclede NTP 138 kV	AMIL	MTEP project 50119, line rebuild. Assigned to DPP-2019 Central	$0	6/30/2028

Table ES-6: Voltage Network Upgrades Identified in Stage-2 MISO Base Steady State Analysis

Constraints	Network Upgrades	Owner	Cost ($)	Construction time
Low voltages in area of Gallagher 230 kV	Install 144 MVAR cap bank at Gallagher sub.	DEI	$3,000,000	3-4 yrs
Low voltage in areas of Shoals 138 kV	Install 28.8 MVAR cap bank at Shoals sub	DEI	$3,000,000	3-4 yrs
Low voltages in area of Avon East 138 kV	Install 28.8 MVAR cap bank at Avon East sub	DEI	$3,000,000	3-4 yrs

Stage-2 NIPSCO LPC contingency analysis was performed on the benchmark and Stage-2 study cases with Base Case Network Upgrades included. Additional NIPSCO LPC thermal Network Upgrades were identified for Study Projects in PJM TC1 cluster.

Table ES-7: Thermal Network Upgrades Identified in Stage-2 NIPSCO LPC Analysis

Constraint	Owner	Mitigation	Cost ($)	Construction time
Wvrich - Rochester TP 69 kV	DEI NIPSCO	DEI: Rebuild 1 mile of 69kV with 477ACSR/VR2 @ 100/120C the ratings assume that NIPSCO terminal upgrades would not limit our T-Line rating. $1.5M NIPSCO: Rebuild line, NIPSCO owns 0.037 miles of 0.9 mile line. NIPSCO portion included in Argos to Rochester tap mitigation/cost.	$1,500,000	TBD
Argos - Plymouth 69 kV	NIPSCO	Rebuild line, approx 10 miles	$12,654,948	2-3 yrs
Argos - Rochester TP 69 kV	NIPSCO	Rebuild line, approx 3.2 miles	$4,049,583	2-3 yrs

1.2.4 MISO AFSIS Transient Stability Study

Transient stability analysis was performed to identify any transient stability violations caused by the PJM projects in TC1 Cluster. Base Case Network Upgrades developed in from the Stage-1 MISO AFSIS steady state results were not included in the stability models.

Based on the MISO 2026 summer peak, summer shoulder discharging, and summer shoulder charging scenarios with either IR or WR transient stability analyses, no transient stability constraints were identified for the Study Projects in PJM TC1 Cluster; no MISO AFSIS stability NUs are required for the PJM TC1 projects.

1.2.5 Short Circuit Screening Analysis

Short circuit screening analysis was conducted by comparing three phase fault currents in the benchmark and study cases for the Study Projects in TC1 Cluster. Several AMIL buses were flagged for some PJM TC1 projects. Ameren confirmed that the related breakers can handle the 5% fault current increase. Therefore, mitigation or further study is not required.

1.2.6 Contingent Facilities

Contingent Network Upgrades were identified for the PJM projects in TC1 Cluster. Details are in Section 9.

It should be noted that a restudy may be required if significant changes to the study assumptions occur, including but not limited to, interconnection request withdrawals and/or changes to higher-queued Network Upgrades included in the Base Case, and changes to the Contingent Network Upgrade.

For the study projects that are required to mitigate thermal violations, the projects should not be allowed to come into service before the required Network Upgrades are in service, unless a MISO restudy removes the mitigation requirement from the project, or an interim limit is provided to the project through MISO Annual ERIS process.

For projects that are required to mitigate voltage violations, the projects should not be allowed to come into service before the required Network Upgrades are in service, unless a MISO restudy removes the mitigation requirement from the project, or an interim limit is provided to the project through MISO Annual ERIS process.

1.3 Total MISO AFSIS Network Upgrades for all Projects

The total cost of MISO AFSIS Network Upgrades (NU) required for each generation project is listed in Table ES-8. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies.

Table ES-8: Total Cost of MISO AFSIS Network Upgrades for PJM Generation Projects in TC1 Cluster

Project Num	Network Upgrades ($)				Total Network Upgrade Cost ($)
	MISO Thermal & Voltage	NIPSCO LPC	Transient Stability	Short Circuit	
AE1-114	$20,346	$61,847	$0	$0	$82,193
AE1-172	$26,006	$110,511	$0	$0	$136,517
AE2-173	$52,682	$102,038	$0	$0	$154,719
AE2-223	$26,006	$47,754	$0	$0	$73,760

Project Num	Network Upgrades ($)				Total Network Upgrade Cost ($)
	MISO Thermal & Voltage	NIPSCO LPC	Transient Stability	Short Circuit	
AE2-261	$389,117	$344,549	$0	$0	$733,666
AE2-308	$0	$0	$0	$0	$0
AE2-321	$78,688	$289,618	$0	$0	$368,306
AE2-325	$20,346	$229,309	$0	$0	$249,655
AE2-341	$113,720	$453,895	$0	$0	$567,614
AF1-030	$73,028	$302,596	$0	$0	$375,624
AF1-088	$1,945,685	$1,130,667	$0	$0	$3,076,352
AF2-008	$1,945,685	$1,130,667	$0	$0	$3,076,352
AF1-161	$20,346	$219,644	$0	$0	$239,991
AF1-176	$122,745	$1,373,557	$0	$0	$1,496,302
AF1-204	$66,698	$3,244	$0	$0	$69,943
AF1-233	$0	$0	$0	$0	$0
AF1-280	$166,401	$515,109	$0	$0	$681,511
AF1-296	$26,006	$69,161	$0	$0	$95,168
AF2-041	$245,758	$816,661	$0	$0	$1,062,419
AF2-068	$8,357	$0	$0	$0	$8,357
AF2-069	$0	$3,175	$0	$0	$3,175
AF2-095	$99,034	$498,921	$0	$0	$597,955
AF2-111	$0	$0	$0	$0	$0
AF2-126	$0	$2,025	$0	$0	$2,025
AF2-142	$119,380	$469,866	$0	$0	$589,247
AF2-143	$125,709	$449,616	$0	$0	$575,325
AF2-173	$8,357	$0	$0	$0	$8,357
AF2-177	$0	$0	$0	$0	$0
AF2-182	$245,758	$772,664	$0	$0	$1,018,422
AF2-199	$78,688	$272,220	$0	$0	$350,908
AF2-200	$166,401	$544,440	$0	$0	$710,842
AF2-225	$158,045	$306,113	$0	$0	$464,158
AF2-226	$46,352	$158,310	$0	$0	$204,662
AF2-307	$0	$0	$0	$0	$0
AF2-319	$46,352	$158,310	$0	$0	$204,662

Project Num	Network Upgrades ($)				Total Network Upgrade Cost ($)
	MISO Thermal & Voltage	NIPSCO LPC	Transient Stability	Short Circuit	
AF2-335	$8,357	$0	$0	$0	$8,357
AF2-349	$245,758	$848,605	$0	$0	$1,094,362
AF2-350	$73,028	$346,473	$0	$0	$419,501
AF2-388	$19,677	$0	$0	$0	$19,677
AF2-392	$26,006	$79,421	$0	$0	$105,428
AF2-396	$81,384	$892,078	$0	$0	$973,463
AF2-407	$0	$0	$0	$0	$0
AF2-441	$146,055	$764,869	$0	$0	$910,924
AG1-118	$239,429	$872,350	$0	$0	$1,111,779
AG1-127	$73,028	$273,822	$0	$0	$346,850
AG1-226	$564,833	$659,174	$0	$0	$1,224,007
AG1-236	$46,352	$39,579	$0	$0	$85,931
AG1-297	$0	$0	$0	$0	$0
AG1-320	$5,660	$0	$0	$0	$5,660
AG1-341	$16,981	$0	$0	$0	$16,981
AG1-354	$16,981	$0	$0	$0	$16,981
AG1-367	$16,713	$0	$0	$0	$16,713
AG1-374	$330,106	$565,094	$0	$0	$895,200
AG1-375	$14,686	$0	$0	$0	$14,686
AG1-410	$23,042	$0	$0	$0	$23,042
AG1-411	$0	$0	$0	$0	$0
AG1-433	$0	$0	$0	$0	$0
AG1-436	$81,384	$570,859	$0	$0	$652,243
AG1-447	$40,692	$251,178	$0	$0	$291,870
AG1-460	$37,996	$34,570	$0	$0	$72,566
AG1-462	$219,083	$579,305	$0	$0	$798,388
AG1-471	$5,660	$0	$0	$0	$5,660
AG1-526	$0	$0	$0	$0	$0
AG1-553	$225,412	$590,664	$0	$0	$816,076
Total ($)	**$9,000,000**	**$18,204,531**	**$0**	**$0**	**$27,204,531**

1.4 Per Project Summary

This section provides estimated cost of MISO AFSIS Network Upgrades on a per project basis for the PJM projects in TC1 Cluster.

The following projects in PJM TC1 Cluster do not have MISO AFSIS Network Upgrade cost allocated to the projects:

- AE2-308, AF1-233, AF2-111, AF2-177, AF2-307, AF2-407, AG1-297, AG1-411, AG1-433, AG1-526.

MISO AFSIS Network Upgrade costs are allocated to the below projects. No injection is allowed for the projects until all the allocated Network Upgrade(s) are in service, except for a revised report provided by MISO removing the requirements, or an interim limit provided for the projects through MISO Annual ERIS or Quarterly Operating Limit studies.

1.4.1 AE1-114 Summary

Network Upgrade	Owner	Cost	AE1-114	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$5,222	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$42,527	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$14,098	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	MISO Voltage
Total Cost Per Project			**$82,193**	

1.4.2 AE1-172 Summary

Network Upgrade	Owner	Cost	AE1-172	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$9,327	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$76,004	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$25,180	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$136,517**	

1.4.3 AE2-173 Summary

Network Upgrade	Owner	Cost	AE2-173	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$8,686	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$69,900	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$23,451	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$18,987	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$154,719**	

1.4.4 AE2-223 Summary

Network Upgrade	Owner	Cost	AE2-223	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$4,065	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$32,713	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$10,975	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$73,760**	

1.4.5 AE2-261 Summary

Network Upgrade	Owner	Cost	AE2-261	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$25,339	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$250,802	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$68,408	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$125,348	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$139,241	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$124,528	MISO Voltage
Total Cost Per Project			**$733,666**	

1.4.6 AE2-321 Summary

Network Upgrade	Owner	Cost	AE2-321	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$24,435	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$199,216	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$65,968	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$28,302	MISO Voltage
Total Cost Per Project			**$368,306**	

1.4.7 AE2-325 Summary

Network Upgrade	Owner	Cost	AE2-325	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$19,243	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$158,114	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$51,951	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	MISO Voltage
Total Cost Per Project			**$249,655**	

1.4.8 AE2-341 Summary

Network Upgrade	Owner	Cost	AE2-341	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$38,135	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$312,804	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$102,955	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$41,783	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$37,975	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$33,962	MISO Voltage
Total Cost Per Project			**$567,614**	

1.4.9 AF1-030 Summary

Network Upgrade	Owner	Cost	AF1-030	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$25,424	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$208,536	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$68,637	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$375,624**	

1.4.10 AF1-088 Summary

Network Upgrade	Owner	Cost	AF1-088	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$94,633	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$780,553	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$255,481	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$614,206	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$655,063	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$676,415	MISO Voltage
Total Cost Per Project			**$3,076,352**	

1.4.11 AF2-008 Summary

Network Upgrade	Owner	Cost	AF2-008	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$94,633	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$780,553	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$255,481	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$614,206	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$655,063	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$676,415	MISO Voltage
Total Cost Per Project			**$3,076,352**	

1.4.12 AF1-161 Summary

Network Upgrade	Owner	Cost	AF1-161	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$18,432	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$151,451	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$49,762	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	MISO Voltage
Total Cost Per Project			**$239,991**	

1.4.13 AF1-176 Summary

Network Upgrade	Owner	Cost	AF1-176	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$115,254	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$947,149	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$311,154	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$50,139	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$44,304	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$28,302	MISO Voltage
Total Cost Per Project			**$1,496,302**	

1.4.14 AF1-204 Summary

Network Upgrade	Owner	Cost	AF1-204	NUs Type
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$3,244	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$18,987	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$69,943**	

1.4.15 AF1-280 Summary

Network Upgrade	Owner	Cost	AF1-280	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$43,503	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$354,162	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$117,445	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$58,496	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$56,962	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$50,943	MISO Voltage
Total Cost Per Project			**$681,511**	

1.4.16 AF1-296 Summary

Network Upgrade	Owner	Cost	AF1-296	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$5,847	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$47,531	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$15,784	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$95,168**	

1.4.17 AF2-041 Summary

Network Upgrade	Owner	Cost	AF2-041	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$68,644	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$562,697	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$185,319	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$83,565	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$88,608	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$73,585	MISO Voltage
Total Cost Per Project			**$1,062,419**	

1.4.18 AF2-068 Summary

Network Upgrade	Owner	Cost	AF2-068	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Total Cost Per Project			**$8,357**	

1.4.19 AF2-069 Summary

Network Upgrade	Owner	Cost	AF2-069	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$268	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$2,182	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$724	NIPSCO LPC
Total Cost Per Project			**$3,175**	

1.4.20 AF2-095 Summary

Network Upgrade	Owner	Cost	AF2-095	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$41,898	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$343,909	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$113,113	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$33,426	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$31,646	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$33,962	MISO Voltage
Total Cost Per Project			**$597,955**	

1.4.21 AF2-126 Summary

Network Upgrade	Owner	Cost	AF2-126	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$169	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$1,398	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$458	NIPSCO LPC
Total Cost Per Project			**$2,025**	

1.4.22 AF2-142 Summary

Network Upgrade	Owner	Cost	AF2-142	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$39,619	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$323,289	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$106,959	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$41,783	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$37,975	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$39,623	MISO Voltage
Total Cost Per Project			**$589,247**	

1.4.23 AF2-143 Summary

Network Upgrade	Owner	Cost	AF2-143	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$37,924	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$309,309	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$102,383	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$41,783	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$44,304	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$39,623	MISO Voltage
Total Cost Per Project			**$575,325**	

1.4.24 AF2-173 Summary

Network Upgrade	Owner	Cost	AF2-173	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Total Cost Per Project			**$8,357**	

1.4.25 AF2-182 Summary

Network Upgrade	Owner	Cost	AF2-182	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$65,254	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$531,242	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$176,168	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$83,565	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$88,608	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$73,585	MISO Voltage
Total Cost Per Project			**$1,018,422**	

1.4.26 AF2-199 Summary

Network Upgrade	Owner	Cost	AF2-199	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$22,881	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$187,566	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$61,773	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$28,302	MISO Voltage
Total Cost Per Project			**$350,908**	

1.4.27 AF2-200 Summary

Network Upgrade	Owner	Cost	AF2-200	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$45,763	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$375,132	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$123,546	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$58,496	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$56,962	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$50,943	MISO Voltage
Total Cost Per Project			**$710,842**	

1.4.28 AF2-225 Summary

Network Upgrade	Owner	Cost	AF2-225	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$26,059	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$209,701	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$70,353	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$50,139	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$56,962	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$50,943	MISO Voltage
Total Cost Per Project			**$464,158**	

1.4.29 AF2-226 Summary

Network Upgrade	Owner	Cost	AF2-226	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$13,347	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$108,928	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$36,034	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$12,658	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$204,662**	

1.4.30 AF2-319 Summary

Network Upgrade	Owner	Cost	AF2-319	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$13,347	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$108,928	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$36,034	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$12,658	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$204,662**	

1.4.31 AF2-335 Summary

Network Upgrade	Owner	Cost	AF2-335	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Total Cost Per Project			**$8,357**	

1.4.32 AF2-349 Summary

Network Upgrade	Owner	Cost	AF2-349	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$71,610	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$583,668	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$193,327	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$83,565	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$88,608	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$73,585	MISO Voltage
Total Cost Per Project			**$1,094,362**	

1.4.33 AF2-350 Summary

Network Upgrade	Owner	Cost	AF2-350	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$29,096	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$238,826	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$78,551	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$419,501**	

1.4.34 AF2-388 Summary

Network Upgrade	Owner	Cost	AF2-388	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$19,677**	

1.4.35 AF2-392 Summary

Network Upgrade	Owner	Cost	AF2-392	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$6,708	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$54,604	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$18,109	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$105,428**	

1.4.36 AF2-396 Summary

Network Upgrade	Owner	Cost	AF2-396	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$74,859	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$615,123	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$202,097	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$33,426	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$973,463**	

1.4.37 AF2-441 Summary

Network Upgrade	Owner	Cost	AF2-441	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$64,407	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$526,582	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$173,880	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$50,139	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$50,633	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$45,283	MISO Voltage
Total Cost Per Project			**$910,924**	

1.4.38 AG1-118 Summary

Network Upgrade	Owner	Cost	AG1-118	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$73,305	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$601,143	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$197,903	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$83,565	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$82,278	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$73,585	MISO Voltage
Total Cost Per Project			$1,111,779	

1.4.39 AG1-127 Summary

Network Upgrade	Owner	Cost	AG1-127	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$23,103	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$188,346	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$62,373	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$25,070	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$346,850**	

1.4.40 AG1-226 Summary

Network Upgrade	Owner	Cost	AG1-226	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$27,966	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$555,707	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$75,500	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$183,844	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$177,215	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$203,774	MISO Voltage
Total Cost Per Project			**$1,224,007**	

1.4.41 AG1-236 Summary

Network Upgrade	Owner	Cost	AG1-236	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$3,094	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$28,133	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$8,352	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$12,658	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$85,931**	

1.4.42 AG1-320 Summary

Network Upgrade	Owner	Cost	AG1-320	NUs Type
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	MISO Voltage
Total Cost Per Project			**$5,660**	

1.4.43 AG1-341 Summary

Network Upgrade	Owner	Cost	AG1-341	NUs Type
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$16,981**	

1.4.44 AG1-354 Summary

Network Upgrade	Owner	Cost	AG1-354	NUs Type
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$16,981**	

1.4.45 AG1-367 Summary

Network Upgrade	Owner	Cost	AG1-367	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Total Cost Per Project			**$16,713**	

1.4.46 AG1-374 Summary

Network Upgrade	Owner	Cost	AG1-374	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$47,881	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$387,947	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$129,266	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$108,635	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$113,924	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$107,547	MISO Voltage
Total Cost Per Project			**$895,200**	

1.4.47 AG1-375 Summary

Network Upgrade	Owner	Cost	AG1-375	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Total Cost Per Project			**$14,686**	

1.4.48 AG1-410 Summary

Network Upgrade	Owner	Cost	AG1-410	NUs Type
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	MISO Voltage
Total Cost Per Project			**$23,042**	

1.4.49 AG1-436 Summary

Network Upgrade	Owner	Cost	AG1-436	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$48,022	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$393,189	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$129,647	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$33,426	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$25,316	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$22,642	MISO Voltage
Total Cost Per Project			**$652,243**	

1.4.50 AG1-447 Summary

Network Upgrade	Owner	Cost	AG1-447	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$21,130	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$173,003	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$57,045	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$16,713	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$12,658	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$11,321	MISO Voltage
Total Cost Per Project			**$291,870**	

1.4.51 AG1-460 Summary

Network Upgrade	Owner	Cost	AG1-460	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$2,542	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$25,164	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$6,864	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$12,658	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$16,981	MISO Voltage
Total Cost Per Project			**$72,566**	

1.4.52 AG1-462 Summary

Network Upgrade	Owner	Cost	AG1-462	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$48,983	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$398,082	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$132,240	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$75,209	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$75,949	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$67,925	MISO Voltage
Total Cost Per Project			**$798,388**	

1.4.53 AG1-471 Summary

Network Upgrade	Owner	Cost	AG1-471	NUs Type
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	MISO Voltage
Total Cost Per Project			**$5,660**	

1.4.54 AG1-553 Summary

Network Upgrade	Owner	Cost	AG1-553	NUs Type
Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$49,943	NIPSCO LPC
Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$405,888	NIPSCO LPC
Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$134,833	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$75,209	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$82,278	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$67,925	MISO Voltage
Total Cost Per Project			**$816,076**	

Section
1

Model Development and Study Criteria

1.1 Model Development

Models used in this TC1 AFSIS study were developed from MISO DPP 2021 Central Phase 2 final study models, which are listed below:

- 2026 summer peak study model:

  DPP21-Phase2-2026SUM-Dischrg-Final-12182024.sav

- 2026 summer shoulder discharging study model:

  DPP21-Phase2-2026SSH-Dischrg-Final-12182024.sav

1.1.1 Benchmark Cases

The summer peak and summer shoulder benchmark cases for the TC1 Cluster AFSIS study were created from corresponding summer peak and summer shoulder study models in DPP 2021 Central Phase 3 cycle as follows:

- Removed recently retired MISO generation in MISO North. These recently retired MISO generation are listed in Appendix A.1. Power mismatch was balanced by scaling generation in the MISO North (Table A-13).
- Removed recently withdrawn generation projects in MISO North and CIPCO. These MISO North / CIPCO recently withdrawn projects are listed in Table A-2. Power mismatch was balanced by scaling generation in the MISO North (Table A-13).
- Removed recently withdrawn generation project MPC04300 in MPC (Table A-3). Power mismatch was balanced by scaling generation in the MISO North (Table A-13).
- Added and dispatched AECI prior queued generation projects GIA-116 and GIA-117 (Table A-4). Power mismatch was balanced by scaling generation in the AECI.
- Removed recently withdrawn generation projects LGE-GIS-2019-004 and LGE-GIS-2019-008 in LG&E. Added and dispatched LG&E prior queued generation project LGE-GIS-2021-007. These LG&E withdrawn and prior queued generation projects are listed in Table A-5. Power mismatch was balanced by scaling generation in the LG&E.
- Removed PJM recently withdrawn generation projects. These PJM recently withdrawn prior queued projects are listed in Table A-6.
- Removed generation projects in PJM AE1 Cluster with simplified modeling. Added and dispatched generation projects in PJM AE1 Cluster with detailed modeling. These PJM projects in AE1 cluster are listed in Table A-7.

- Removed generation projects in PJM AE2 Cluster with simplified modeling. Added and dispatched generation projects in PJM AE2 Cluster with detailed modeling. These PJM projects in AE2 cluster are listed in Table A-8.
- Removed generation projects in PJM AF1 Cluster with simplified modeling. Added and dispatched generation projects in PJM AF1 Cluster with detailed modeling. These PJM projects in AF1 cluster are listed in Table A-9.
- Removed generation projects in PJM AF2 Cluster with simplified modeling. Added and dispatched generation projects in PJM AF2 Cluster with detailed modeling. These PJM projects in AF2 cluster are listed in Table A-10.
- Removed generation projects in PJM AG1 Cluster with simplified modeling. Added and dispatched generation projects in PJM AG1 Cluster with detailed modeling. These PJM projects in AG1 cluster are listed in Table A-11.
- Added the Study Projects in PJM TC1 Cluster with offline status. The Study Projects are listed in Table ES-1.
- The PJM generation output was sunk to the PJM market (Table A-12), where PJM generation was scaled uniformly.

1.1.2 Study Cases

Summer peak (SPK) study case was created by dispatching the Study Projects in PJM TC1 Cluster at the specified summer peak level from the summer peak benchmark case.

Summer shoulder (SH) discharging study case was created by dispatching the Study Projects in PJM TC1 Cluster at the specified summer shoulder discharging level from the summer shoulder benchmark case.

Summer shoulder (SH) charging study case was created by dispatching the Study Projects in PJM TC1 Cluster at the specified summer shoulder charging level from the summer shoulder benchmark case.

AF1-088 is a 1000 MW merchant HVDC (MHVDC) project with both Injection Right (IR) and Withdrawal Right (WR) of 1000 MW at its POI of Sullivan 345 kV in AEP. AF2-008 is also a 1000 MW MHVDC project with IR and WR of 1000 MW at the same POI of AF1-088. Both AF1-088 and AF2-008 projects were modeled as one MHVDC project with 2000 MW injection (IR) and 2000 MW withdrawal (WR) in the summer peak, summer shoulder discharging, and summer shoulder charging scenarios.

The PJM market (Table A-12) was used for power balance, where PJM generation was scaled uniformly.

Due to low voltages in areas around Marysville 765 kV, Sorenson 765 kV, and Kammer 765 kV, line reactors in several 765 kV lines were turned off in all the study cases. These 765 kV lines are: Marysville – AG1-125 POI (242928 – 962760), Marysville – AF2-137 POI (242928 – 958430), Marysville – MALIS (242928 – 242926), Sorenson – AF2-137 POI (246999 – 958430), Kammer – AB2-067 (242925 – 270162).

Additional fictitious SVCs in PJM system were also added in the study cases. These fictitious SVCs are listed in Table 1-1.

Table 1-1: Fictitious SVCs in PJM System Added in Study Cases

Bus Number	Names	Area Number	Area Name	SPK Study IR	SPK Study WR	SH Discharge Study IR	SH Discharge Study WR	SH Charge Study IR	SH Charge Study WR
200009	JUNI 500	229	PL	500 M	100.0	None	None	None	None
243210	05SULLIVAN 765	205	AEP	1700.0	1000.0	800.0	750.0	800.0	800.0
314907	8DOOMS 500	345	DVP	1250.0	800.0	None	None	None	None
242925	05KAMMER 765	205	AEP	3000.0	2450.0	1500.0	1100.0	1200.0	800.0
242928	05MARYSV 765	205	AEP	1950.0	1300.0	None	None	None	None
242924	05HANG R 765	205	AEP	2700.0	1600.0	800.0	350.0	600.0	200.0

Note: Unit of fictitious SVC size is MVar

Both study and benchmark power flow cases were solved with transformer tap adjustment enabled, area interchange disabled, phase shifter adjustment enabled and switched shunt adjustment enabled.

1.2 Contingency Criteria

The following contingencies were considered in the steady-state analysis:

- NERC Category P0 (system intact - no contingencies)
- NERC Category P1 contingencies
  - Single element outages, at buses with a nominal voltage of 60 kV and above.
  - Multiple-element NERC Category P1 contingencies.
  - NERC Category P2, P4, P5, P7 contingencies.

The detailed list of contingency files is in Appendix A.10

For all contingency and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

1.3 Monitored Elements

The MISO AFSIS study area is defined in Table 1-2. Facilities in the study area were monitored for system intact and contingency conditions. Under NERC category P0 conditions (system intact), branches were monitored for loading above the normal (PSS®E rate A) rating, and bus voltages were monitored based on normal voltage limits associated with each bus in power flow case. Under NERC category P1-P7 conditions, branches were monitored for loading as shown in the column labeled "Post-Disturbance Thermal Limits", and bus voltages were monitored based on emergency voltage limits associated with each bus in power flow case.

Table 1-2: MISO AFSIS Monitored Elements

Owner / Area	Thermal Limits [1]	
	Pre-Disturbance	Post-Disturbance
HE	100% of Rate A	100% of Rate B
DEI	100% of Rate A	100% of Rate B
SIGE	100% of Rate A	100% of Rate B
IPL	100% of Rate A	100% of Rate B
NIPS	100% of Rate A	100% of Rate B
METC	100% of Rate A	100% of Rate B
ITCT	100% of Rate A	100% of Rate B
WPSC	100% of Rate A	100% of Rate B
LBWL	100% of Rate A	100% of Rate B
BREC	100% of Rate A	100% of Rate B
HMPL	100% of Rate A	100% of Rate B
CWLD	100% of Rate A	100% of Rate B
AMMO	100% of Rate A	100% of Rate B
AMIL	100% of Rate A	100% of Rate B
CWLP	100% of Rate A	100% of Rate B
SIPC	100% of Rate A	100% of Rate B
GLH	100% of Rate A	100% of Rate B

Notes
1: PSS®E Rate A, Rate B

1.4 MISO Steady State Performance Criteria

A branch is considered as a thermal injection constraint if the branch is loaded above its applicable normal or emergency rating for the post-change case, and any of the following conditions are met:

1) the generator (NR/ER) has a larger than 20% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, or
2) the megawatt impact due to the generator is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility, or
3) the overloaded facility or the overload-causing contingency is at generator's outlet, or
4) for any other constrained facility, where none of the study generators meet one of the above criteria in 1), 2), or 3), however, the cumulative megawatt impact of the group of study generators (NR/ER) is greater than 20% of the applicable rating, then only those study generators whose individual MW impact is greater than 5% of the

applicable rating and has DF greater than 5% (OTDF or PTDF) will be responsible for mitigating the cumulative MW impact constraint.

A bus is considered a voltage constraint if both of the following conditions are met. All voltage constraints must be resolved before a project can receive interconnection service.

1) the bus voltage is outside of applicable normal or emergency limits for the post-change case, and
2) the change in bus voltage is greater than 0.01 per unit.

All Study Projects must mitigate thermal injection constraints and voltage constraints in order to obtain unconditional Interconnection Service.

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Section
2

Stage-1 MISO Steady-State Thermal and Voltage Analysis

Stage-1 MISO steady-state analysis was performed on the benchmark and study cases, and the incremental impact of the Study Projects in PJM TC1 Cluster was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Backbone and MISO LRTP Network Upgrades (NUs) were identified to mitigate severe thermal and voltage constraints. The selected Backbone and MISO LRTP NUs are called Base Case NUs.

Stage-1 steady-state analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI. PSS®E version 34.9.5 and TARA were used in the study.

2.1 Stage-1 MISO Analysis for 2026 Summer Peak Condition

Steady state AC contingency analysis was performed on the Stage-1 MISO AFSIS summer peak (SPK) study and benchmark cases developed in Section 1.1.

2.1.1 Stage-1 Summer Peak with 2000 MW IR

The Stage-1 summer peak with 2000 MW Injection Right (IR) MISO thermal and voltage detailed results are in Appendix B.1.1. There are several NERC Category P2-P7 contingencies causing voltage collapses (Table B-7).

The worst thermal and voltage constraints in summer peak IR condition are in Appendix B.1.2.

2.1.2 Stage-1 Summer Peak with 2000 MW WR

The Stage-1 summer peak with 2000 MW Withdrawal Right (WR) MISO thermal and voltage detailed results are in Appendix B.2.1. No voltage collapses were identified (Table B-16).

The worst thermal and voltage constraints in summer peak WR condition are in Appendix B.2.2.

2.2 Stage-1 MISO Analysis for 2026 Summer Shoulder Discharging Condition

Steady state AC contingency analysis was performed on the Stage-1 MISO AFSIS summer shoulder (SH) discharging study and benchmark cases developed in Section 1.1.

2.2.1 Stage-1 Summer Shoulder Discharging with 2000 MW IR

The Stage-1 summer shoulder discharging with 2000 MW Injection Right (IR) MISO thermal and voltage detailed results are in Appendix B.3.1. No voltage collapses were identified.

The worst thermal constraints in summer shoulder discharging IR condition are in Appendix B.3.2. No voltage constraints were identified in summer shoulder discharging IR condition.

2.2.2 Stage-1 Summer Shoulder Discharging with 2000 MW WR

The Stage-1 summer shoulder discharging with 2000 MW Withdrawal Right (WR) MISO thermal and voltage detailed results are in Appendix B.4.1. No voltage collapses were identified.

The worst thermal constraints in summer shoulder discharging WR condition are in Appendix B.4.2. No voltage constraints were identified in summer shoulder discharging WR condition.

2.3 Stage-1 MISO Analysis for 2026 Summer Shoulder Charging Condition

Steady state AC contingency analysis was performed on the Stage-1 MISO AFSIS summer shoulder (SH) charging study and benchmark cases developed in Section 1.1.

2.3.1 Stage-1 Summer Shoulder Charging with 2000 MW IR

The Stage-1 summer shoulder charging with 2000 MW Injection Right (IR) MISO thermal and voltage detailed results are in Appendix B.5.1. No voltage collapses were identified.

The worst thermal constraints in summer shoulder charging IR condition are in Appendix B.5.2. No voltage constraints were identified in summer shoulder charging IR condition.

2.3.2 Stage-1 Summer Shoulder Charging with 2000 MW WR

The Stage-1 summer shoulder charging with 2000 MW Withdrawal Right (WR) MISO thermal and voltage detailed results are in Appendix B.6.1. No voltage collapses were identified.

The worst thermal constraints in summer shoulder charging WR condition are in Appendix B.6.2. No voltage constraints were identified in summer shoulder charging WR condition

2.4 Summary of Stage-1 MISO Steady State Analysis

Stage-1 steady state analyses were performed on the MISO 2026 summer peak discharging, summer shoulder discharging, and summer shoulder charging scenarios. In each scenario, AF1-088 and AF2-008 MHVDC has two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from its POI. Table 2-1 lists Stage-1 worst thermal constraints in the combined scenarios. Stage-1 worst voltage constraints in the combined scenarios are in Appendix B.7.

Table 2-1: Stage-1 Combined Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF1-088&AF2-008, AG1-236, AF2-069, AF2-143, AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AF1-280, AF1-296, AF2-041, AF2-182, AF2-199, AF2-200, AF2-225, AF2-392, AG1-374, AG1-460, AG1-462, AG1-553,	J1180 POI - Sullivan 345 kV	1334.0	AMIL AEP	1577.0	118.2	CEII Redacted	P0	SUM WR
AF1-088&AF2-008, AF1-204	J1180 POI - Sullivan 345 kV	1466.0	AMIL AEP	1835.9	125.2	CEII Redacted	P1	SUM WR, SH Discharge WR, SH Charge WR
AF1-088&AF2-008	J1180 POI - Sullivan 345 kV	1466.0	AMIL AEP	1835.9	125.2	CEII Redacted	P2-P7	SUM WR, SH Discharge WR, SH Charge WR
AF1-088&AF2-008, AG1-236, AF2-069, AF2-143, AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AF1-280, AF1-296, AF2-041, AF2-182, AF2-199, AF2-200, AF2-225, AF2-392, AG1-374, AG1-460, AG1-462, AG1-553,	J1180 POI - Casey 345 kV	1334.0	AMIL	1347.6	101.0	CEII Redacted	P0	SUM WR

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF1-088&AF2-008, AF1-204	J1180 POI - Casey 345 kV	1466.0	AMIL	1603.6	109.4	CEII Redacted	P1	SUM WR
AF1-088&AF2-008	J1180 POI - Casey 345 kV	1466.0	AMIL	1603.6	109.4	CEII Redacted	P2-P7	SUM WR
AG1-410, AG1-411	J1586 POI - Argenta 345 kV	997.0	METC	1140.4	114.4	CEII Redacted	P1	SUM IR
AG1-410, AG1-411	J1586 POI - Tompkins 345 kV	1126.0	METC	1433.3	127.3	CEII Redacted	P1	SUM IR
AG1-297	Hubble - Batesville 138 kV	291.0	HE DEI	426.6	146.6	CEII Redacted	P1	SUM WR, SUM IR
AG1-297	Hubble - Wilmington 138 kV	291.0	HE DEI	388.0	133.3	CEII Redacted	P1	SUM WR, SUM IR
AF1-204	Cayuga - Eugene 345 kV	1374.0	DEI AEP	1537.9	111.9	CEII Redacted	P1	SH Discharge IR, SH Charge IR
AF1-204	Cayuga - Eugene 345 kV	1374.0	DEI AEP	1421.0	103.4	CEII Redacted	P2-P7	SH Discharge IR, SH Charge IR

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF1-204, AG1-226	Cayuga Sub - Cayuga 345 kV	1374.0	DEI	1486.1	108.2	CEII Redacted	P1	SH Discharge IR, SH Charge IR, SUM IR
AF1-204, AG1-226	Cayuga Sub - Cayuga 345 kV	1374.0	DEI	1384.3	100.8	CEII Redacted	P2-P7	SH Charge IR, SUM IR
AF1-204, AG1-226	Cayuga - Nucor 345 kV	1279.0	DEI	1523.3	119.1	CEII Redacted	P0	SUM WR, SUM IR
AF1-088&AF2-008, AG1-226, AF1-204, AE2-173, AE2-223, AE2-225, AE11-172, AG1-374	Cayuga - Nucor 345 kV	1279.0	DEI	1816.4	142.0	CEII Redacted	P1	SUM WR, SH Charge IR, SUM IR
AF1-088&AF2-008, AG1-226	Cayuga - Nucor 345 kV	1279.0	DEI	1881.0	147.1	CEII Redacted	P2-P7	SUM IR
AF1-204, AG1-226	Nucor - Whitst 345 kV	1195.0	DEI	1255.5	105.1	CEII Redacted	P0	SUM IR
AF1-088&AF2-008	Nucor - Whitst 345 kV	1195.0	DEI	1533.2	128.3	CEII Redacted	P1	SUM IR
AF1-088&AF2-008, AG1-226	Nucor - Whitst 345 kV	1195.0	DEI	1597.3	133.7	CEII Redacted	P2-P7	SUM IR
AG1-297	Greendale - Hidden Valley 138 kV	480.0	DEI	493.3	102.8	CEII Redacted	P1	SUM IR
AG1-297	Hidden Valley - Wilmington J 138 kV	501.0	DEI	502.7	100.3	CEII Redacted	P1	SUM IR

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AG1-297	Wilmington J - Wilmington 138 kV	291.0	DEI	380.2	130.7	CEII Redacted	P1	SUM WR, SUM IR
AF1-088&AF2-008	Petersburg - Sullivan 345 kV	1409.0	IPL AEP	1745.4	123.9	CEII Redacted	P1	SH Discharge IR, SH Charge IR, SUM IR
AG1-226	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2324.2	103.8	CEII Redacted	P1	SUM IR

Stage-1 MISO Steady-State Thermal and Voltage Analysis

Generator	Constraint	Rating	Owner	Worst Loading (MVA)	Worst Loading (%)	Contingency	Cont Type	Scenario
AG1-226	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2357.7	105.3	CEII Redacted	P2-P7	SUM IR
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	60.0	127.7	CEII Redacted	P0	SUM WR, SUM IR

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	85.3	181.4	CEII Redacted	P1	SUM WR, SH Discharge IR, SUM IR
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	85.0	181.0	CEII Redacted	P2-P7	SUM WR, SH Discharge IR, SUM IR
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	57.1	121.4	CEII Redacted	P0	SUM WR, SUM IR
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	81.6	173.6	CEII Redacted	P1	SUM WR, SH Discharge IR, SUM IR
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	81.4	173.2	CEII Redacted	P2-P7	SUM WR, SH Discharge IR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	55.4	135.2	CEII Redacted	P0	SUM WR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	79.6	194.1	CEII Redacted	P1	SUM WR, SH Discharge WR, SH Discharge IR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	79.4	193.6	CEII Redacted	P2-P7	SUM WR, SH Discharge WR, SH Discharge IR, SUM IR
AG1-410, AG1-411	Tompkins - Majestic 345 kV	1126.0	METC ITCT	1261.3	112.0	CEII Redacted	P1	SUM WR, SUM IR
AE2-261	Moro - Laclede NTP 138 kV	305.0	AMIL	481.3	157.8	CEII Redacted	P1	SUM IR
AE2-261	Moro - Laclede NTP 138 kV	305.0	AMIL	487.9	160.0	CEII Redacted	P2-P7	SUM IR
AE2-261	Wood River NE - Laclede NTP 138 kV	364.0	AMIL	469.0	128.9	CEII Redacted	P1	SUM IR

Stage-1 MISO Steady-State Thermal and Voltage Analysis

Generator	Constraint	Rating	Owner	Worst Loading (MVA)	Worst Loading (%)	Contingency	Cont Type	Scenario
AE2-261	Wood River NE - Laclede NTP 138 kV	364.0	AMIL	466.9	128.3	CEII Redacted	P2-P7	SUM IR

Section
3

Stage-1 NIPSCO LPC Analysis

3.1 NIPSCO LPC Criteria

For facilities owned by NIPSCO, NIPSCO Local Planning Criteria (LPC) analysis was also performed based on NIPSCO LPC criteria, which are listed below:

Individual Contribution Test:

- The contribution of the Distribution Factor of the Facility Connection, TSR, or Generation Retirement with magnitude of 3% or greater contributing to an overload on a NIPSCO facility. Or,

- The Contribution of a Facility Connection, TSR, or Generation Retirement on a NIPSCO facility is equal to or greater than 3% of the facility rating.

Cumulative Impact Test:

- The Facility Connections, TSRs, and Generation Retirements having a cumulative impact of at least 10% of the facility rating will be considered as impacting NIPSCO's transmission system.

3.2 Stage-1 NIPSCO LPC Contingency Analysis

Stage-1 NIPSCO LPC contingency analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios to identify additional thermal constraints on facilities owned by NIPSCO. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI. PSS®E version 34.9.5 and TARA were used in the study.

Based on the identified thermal constraints on NIPSCO facilities, additional Backbone and MISO LRTP Network Upgrades (NUs) were identified to mitigate severe thermal constraints on NIPSCO facilities.

3.2.1 Stage-1 NIPSCO LPC Summer Peak Results

NIPSCO LPC analysis was performed on the Stage-1 MISO AFSIS summer peak (SPK) study and benchmark cases developed in Section 1.1.

3.2.1.1 Stage-1 NIPSCO LPC Summer Peak with 2000 MW IR

The Stage-1 summer peak with 2000 MW Injection Right (IR) NIPSCO LPC thermal results are in Appendix C.1.

The NIPSCO LPC worst thermal constraints in summer peak IR condition are in Table C-4.

3.2.1.2 Stage-1 NIPSCO LPC Summer Peak with 2000 MW WR

The Stage-1 summer peak with 2000 MW Withdrawal Right (WR) NIPSCO LPC thermal results are in Appendix C.2.

The NIPSCO LPC worst thermal constraints in summer peak WR condition are in Table C-8.

3.2.2 Stage-1 NIPSCO LPC Summer Shoulder Discharging Results

NIPSCO LPC analysis was performed on the Stage-1 MISO AFSIS summer shoulder (SH) discharging study and benchmark cases developed in Section 1.1.

3.2.2.1 Stage-1 NIPSCO LPC Summer Shoulder Discharging with 2000 MW IR

The Stage-1 summer shoulder discharging with 2000 MW Injection Right (IR) NIPSCO LPC thermal results are in Appendix C.3.

The NIPSCO LPC worst thermal constraints in summer shoulder discharging IR condition are in Table C-12.

3.2.2.2 Stage-1 NIPSCO LPC Summer Shoulder Discharging with 2000 MW WR

The Stage-1 summer shoulder discharging with 2000 MW Withdrawal Right (WR) NIPSCO LPC thermal results are in Appendix C.4.

No NIPSCO LPC thermal constraints were identified in summer shoulder discharging WR condition.

3.2.3 Stage-1 NIPSCO LPC Summer Shoulder Charging Results

NIPSCO LPC analysis was performed on the Stage-1 MISO AFSIS summer shoulder (SH) charging study and benchmark cases developed in Section 1.1.

3.2.3.1 Stage-1 NIPSCO LPC Summer Shoulder Charging with 2000 MW IR

The Stage-1 summer shoulder charging with 2000 MW Injection Right (IR) NIPSCO LPC thermal results are in Appendix C.5.

The NIPSCO LPC worst thermal constraints in summer shoulder charging IR condition are in Table C-20.

3.2.3.2 Stage-1 NIPSCO LPC Summer Shoulder Charging with 2000 MW WR

The Stage-1 summer shoulder charging with 2000 MW Withdrawal Right (WR) NIPSCO LPC thermal results are in Appendix C.6.

No NIPSCO LPC thermal constraints were identified in summer shoulder charging WR condition.

3.3 Summary of Stage-1 NIPSCO LPC Analysis

Stage-1 NIPSCO LPC contingency analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios to identify additional thermal constraints on facilities owned by NIPSCO. In each scenario, AF1-088 and AF2-008 MHVDC has two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from its POI.

Based on the Stage-1 NIPSCO LPC 2026 summer peak, summer shoulder discharging, and summer shoulder charging analyses, Table 3-1 lists additional thermal constraints with maximum screened loading in combined scenarios identified in NIPSCO LPC analysis.

Table 3-1: Combined Stage-1 NIPSCO LPC Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF1-088&AF2-008, Cum.Impact NIPSCO	J2226 POI - Goodland 138 kV	287.0	NIPSCO	316.6	110.3	CEII Redacted	P1	SUM IR
AF1-088&AF2-008, Cum.Impact NIPSCO	J2226 POI - Goodland 138 kV	287.0	NIPSCO	311.1	108.4	CEII Redacted	P2-P7	SUM IR
AF1-088&AF2-008,, Cum.Impact NIPSCO	Wvrich - Rochester TP 69 kV	44.0	DEI NIPSCO	50.5	114.7	CEII Redacted	P1	SUM WR, SUM IR
AF2-142,AG1-236,AF2-069,AF2-143,AE1-114,AE1-172,AE2-173,AE2-223,AE2-261,AE2-321,AE2-341,AF1-030,AF1-280,AF1-296,AF2-041,AF2-095,AF2-182,AF2-199,AF2-200,AF2-225,AF2-226,AF2-319,AF2-349,AF2-350,AG1-127,AF2-392,AF2-441,AG1-118,AG1-374,AG1-460,AG1-462,AG1-553, Cum.Impact NIPSCO	Stillwell - Dumont 345 kV	1075.0	NIPSCO AEP	1159.4	107.9	CEII Redacted	P1	SUM WR, SUM IR

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
AF2-142,AG1-236,AF2-069,AF2-143,AE1-114,AE1-172,AE2-173,AE2-223,AE2-261,AE2-321,AE2-341,AF1-030,AF1-280,AF1-296,AF2-041,AF2-095,AF2-182,AF2-199,AF2-200,AF2-225,AF2-226,AF2-319,AF2-349,AF2-350,AG1-127,AF2-392,AF2-441,AG1-118,AG1-374,AG1-460,AG1-462,AG1-553, Cum.Impact NIPSCO	Stillwell - Dumont 345 kV	1075.0	NIPSCO	1285.2	119.6	CEII Redacted	P2-P7	SUM WR, SUM IR
AF1-088&AF2-008, Cum.Impact NIPSCO	Goodland - Reynold 138 kV	186.0	NIPSCO	301.2	161.9	CEII Redacted	P0	SH Discharge IR, SH Charge IR, SUM IR
AF1-088&AF2-008, Cum.Impact NIPSCO	Goodland - Reynold 138 kV	222.0	NIPSCO	370.0	166.7	CEII Redacted	P1	SH Discharge IR, SH Charge IR, SUM IR
AF1-088&AF2-008, Cum.Impact NIPSCO	Goodland - Reynold 138 kV	222.0	NIPSCO	335.6	151.2	CEII Redacted	P2-P7	SH Discharge IR, SH Charge IR, SUM IR
Cum.Impact NIPSCO	Goodland 138/69 kV xfmr	112.0	NIPSCO	260.6	232.6	CEII Redacted	P1	SUM IR
AF1-088&AF2-008, Cum.Impact NIPSCO	Leesburg - northeast 138 kV	222.0	NIPSCO	252.9	113.9	CEII Redacted	P1	SUM IR
Cum.Impact NIPSCO	Argos - Plymouth 69 kV	47.0	NIPSCO	57.0	121.2	CEII Redacted	P1	SUM WR, SUM IR

Stage-1 NIPSCO LPC Analysis

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Scenario
				(MVA)	(%)			
Cum.Impact NIPSCO	Argos - Rochester TP 69 kV	47.0	NIPSCO	54.3	115.4	CEII Redacted	P1	SUM WR, SUM IR

Section 4

Base Case Network Upgrades

Based on the MISO thermal and voltage constraints and NIPSCO LPC thermal constraints identified in the Stage-1 steady state analysis, following PJM Backbone Network Upgrades (Table 4-1), PJM System Impact Study Network Upgrades (Table 4-2), and MISO LRTP projects (Table 4-3) are justified and added to the Stage-1 study models to create Stage-2 study models. These added Network Upgrades are called Base Case Network Upgrades.

Table 4-1: PJM Backbone Network Upgrades

Project Name	Description
ComEd_s3011	Replace 345 kV open air straight bus with GIS in a breaker and half configuration (34 Circuit Breakers) at Goodings Grove with 80kA capability.
ComEd_b3811_Haumesser-W.Dekalb	Rebuild 138 kV from Haumesser Rd to H-452 Tap
B3775 Green Acre - Olive + St John	University Park-Olive-StJohn line Reconfiguration
AEP Jefferson-Clifty AEPSERG13	Add a second Jefferson 765/345kV XFMR connect to a parallel Jefferson - Clifty 345kV line

Table 4-2: PJM System Impact Study Network Upgrades

Facility	Area	MISO TO	Proposed Reinforcement by MISO TO
18MOROCCO (256583) [345 KV] to 02ALLEN (238530) [345 KV] ckt 1	METC/ATSI	METC	Remove sag. Ratings will be 1861/2124. Cost: $625,000. Restrictions at PJM Allen Junction needs to be removed. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.
05EUGENE (243221) [345 KV] to 08CAYSUB (249504) [345 KV] ckt 1	AEP/DEI	DEI	Currently working on new 4000A conductor with a rating of 2430 MV, the parallel line is not needed with the new conductor is approved. The cost to rebuild with the new conductor is $12M. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.
19MON12 (264612) [345 KV] to 02LALLENDORF (241901) [345 KV] ckt 1	ITCT/ATSI	ITCT	Reconductor ITCT section of Lallendorf-Monroe line. Post upgrade ratings will be 1677/2124. Cost: $43,500,000. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.

Base Case Network Upgrades

Table 4-3: MISO LRTP Projects

Project Name	Description
LRTP-16: Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.
LRTP-33: Greentown - Sorenson - Lulu	Install single circuit 765kV transmission line from the existing Greentown Substation to the existing Sorenson Substation, to the existing Lulu Substation.
LRTP-35: Southwest Indiana-Kentucky	Install double circuit 345kV transmission line from the existing Petersburg Substation to the new Pike County Substation. Install single circuit 345kV transmission line from the new Pike County Substation to the existing Duff Substation, to the existing Culley Substation, to the existing Reid EHV Substation.
LRTP-36: Southeast Indiana	Install single circuit 345kV transmission line from the new Madison County Substation to the existing Greensboro Substation. Install single circuit 138kV transmission line from the existing Decatur County Substation to the existing Greensburg Substation. Install double circuit 138kV transmission line from the existing Batesville Substation to the existing Hubbell Substation, to the existing Greendale Substation, to the existing Miami Fort Substation.
LRTP-37: Maywood - Belleau - MRPD - Sioux - Bugle	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Belleau Substation, to the new MRPD Substation, to the existing Sioux Substation, from the new MRPD Substation to the existing Bugle Substation.
LRTP-42: Burr Oak - Schahfer	Install single circuit 345kV transmission line from the existing Burr Oak Substation to the existing Schahfer Substation.

The Stage-2 study models include the Base Case Network Upgrades. Due to low voltages in areas around Jefferson 765 kV, Greentown 765 kV, and Sorenson 765 kV, line reactors in several 765 kV lines were turned off in all the Stage-2 study cases. These 765 kV lines are: Jefferson – Hanging Rock (243208 - 242924), Jefferson – Rockport (243208 - 243209), Dumont – Greentown (243206 – 243207), Greentown – Reynolds (243207 – 255204), Sorenson – Dumont (246999 – 243206).

Additional fictitious SVCs in PJM system were also added in the Stage-2 study cases. These fictitious SVCs are listed in Table 4-4.

Table 4-4: Fictitious SVCs in PJM System Added in Stage-2 Study Cases

Bus Number	Names	Area Number	Area Name	SPK Study IR	SPK Study WR	SH Discharge Study IR	SH Discharge Study WR	SH Charge Study IR	SH Charge Study WR
200009	JUNI 500	229	PL	500	100	None	None	None	None
243210	05SULLIVAN 765	205	AEP	700	500	400	400	400	400
314907	8DOOMS 500	345	DVP	1150	750	None	None	None	None
242925	05KAMMER 765	205	AEP	3000	2350	1400	1000	1050	700
242928	05MARYSV 765	205	AEP	1000	700	None	None	None	None
242924	05HANG R 765	205	AEP	1100	650	None	None	None	None
246999	05SORENS 765	205	AEP	850	350	None	None	None	None
290599	JEFFRSN_RG 765	205	AEP	950	350	None	None	None	None

Note: Unit of fictitious SVC size is MVar

With all the above Base Case Network Upgrades and model changes, the Stage-2 study models were developed. Stage-2 MISO steady-state analysis and NIPSCO LPC analysis will be performed on the Stage-2 study models.

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Section
5

Stage-2 MISO Steady-State Thermal and Voltage Analysis

Stage-2 MISO steady-state analysis was performed on the benchmark and Stage-2 study cases with Base Case Network Upgrades added. Additional MISO affected system thermal and voltage Network Upgrades were identified for Study Projects in PJM TC1 cluster.

Stage-2 MISO analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI. PSS®E version 34.9.5 and TARA were used in the study.

5.1 Stage-2 MISO Steady-State Analysis Results

5.1.1 Stage-2 MISO Results in Summer Peak with 2000 MW IR

The Stage-2 summer peak with 2000 MW Injection Right (IR) MISO thermal and voltage detailed results are in Appendix D.1.

The worst thermal and voltage constraints in summer peak IR condition are listed in Table 5-1, Table 5-2.

5.1.2 Stage-2 MISO Results in Summer Peak with 2000 MW IR

The Stage-2 summer peak with 2000 MW Withdrawal Right (WR) MISO thermal and voltage detailed results are in Appendix D.2.

The worst thermal constraints in summer peak WR condition are listed in Table 5-3. No voltage constraints were identified.

Table 5-1: Stage-2 SPK with 2000 MW IR Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
AF1-088&AF2-008, AF1-204, AG1-226	Cayuga - Nucor 345 kV	1279.0	DEI	1411.2	110.3	CEII Redacted	P0
AF1-088&AF2-008	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2405.4	107.4	CEII Redacted	P1
AG1-226	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2532.6	113.1	CEII Redacted	P2-P7
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	48.4	103.0	CEII Redacted	P0
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.4	156.2	CEII Redacted	P1
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.1	155.5	CEII Redacted	P2-P7
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	70.0	148.9	CEII Redacted	P1
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	69.8	148.5	CEII Redacted	P2-P7
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	44.6	108.8	CEII Redacted	P0
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	68.2	166.3	CEII Redacted	P1
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	67.9	165.6	CEII Redacted	P2-P7
AE2-261	Moro - Laclede NTP 138 kV	305.0	AMIL	428.4	140.5	CEII Redacted	P2-P7

Table 5-2: Stage-2 SPK with 2000 MW IR Worst Voltage Constraints

Bus			Owner	Vlow	Vhi	Benchmark	StudyCase	Delta (> 0.01 p.u.)	Contingency Details	Cont Type
						VCONT	VCONT			
249617	08GALAGH	230.0	208 DEI	0.90	1.07	0.9038	0.8936	-0.0102	CEII Redacted	P2-P7
249844	08SHOALS	138.0	208 DEI	0.90	1.05	0.9138	0.8986	-0.0152	CEII Redacted	P2-P7
249892	08AVONEA	138.0	208 DEI	0.90	1.05	0.9240	0.8994	-0.0246	CEII Redacted	P2-P7
253580	10NTVL16	161.0	210 SIGE	0.95	1.05	0.9430	0.9278	-0.0152	CEII Redacted	P1
253580	10NTVL16	161.0	210 SIGE	0.95	1.05	0.9333	0.9122	-0.0211	CEII Redacted	P2-P7

Table 5-3: Stage-2 SPK with 2000 MW WR Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
AF1-204	Cayuga - Nucor 345 kV	1279.0	DEI	1293.5	101.1	CEII Redacted	P1
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	47.8	101.7	CEII Redacted	P0
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.2	155.7	CEII Redacted	P1
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.0	155.3	CEII Redacted	P2-P7
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	69.9	148.7	CEII Redacted	P1
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	69.7	148.3	CEII Redacted	P2-P7
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	44.2	107.8	CEII Redacted	P0
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	68.1	166.1	CEII Redacted	P1
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	67.8	165.4	CEII Redacted	P2-P7

5.1.3 Stage-2 MISO Results in Summer Shoulder Discharging with 2000 MW IR

No MISO thermal constraints or voltage constraints were identified in Stage-2 summer shoulder discharging with 2000 MW Injection Right (IR) scenario.

5.1.4 Stage-2 MISO Results in Summer Shoulder Discharging with 2000 MW WR

No MISO thermal constraints or voltage constraints were identified in Stage-2 summer shoulder discharging with 2000 MW Withdrawal Right (WR) scenario.

5.1.5 Stage-2 MISO Results in Summer Shoulder Charging with 2000 MW IR

No MISO thermal constraints or voltage constraints were identified in Stage-2 summer shoulder charging with 2000 MW Injection Right (IR) scenario.

5.1.6 Stage-2 MISO Results in Summer Shoulder Charging with 2000 MW WR

No MISO thermal constraints or voltage constraints were identified in Stage-2 summer shoulder charging with 2000 MW Withdrawal Right (WR) scenario.

5.2 Summary of Stage-2 MISO Steady State Analysis

Stage-2 MISO analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI.

Table 5-4 lists worst thermal constraints in the combined scenarios, and Table 5-5 lists worst voltage constraints in the combined scenarios. Thermal Network Upgrades identified in the combined scenarios are listed in Table 5-6, and voltage Network Upgrades identified in the combined scenarios are listed in Table 5-7.

Table 5-4: Stage-2 Combined Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Cont Type	Scenario
				(MVA)	(%)		
AF1-088&AF2-008, AF1-204, AG1-226	Cayuga - Nucor 345 kV	1279.0	DEI	1411.2	110.3	P0	SUM IR
AF1-204	Cayuga - Nucor 345 kV	1279.0	DEI	1293.5	101.1	P1	SUM WR
AF1-088&AF2-008	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2405.4	107.4	P1	SUM IR
AG1-226	Reynold 765/345 kv xfmr	2239.0	NIPSCO	2532.6	113.1	P2-P7	SUM IR
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	48.4	103.0	P0	SUM WR, SUM IR
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.4	156.2	P1	SUM WR, SUM IR
AF1-176, AF2-396	Sturgi - Howe 69 kV	47.0	NIPSCO AEP	73.1	155.5	P2-P7	SUM WR, SUM IR
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	70.0	148.9	P1	SUM WR, SUM IR
AF1-176, AF2-396	Howe - North Lagrange 69 kV	47.0	NIPSCO	69.8	148.5	P2-P7	SUM WR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	44.6	108.8	P0	SUM WR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	68.2	166.3	P1	SUM WR, SUM IR
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	41.0	NIPSCO	67.9	165.6	P2-P7	SUM WR, SUM IR
AE2-261	Moro - Laclede NTP 138 kV	305.0	AMIL	428.4	140.5	P2-P7	SUM IR

Table 5-5: Stage-2 Combined Worst Voltage Constraints

Bus			Owner	Vlow	Vhi	Benchmark	StudyCase	Delta (> 0.01 p.u.)	Cont Type	Scenario
						VCONT	VCONT			
249617	08GALAGH	230.0	208 DEI	0.90	1.07	0.9038	0.8936	-0.0102	P2-P7	SUM IR
249844	08SHOALS	138.0	208 DEI	0.90	1.05	0.9138	0.8986	-0.0152	P2-P7	SUM IR
249892	08AVONEA	138.0	208 DEI	0.90	1.05	0.9240	0.8994	-0.0246	P2-P7	SUM IR
253580	10NTVL16	161.0	210 SIGE	0.95	1.05	0.9430	0.9278	-0.0152	P1	SUM IR
253580	10NTVL16	161.0	210 SIGE	0.95	1.05	0.9333	0.9122	-0.0211	P2-P7	SUM IR

Table 5-6: Thermal Constraints and Network Upgrades Identified in Stage-2 MISO Analysis

Generator	Constraint	Owner	Scenario	Mitigation	Cost ($)
AF1-088&AF2-008, AF1-204, AG1-226	Cayuga - Nucor 345 kV	DEI	SUM WR, SUM IR	MTEP Proj ID 50718: Rebuild with 954 ZTACSR @ 200C from Cayuga Gen Yard to Nucor. Upgrade terminal equipment accordingly.	$0
AF1-088&AF2-008, AG1-226	Reynold 765/345 kV xfmr	NIPSCO	SUM IR	2nd 765/345kV Transformer. MISO MTEP LRTP Tranche 2 Project.	$0
AF1-176, AF2-396	Sturgis - Howe 69 kV	NIPSCO AEP	SUM WR, SUM IR	Not valid. Howe–Sturgis 69kV line is retired	$0
AF1-176, AF2-396	Howe - North Lagrange 69 kV	NIPSCO	SUM WR, SUM IR	constraint is invalid after Howe-Sturgis 69kV retirement	$0
AF1-176, AF2-396	North Lagrange - Lagrange 69 kV	NIPSCO	SUM WR, SUM IR	constraint is invalid after Howe-Sturgis 69kV retirement	$0
AE2-261	Moro - Laclede NTP 138 kV	AMIL	SUM IR	MTEP project 50119, line rebuild. Assigned to DPP-2019 Central	$0

Table 5-7: Voltage Constraints and Network Upgrades Identified in Stage-2 MISO Analysis

Constraints	Network Upgrades	Owner	Cost ($)
Low voltages in area of Gallagher 230 kV	Install 144 MVAR cap bank at Gallagher substation.	DEI	$3,000,000
Low voltage in areas of Shoals 138 kV	Install 28.8 MVAR cap bank at Shoals substation.	DEI	$3,000,000
Low voltages in area of Avon East 138 kV	Install 28.8 MVAR cap bank at Avon East substation.	DEI	$3,000,000
Low voltages in area of Newtonville 161 kV	Not valid. SIGE has updated voltage criteria for our 161kV that goes down to 0.90 pu.	SIGE	$0

Section
6

Stage-2 NIPSCO LPC Analysis

Stage-2 NIPSCO LPC contingency analysis was performed on the benchmark and Stage-2 study cases with Base Case Network Upgrades added. Additional NIPSCO LPC thermal Network Upgrades were identified for Study Projects in PJM TC1 cluster.

Stage-2 NIPSCO LPC analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios to identify additional thermal constraints on facilities owned by NIPSCO. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI. PSS®E version 34.9.5 and TARA were used in the study.

6.1 Stage-2 NIPSCO LPC Analysis Results

6.1.1 Stage-2 NIPSCO LPC Summer Peak with 2000 MW IR

The Stage-2 summer peak with 2000 MW Injection Right (IR) NIPSCO LPC thermal results are in Appendix E.1.

The NIPSCO LPC worst thermal constraints in summer peak IR condition are in Table 6-1.

6.1.2 Stage-2 NIPSCO LPC Summer Peak with 2000 MW WR

The Stage-2 summer peak with 2000 MW Withdrawal Right (WR) NIPSCO LPC thermal results are in Appendix E.2.

The NIPSCO LPC worst thermal constraints in summer peak WR condition are in Table 6-2.

Stage-2 NIPSCO LPC Analysis

Table 6-1: Stage-2 SPK with 2000 MW IR NIPSCO LPC Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
Cum.Impact NIPSCO	Wvrich - Rochester TP 69 kV	44.0	DEI NIPSCO	54.1	123.0	CEII Redacted	P1
Cum.Impact NIPSCO	Argos - Plymouth 69 kV	47.0	NIPSCO	60.4	128.5	CEII Redacted	P1
Cum.Impact NIPSCO	Argos - Rochester TP 69 kV	47.0	NIPSCO	57.6	122.6	CEII Redacted	P1

Table 6-2: Stage-2 SPK with 2000 MW WR NIPSCO LPC Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type
				(MVA)	(%)		
AF1-088&AF2-008, Cum.Impact NIPSCO	Wvrich - Rochester TP 69 kV	44.0	DEI NIPSCO	54.7	124.3	CEII Redacted	P1
Cum.Impact NIPSCO	Argos - Plymouth 69 kV	47.0	NIPSCO	61.2	130.2	CEII Redacted	P1
Cum.Impact NIPSCO	Argos - Rochester TP 69 kV	47.0	NIPSCO	58.4	124.3	CEII Redacted	P1

6.1.3 Stage-2 NIPSCO LPC Summer Shoulder Discharging with 2000 MW IR

No NIPSCO LPC thermal constraints were identified in Stage-2 summer shoulder discharging with 2000 MW Injection Right (IR) scenario.

6.1.4 Stage-2 NIPSCO LPC Summer Shoulder Discharging with 2000 MW WR

No NIPSCO LPC thermal constraints were identified in Stage-2 summer shoulder discharging with 2000 MW Withdrawal Right (WR) scenario.

6.1.5 Stage-2 NIPSCO LPC Summer Shoulder Charging with 2000 MW IR

No NIPSCO LPC thermal constraints were identified in Stage-2 summer shoulder charging with 2000 MW Injection Right (IR) scenario.

6.1.6 Stage-2 NIPSCO LPC Summer Shoulder Charging with 2000 MW WR

No NIPSCO LPC thermal constraints were identified in Stage-2 summer shoulder charging with 2000 MW Withdrawal Right (WR) scenario.

6.2 Summary of Stage-2 NIPSCO LPC Analysis

Stage-2 NIPSCO LPC analysis was performed in summer peak, summer shoulder discharging, and summer shoulder charging scenarios to identify additional thermal constraints on facilities owned by NIPSCO. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI.

Table 6-3 lists worst NIPSCO LPC thermal constraints in the combined scenarios, Additional NIPSCO LPC Thermal Network Upgrades identified in the combined scenarios are listed in Table 6-4.

Table 6-3: Stage-2 Combined NIPSCO LPC Thermal Constraints, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Cont Type	Scenario
				(MVA)	(%)		
AF1-088&AF2-008, Cum.Impact NIPSCO	Wvrich - Rochester TP 69 kV	44.0	DEI NIPSCO	54.7	124.3	P1	SUM WR, SUM IR
Cum.Impact NIPSCO	Argos - Plymouth 69 kV	47.0	NIPSCO	61.2	130.2	P1	SUM WR, SUM IR
Cum.Impact NIPSCO	Argos - Rochester TP 69 kV	47.0	NIPSCO	58.4	124.3	P1	SUM WR, SUM IR

Table 6-4: NIPSCO LPC Thermal Constraints and Network Upgrades Identified in Stage-2 MISO Analysis

Generator	Constraint	Owner	Scenario	Mitigation	Cost ($)
AF1-088&AF2-008, Cum.Impact NIPSCO	Wvrich - Rochester TP 69 kV	DEI NIPSCO	SUM WR, SUM IR	DEI: Rebuild 1 mile of 69kV with 477ACSR/VR2 @ 100/120C the ratings assume that NIPSCO terminal upgrades would not limit our T-Line rating. $1.5M NIPSCO: Rebuild line, NIPSCO owns 0.037 miles of 0.9 mile line. NIPSCO portion included in Argos to Rochester tap mitigation/cost.	$1,500,000
Cum.Impact NIPSCO	Argos - Plymouth 69 kV	NIPSCO	SUM WR, SUM IR	Rebuild line, approx 10 miles	$12,654,948
Cum.Impact NIPSCO	Argos - Rochester TP 69 kV	NIPSCO	SUM WR, SUM IR	Rebuild line, approx 3.2 miles	$4,049,583

Section
7

Stability Analysis

Stability analysis was performed to evaluate transient stability and impact on the region of the Study Projects in PJM TC1 Cluster.

7.1 Procedure

7.1.1 Computer Programs

Stability analysis was performed using TSAT revision 23.0.

7.1.2 Methodology

A stability package representing 2026 summer peak (SPK), summer shoulder (SH) discharging, and summer shoulder charging scenarios with generating facilities in the PJM TC1 Cluster were created from DPP 2021 Central Area Phase 2 final stability package. In each scenario, AF1-088 and AF2-008 have two dispatch modes: 2000 MW Injection Right (IR) and 2000 MW Withdrawal Right (WR) from the POI. Disturbances were simulated to evaluate the transient stability and impact on the region of the Study Projects. MISO transient stability criteria and local TOs' planning criteria specified in MTEP21 were adopted for checking stability violations.

7.2 Model Development

Summer peak, summer shoulder discharging, and summer shoulder charging stability power flow models with either IR or WR are the same as the correspondent steady state models, which were developed as specified in Section 1.1. As mentioned in Section 1.1.2, line reactors in several 765 kV lines were turned off and several fictitious SVCs (Table 1-1) were added in PJM system in study cases due to low voltages in PJM system.

Due to low voltages in other areas in PJM system and stringent voltage requirements in stability study, additional line reactors in several 765 kV lines were turned off in all the stability study cases. These 765 kV lines are: Jefferson – Hanging Rock (243208 - 242924), Jefferson – Greentown (243208 - 243207), Jefferson – Rockport (243208 - 243209), Greentown – Reynolds (243207 – 255204), and Dumont – Greentown (243206 – 243207).

7.3 Disturbance Criteria

The stability simulations performed as part of this study considered all the regional and local contingencies listed in Table 7-1. Regional contingencies with pre-defined switching sequences were selected from the MISO MTEP21 study; switching sequences for local contingencies were developed based on the generic clearing times shown in Table 7-2. The admittance for local single line-to-ground (SLG) faults were estimated by assuming that the Thevenin impedance of the positive, negative and zero sequence networks at the fault point are equal.

Table 7-1: Regional and Local Disturbance Descriptions

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Table 7-2: Generic Clearing Time Assumption

Voltage Level (kV)	Primary Clearing Time (cycle)	Backup Clearing Time (cycle)
765 kV	4	11
345 kV	4	11
230 kV	5	13
161/138 kV	6	18
115 kV	6	20
69 kV	8	24

7.4 Performance Criteria

MISO transient stability criteria and local TOs' planning criteria specified in MTEP21 were adopted. All Study Generators in PJM TC1 Cluster must mitigate the stability constraints to obtain any type of Interconnection Service.

7.5 Summer Peak IR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer peak with 2000 MW Injection Right (IR) stability model.

Appendix F.1.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer peak with 2000 MW IR stability study results summary is in Appendix F.1.1, Table F-1.

Under all the simulated faults except the below ones, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder discharging IR stability study.

7.5.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-3), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-3: Generation Tripping Due to Instability in SPK IR

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7.5.2 Active and Reactive Power Oscillations at Merom Units 1 & 2

Under one NERC P4-2 contingency of “0179_C_DEI_P42”, active and reactive power output of Merom units 1 & 2 were oscillating after the fault was cleared. The power oscillations were caused by one remaining outlet at Merom 345 kV with around 1180 MW flow from Merom units 1 & 2, J2178, and J2270. Same power oscillations of Merom units 1 & 2 were also identified in the benchmark. No MISO AFSIS NU is required.

Table 7-4:Active and Reactive Power Oscillations at Merom Units 1 & 2 in SPK IR

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7.5.3 Stability Network Upgrades Identified in Summer Peak IR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer peak IR scenario. No MISO AFSIS stability NUs are required in summer peak IR stability study.

7.6 Summer Peak WR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer peak with 2000 MW Withdrawal Right (WR) stability model.

Appendix F.2.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer peak with 2000 MW WR stability study results summary is in Appendix F.2.1, Table F-2.

Under all the simulated faults except the below ones, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder discharging IR stability study.

7.6.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-5), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-5: Generation Tripping Due to Instability in SPK WR

CEII Redacted

7.6.2 Active and Reactive Power Oscillations at Merom Units 1 & 2

Under one NERC P4-2 contingency of "0179_C_DEI_P42", active and reactive power output of Merom units 1 & 2 were oscillating after the fault was cleared. The power oscillations were caused by one remaining outlet at Merom 345 kV with around 1180 MW flow from Merom units 1 & 2, J2178, and J2270. Same power oscillations of Merom units 1 & 2 were also identified in the benchmark. No MISO AFSIS NU is required.

Table 7-6:Active and Reactive Power Oscillations at Merom Units 1 & 2 in SPK WR

CEII Redacted

7.6.3 Stability Network Upgrades Identified in Summer Peak WR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer peak WR scenario. No MISO AFSIS stability NUs are required in summer peak WR stability study.

7.7 Summer Shoulder Discharging IR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer shoulder discharging with 2000 MW Injection Right (IR) stability model.

Appendix F.3.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer shoulder discharging with 2000 MW Injection Right (IR) stability study results summary is in Appendix F.3.1, Table F-3.

Under all the simulated faults except the below one listed in Table 7-7, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder discharging IR stability study.

7.7.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-7), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-7: Generation Tripping Due to Instability in SH Discharge IR

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7.7.2 Stability Network Upgrades Identified in Summer Shoulder Discharging IR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer shoulder discharging IR scenario. No MISO AFSIS stability NUs are required in summer shoulder discharging IR stability study.

7.8 Summer Shoulder Discharging WR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer shoulder discharging with 2000 MW Withdrawal Right (WR) stability model.

Appendix F.4.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer shoulder discharging with 2000 MW Withdrawal Right (WR) stability study results summary is in Appendix F.4.1, Table F-4.

Under all the simulated faults except the below one listed in Table 7-8, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder discharging WR stability study.

7.8.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-8), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-8: Generation Tripping Due to Instability in SH Discharge WR

CEII Redacted

7.8.2 Stability Network Upgrades Identified in Summer Shoulder Discharging WR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer shoulder discharging WR scenario. No MISO AFSIS stability NUs are required in summer shoulder discharging WR stability study.

7.9 Summer Shoulder Charging IR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer shoulder charging with 2000 MW Injection Right (IR) stability model.

Appendix F.5.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer shoulder charging with 2000 MW Injection Right (IR) stability study results summary is in Appendix F.5.1, Table F-5.

Under all the simulated faults except the below one listed in Table 7-9, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder charging IR stability study.

7.9.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-9), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-9: Generation Tripping Due to Instability in SH Charge IR

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7.9.2 Stability Network Upgrades Identified in Summer Shoulder Charging IR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer shoulder charging IR scenario. No MISO AFSIS stability NUs are required in summer shoulder charging IR stability study.

7.10 Summer Shoulder Charging WR Stability Results

The contingencies listed in Table 7-1 were simulated using the summer shoulder charging with 2000 MW Withdrawal Right (WR) stability model.

Appendix F.6.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer shoulder charging with 2000 MW Withdrawal Right (WR) stability study results summary is in Appendix F.6.1, Table F-6.

Under all the simulated faults except the below one listed in Table 7-10, simulations are transiently stable, transient period voltage criteria are met, oscillations are well damped. No stability constraints were identified.

The following stability related issues were identified in the summer shoulder charging WR stability study.

7.10.1 Generation Tripping Due to Instability

Under one NERC Category P5 contingency (Table 7-10), Ghent unit 1 (324017) in LG&E was tripped due to instability. The same instability tripping also occurred in benchmark case. No MISO AFSIS NU is required.

Table 7-10: Generation Tripping Due to Instability in SH Charge WR

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7.10.2 Stability Network Upgrades Identified in Summer Shoulder Charging WR Scenario

In summary, no MISO Affected System stability constraints were identified in the summer shoulder charging WR scenario. No MISO AFSIS stability NUs are required in summer shoulder charging WR stability study.

7.11 Summary of Transient Stability Analysis

Based on the MISO 2026 summer peak, summer shoulder discharging, and summer shoulder charging scenarios with either IR or WR transient stability analyses, no transient stability constraints were identified for the Study Projects in PJM TC1 Cluster; no MISO AFSIS stability NUs are required for the PJM TC1 projects.

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Section
8

Short Circuit Screening Analysis

Short circuit screening analysis was conducted by comparing three phase fault currents in the benchmark and study cases for the Study Projects in TC1 Cluster. Several AMIL buses listed below were flagged for some PJM TC1 projects. These impacting Study Projects are listed in Table 8-1.

1. 9.5% (SSH) & 10.1% (SUM) at AMIL 345 kV bus 41804 ‘J1180 POI’
2. 2.3% (SSH) & 2.2% (SUM) at AMIL 345 kV bus 346809 ‘7CASEY’
3. 1.5% (SSH) & 1.3% (SUM) at AMIL 345 kV bus 72640 ‘J1263 POI’

Table 8-1: Impacting Study Projects Screened in Short Circuit Analysis

Impacting Study Projects
AF1-088
AF1-204
AF2-008
AG1-226
AG1-297

Ameren confirmed that the related breakers can handle the 5% fault current increase. Therefore, mitigation or further study is not required.

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Section 9

Contingent Facilities

Table 9-1 describes transmission assumptions modeled in the studies that are deemed necessary to mitigate the thermal and voltage violations identified in the study.

For the study projects that are required to mitigate thermal violations, the projects should not be allowed to come into service before the required Network Upgrades are in service, unless a MISO restudy removes the mitigation requirement from the project, or an interim limit was provided to the project through MISO Annual ERIS process.

Contingent Facilities

Table 9-1: Identified Contingent Facilities and Conditional Projects

MTEP ID	MTEP Cycle	Project Name	Description	Status	Expected ISD	Conditional Projects
23418	MTEP21	LRTP-16: Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.	M2 - Appendix A Approved	6/1/2029	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AE2-321, AE2-341, AF1-030, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-095, AF2-142, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-226, AF2-319, AF2-349, AF2-350, AF2-392, AF2-441, AG1-118, AG1-127, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553
50566	MTEP24	LRTP-33: Greentown - Sorenson - Lulu	Install single circuit 765kV transmission line from the existing Greentown Substation to the existing Sorenson Substation, to the existing Lulu Substation.	M2 - Appendix A Approved	6/1/2033	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AE2-321, AE2-341, AF1-030, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-095, AF2-142, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-226, AF2-319, AF2-349, AF2-350, AF2-392, AF2-441, AG1-118, AG1-127, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553
50568	MTEP24	LRTP-35: Southwest Indiana-Kentucky	Install double circuit 345kV transmission line from the existing Petersburg Substation to the new Pike County Substation. Install single circuit 345kV transmission line from the new Pike County Substation to the existing Duff Substation, to the existing Culley Substation, to the existing Reid EHV Substation.	M2 - Appendix A Approved	6/1/2032	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-392, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553
50569	MTEP24	LRTP-36: Southeast Indiana	Install single circuit 345kV transmission line from the new Madison County Substation to the existing Greensboro Substation. Install single circuit 138kV transmission line from the existing Decatur County Substation to the existing Greensburg Substation. Install double circuit 138kV transmission line from the existing Batesville Substation to the existing Hubbell	M2 - Appendix A Approved	6/1/2032	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-392, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553

MTEP ID	MTEP Cycle	Project Name	Description	Status	Expected ISD	Conditional Projects
			Substation, to the existing Greendale Substation, to the existing Miami Fort Substation.			
50570	MTEP24	LRTP-37: Maywood - Belleau - MRPD - Sioux - Bugle	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Belleau Substation, to the new MRPD Substation, to the existing Sioux Substation, from the new MRPD Substation to the existing Bugle Substation.	M2 - Appendix A Approved	6/1/2032	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-392, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553
50575	MTEP24	LRTP-42: Burr Oak - Schahfer	Install single circuit 345kV transmission line from the existing Burr Oak Substation to the existing Schahfer Substation.	M2 - Appendix A Approved	6/1/2032	AE1-114, AE1-172, AE2-173, AE2-223, AE2-261, AE2-321, AE2-341, AF1-030, AF1-088, AF1-204, AF1-280, AF1-296, AF2-008, AF2-041, AF2-069, AF2-095, AF2-142, AF2-143, AF2-182, AF2-199, AF2-200, AF2-225, AF2-226, AF2-319, AF2-349, AF2-350, AF2-392, AF2-441, AG1-118, AG1-127, AG1-226, AG1-236, AG1-297, AG1-374, AG1-410, AG1-411, AG1-460, AG1-462, AG1-553
50718	MTEP25	Rebuild Cayuga to Nucor 345 kV line	Line rebuild (~32.3mi) to bundled 954ACSS conductor or 4000A equivalent.	M2 - Appendix A Approved	6/1/2029	AF1-088, AF2-008, AF1-204, AG1-226
50573	MTEP24	LRTP-40: Sub T - Woodford County - Collins & Reynolds	Conditional Facility ID: 51192, Add 1-765/345kV 2250MVA transformer which will be connected to the 765kV south bus. Add 1-765kV circuit breaker for the new Transformer.	M2 - Appendix A Approved	6/1/2034	AF1-088, AF2-008, AG1-226
50119	MTEP25	Moro-Wood River-1436 138 kV Line Rebuild	DPP studies have identified the need for the Moro – Laclede N Tap rebuild project, currently assigned to DPP-2019 Central	M1-Proposed	6/30/2028	AE2-261

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Section
10

Network Upgrades and Cost Allocation

10.1 Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

10.2 Cost Allocation Methodology

Costs of AFSIS Network Upgrades are allocated based on MISO Network Upgrade cost allocation methodology, which is detailed in the MISO Generation Interconnection Business Practices Manual BPM-015.

10.3 AFSIS Network Upgrades Required for the PJM TC1 Projects

MISO Affected System (AFS) Network Upgrades for PJM TC1 Cluster were identified based on MISO criteria and NIPSCO LPC criteria. The MISO AFS steady state NUs include MISO thermal NUs and voltage NUs identified in the MISO steady state analysis, and NIPSCO LPC NUs identified in the NIPSCO LPC study.

Based on the MISO 2026 summer peak, summer shoulder discharging, and summer shoulder charging scenarios with either IR or WR transient stability analyses, no transient stability constraints were identified for the Study Projects in PJM TC1 Cluster; no MISO AFSIS stability NUs are required for the PJM TC1 projects.

Short circuit screening analysis was conducted by comparing three phase fault currents in the benchmark and study cases for the Study Projects in TC1 Cluster. Several AMIL buses were flagged for some PJM TC1 projects. Additional short circuit studies may be required pending Ameren's review.

Contingent MTEP facilities and Network Upgrades were identified, as listed in Section 9.

The total costs of MISO AFS Network Upgrades for PJM TC1 Cluster are summarized in Table 10-1.

Table 10-1: Summary of MISO AFS Network Upgrades

Category of Network Upgrades	Cost ($)
Base Case Network Upgrades	$0
Thermal Network Upgrades Identified in MISO Steady-State Analysis	$0
Voltage Network Upgrades Identified in MISO Steady-State Analysis	$9,000,000
Network Upgrades Identified in NIPSCO LPC Analysis	$18,204,531
Network Upgrades Identified in Stability Analysis	$0
Network Upgrades Identified in Short Circuit Analysis	$0
Total	**$27,204,531**

It should be noted that a restudy may be required if significant changes to the study assumptions occur, including but not limited to, interconnection request withdrawals and/or changes to higher-queued Network Upgrades included in the Base Case, and changes to the Contingent Network Upgrade.

For the study projects that are required to mitigate thermal violations, the projects should not be allowed to come into service before the required Network Upgrades are in service, unless a MISO restudy removes the mitigation requirement from the project, or an interim limit is provided to the project through MISO Annual ERIS process.

For projects that are required to mitigate voltage or stability violations, the projects should not be allowed to come into service before the required Network Upgrades are in service, unless a MISO restudy removes the mitigation requirement from the project, or an interim limit is provided to the project through MISO Annual ERIS process.

Base Case Network Upgrades are listed in Table 10-2 to Table 10-4.

Table 10-2: PJM Backbone Network Upgrades

Project Name	Description
ComEd_s3011	Replace 345 kV open air straight bus with GIS in a breaker and half configuration (34 Circuit Breakers) at Goodings Grove with 80kA capability.
ComEd_b3811_Haumesser-W.Dekalb	Rebuild 138 kV from Haumesser Rd to H-452 Tap
B3775 Green Acre - Olive + St John	University Park-Olive-StJohn line Reconfiguration
AEP Jefferson-Clifty AEPSERG13	Add a second Jefferson 765/345kV XFMR connect to a parallel Jefferson - Clifty 345kV line

Table 10-3: PJM System Impact Study Network Upgrades

Facility	Area	MISO TO	Proposed Reinforcement by MISO TO
18MOROCCO (256583) [345 KV] to 02ALLEN (238530) [345 KV] ckt 1	METC/ATSI	METC	Remove sag. Ratings will be 1861/2124. Cost: $625,000. Restrictions at PJM Allen Junction needs to be removed. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.
05EUGENE (243221) [345 KV] to 08CAYSUB (249504) [345 KV] ckt 1	AEP/DEI	DEI	Currently working on new 4000A conductor with a rating of 2430 MV, the parallel line is not needed with the new conductor is approved. The cost to rebuild with the new conductor is $12M. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.
19MON12 (264612) [345 KV] to 02LALLENDORF (241901) [345 KV] ckt 1	ITCT/ATSI	ITCT	Reconductor ITCT section of Lallendorf-Monroe line. Post upgrade ratings will be 1677/2124. Cost: $43,500,000. PJM SIS identified upgrade. The cost allocation of the upgrade will be determined by PJM in their System Impact Study report.

Table 10-4: MISO LRTP Projects

Project Name	Description
LRTP-16: Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.
LRTP-33: Greentown - Sorenson - Lulu	Install single circuit 765kV transmission line from the existing Greentown Substation to the existing Sorenson Substation, to the existing Lulu Substation.
LRTP-35: Southwest Indiana-Kentucky	Install double circuit 345kV transmission line from the existing Petersburg Substation to the new Pike County Substation. Install single circuit 345kV transmission line from the new Pike County Substation to the existing Duff Substation, to the existing Culley Substation, to the existing Reid EHV Substation.
LRTP-36: Southeast Indiana	Install single circuit 345kV transmission line from the new Madison County Substation to the existing Greensboro Substation. Install single circuit 138kV transmission line from the existing Decatur County Substation to the existing Greensburg Substation. Install double circuit 138kV transmission line from the existing Batesville Substation to the existing Hubbell Substation, to the existing Greendale Substation, to the existing Miami Fort Substation.
LRTP-37: Maywood - Belleau - MRPD - Sioux - Bugle	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Belleau Substation, to the new MRPD Substation, to the existing Sioux Substation, from the new MRPD Substation to the existing Bugle Substation.

Project Name	Description
LRTP-42: Burr Oak - Schahfer	Install single circuit 345kV transmission line from the existing Burr Oak Substation to the existing Schahfer Substation.

MISO AFSIS Network Upgrades for PJM TC1 Cluster are listed below.

Table 10-5: MISO Steady-State Thermal NUs and Cost

Constraint	Owner	Mitigation	Cost ($)
Cayuga - Nucor 345 kV	DEI	MTEP Proj ID 50718: Rebuild with 954 ZTACSR @ 200C from Cayuga Gen Yard to Nucor. Upgrade terminal equipment accordingly.	$0
Reynold 765/345 kV xfmr	NIPSCO	2nd 765/345kV Transformer. MISO MTEP LRTP-40 Project.	$0
Sturgis - Howe 69 kV	NIPSCO AEP	Not valid. Howe–Sturgis 69kV line is retired	$0
Howe - North Lagrange 69 kV	NIPSCO	constraint is invalid after Howe-Sturgis 69kV retirement	$0
North Lagrange - Lagrange 69 kV	NIPSCO	constraint is invalid after Howe-Sturgis 69kV retirement	$0
Moro - Laclede NTP 138 kV	AMIL	MTEP project 50119, line rebuild. Assigned to DPP-2019 Central	$0

Table 10-6: MISO Steady-State Voltage NUs and Cost

Constraints	Network Upgrades	Owner	Cost ($)
Low voltages in area of Gallagher 230 kV	Install 144 MVAR cap bank at Gallagher substation.	DEI	$3,000,000
Low voltage in areas of Shoals 138 kV	Install 28.8 MVAR cap bank at Shoals substation.	DEI	$3,000,000
Low voltages in area of Avon East 138 kV	Install 28.8 MVAR cap bank at Avon East substation.	DEI	$3,000,000
Low voltages in area of Newtonville 161 kV	Not valid. SIGE has updated voltage criteria for our 161kV that goes down to 0.90 pu.	SIGE	$0

Table 10-7: NIPSCO LPC Thermal NUs and Cost

Constraint	Owner	Mitigation	Cost ($)
Wvrich - Rochester TP 69 kV	DEI NIPSCO	DEI: Rebuild 1 mile of 69kV with 477ACSR/VR2 @ 100/120C the ratings assume that NIPSCO terminal upgrades would not limit our T-Line rating. $1.5M NIPSCO: Rebuild line, NIPSCO owns 0.037 miles of 0.9 mile line. NIPSCO portion included in Argos to Rochester tap mitigation/cost.	$1,500,000
Argos - Plymouth 69 kV	NIPSCO	Rebuild line, approx 10 miles	$12,654,948
Argos - Rochester TP 69 kV	NIPSCO	Rebuild line, approx 3.2 miles	$4,049,583

Table 10-8: MISO Transient Stability NUs and Cost

Network Upgrades	Owner	Cost ($)
No MISO AFS stability NUs		$0

Table 10-9: MISO Short Circuit Network Upgrades

SC Screening Results	Owner	Cost ($)
9.5% (SSH) & 10.1% (SUM) at AMIL 345 kV bus 41804 'J1180 POI'	Ameren	TBD
2.3% (SSH) & 2.2% (SUM) at AMIL 345 kV bus 346809 '7CASEY'	Ameren	TBD
1.5% (SSH) & 1.3% (SUM) at AMIL 345 kV bus 72640 'J1263 POI'	Ameren	TBD

10.4 Cost Allocation

The calculated Distribution Factor (DF) results, voltage impact, and MW contribution on each MISO Affected System constraint are in Appendix G.1. The cost allocation for each NU is calculated based on the contribution of each generating facility, as detailed in Appendix G.2.

Assuming all generation projects in the PJM TC1 Cluster advance, a summary of the costs for total MISO AFSIS NUs allocated to each generation project is listed in Table 10-10.

No injection is allowed for the projects until the allocated Network Upgrade(s) are in service, except for a revised report provided by MISO removing the requirements, or an interim limit provided for the projects through MISO Annual ERIS or Quarterly Operating Limit studies.

Table 10-10: Summary of AFSIS NU Costs Allocated to Each Generation Project in PJM TC1 Cluster

PJM Project #	MW Energy	Total Cost of AFSIS NU per Project ($)
AE1-114	150	$82,193
AE1-172	255	$136,517
AE2-173	50	$154,719
AE2-223	150	$73,760
AE2-261	299	$733,666
AE2-308	100	$0
AE2-321	100	$368,306
AE2-325	52.2	$249,655
AE2-341	150	$567,614
AF1-030	100	$375,624

PJM Project #	MW Energy	Total Cost of AFSIS NU per Project ($)
AF1-088	1000	$3,076,352
AF2-008	1000	$3,076,352
AF1-161	50	$239,991
AF1-176	300	$1,496,302
AF1-204	255	$69,943
AF1-233	188.5	$0
AF1-280	200	$681,511
AF1-296	190.89	$95,168
AF2-041	300	$1,062,419
AF2-068	150	$8,357
AF2-069	8.4	$3,175
AF2-095	144	$597,955
AF2-111	250	$0
AF2-126	12	$2,025
AF2-142	150	$589,247
AF2-143	150	$575,325
AF2-173	140	$8,357
AF2-177	200	$0
AF2-182	300	$1,018,422
AF2-199	100	$350,908
AF2-200	200	$710,842
AF2-225	150	$464,158
AF2-226	50	$204,662
AF2-307	64.2	$0
AF2-319	50	$204,662
AF2-335	100	$8,357
AF2-349	300	$1,094,362
AF2-350	100	$419,501
AF2-388	200	$19,677
AF2-392	199	$105,428
AF2-396	200	$973,463
AF2-407	300	$0
AF2-441	200	$910,924

PJM Project #	MW Energy	Total Cost of AFSIS NU per Project ($)
AG1-118	300	$1,111,779
AG1-127	95.1	$346,850
AG1-226	450	$1,224,007
AG1-236	180	$85,931
AG1-297	300	$0
AG1-320	82	$5,660
AG1-341	106	$16,981
AG1-354	150	$16,981
AG1-367	100	$16,713
AG1-374	300	$895,200
AG1-375	100	$14,686
AG1-410	300	$23,042
AG1-411	100	$0
AG1-433	100	$0
AG1-436	125	$652,243
AG1-447	55	$291,870
AG1-460	30	$72,566
AG1-462	255	$798,388
AG1-471	54	$5,660
AG1-526	222	$0
AG1-553	260	$816,076
Total	**12272.29**	**$27,204,531**

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Appendix
A

Model Development for Steady-State and Stability Analysis

A.1 Removed Recently Retired MISO Generation

Table A-1: Removed Recently Retired MISO Generation

Unit(s) Description	State	Power Flow Area	Bus Name	Bus Number	Unit ID	Derate To MW	Requested Change of Status
Genoa Unit 3	WI	DPC	GENOA53G	681522	3	0	Retirement
Grand Tower Units 1-4	IL	AMIL	1GRTW 1	347170	1	0	Retirement
Grand Tower Units 1-4	IL	AMIL	1GRTW 2	347171	2	0	Retirement
Grand Tower Units 1-4	IL	AMIL	1GRTW 3	347168	3	0	Retirement
Grand Tower Units 1-4	IL	AMIL	1GRTW 4	347169	4	0	Retirement
Moulton and Champepadan Wind	MN	GRE	GRE-CHANWNDW	615108	W	0	Retirement
Petersburg Unit 2	IN	IPL	PETERSBURG 2	254812	2	450	Retirement
Meramec CTG 2	MO	AMMO	1MER 6	345172	6	0	Retirement
St. Clair Unit 2,3,6 and 7	MI	ITCT	19SC2	264861	2	0	Retirement
St. Clair Unit 2,3,6 and 7	MI	ITCT	19SC3	264860	3	0	Retirement
St. Clair Unit 2,3,6 and 7	MI	ITCT	19SC6	264858	6	0	Retirement
St. Clair Unit 2,3,6 and 7	MI	ITCT	19SC7	264857	7	0	Retirement
Portage CT	MI	UPPC (ATC)	PORTAGE CT	698763	1	0	Retirement
Elk River Station	MN	GRE	GRE-ELK RIV869	615020	1	0	Retirement
Elk River Station	MN	GRE	GRE-ELK RIV869	615020	2	0	Retirement
Elk River Station	MN	GRE	GRE-ELK RIV869	615020	3	0	Retirement
Boswell Units 1 and 2	MN	MP	BOSWE71G	608776	1	0	Retirement
Boswell Units 1 and 2	MN	MP	BOSWE72G	608777	2	0	Retirement
Schahfer Unit 14 & 15	IN	NIPS	17SCHAFER-14	255238	14	0	Retirement
Schahfer Unit 14 & 15	IN	NIPS	17SCHAFER-15	255237	15	0	Retirement
River Rouge Unit 3	MI	ITCT	19RRG3	264867	3	0	Retirement

Unit(s) Description	State	Power Flow Area	Bus Name	Bus Number	Unit ID	Derate To MW	Requested Change of Status
Dallman Units 31 & 32	IL	CWLP	1DALMAN 31	343549	1	0	Retirement
Dallman Units 31 & 32	IL	CWLP	1DALMAN 32	343550	2	0	Retirement
Petersburg Unit 1	IN	IPL	PETERSBURG 1	254811	1	0	Retirement
Bailly Unit 10	IN	NIPS	17BAILLY-10	255246	10	0	Retirement
Hancock Unit 11-4	MI	ITCT	HANCK11BPKR	269321	4	0	Retirement
Community Wind North (G586)	MN	XEL	G586 - CWN 1	600130	W	13.2	Retirement
Community Wind North (G586)	MN	XEL	G586 - CWN 2	600131	W	13.2	Retirement
Jeffers Wind (G442)	MN	XEL	G442 JEFFERW	600124	W	44	Retirement
Granite City Units 1,2,3,4	MN	XEL	GRNT CTY 1G	600126	1	0	Retirement
Granite City Units 1,2,3,4	MN	XEL	GRNT CTY 1G	600126	2	0	Retirement
Granite City Units 1,2,3,4	MN	XEL	GRNT CTY 2G	600127	3	0	Retirement
Granite City Units 1,2,3,4	MN	XEL	GRNT CTY 2G	600127	4	0	Retirement
St. Clair Unit 1	MI	ITCT	19SC1	264862	1	0	Retirement
Bailly 7 & 8	IN	NIPS	17BAILLY-7	255234	7	0	Retirement
Bailly 7 & 8	IN	NIPS	17BAILLY-8	255235	8	0	Retirement
Stoneman 1 & 2	WI	DPC	STONE	186860	1	0	Retirement

A.2 Removed MISO / CIPCO Recently Withdrawn Generation Projects

Table A-2: Removed MISO North / CIPCO Recently Withdrawn Generation Projects

Project #	Bus Number	Bus Name	Id
J1191	41910	J1191 GEN 0.6000	1
J1231	42310	J1231 GEN 0.6450	1
J1516	45160	J1516 GEN 0.6300	1
J1860	48600	J1860 GEN 0.6900	1
J1862	48620	J1862 GEN 0.6900	1
J1980	49800	J1980 GEN 0.6300	1
J2056	50560	J2056 GEN1 0.6600	1
J2056	50561	J2056 GEN2 0.6600	1
J2117	51170	J2117 GEN 0.6300	ES
J2119	51190	J2119 GEN1 0.6000	1
J2279	52790	J2279 GEN1 0.6600	1
J2279	52791	J2279 GEN2 0.6600	1
J801	88011	J801 0.5500	PV
J974	89740	J974 GEN 0.6900	1
J974	89741	J974 GEN1 0.6900	1
IR37	800160	IR37 GEN 0.6300	1

A.3 Removed MPC Recently Withdrawn Generation Projects

Table A-3: Removed MPC Recently Withdrawn Generation Projects

Projects	MW	Generation Type	Town or County	State	Point of Interconnection	Pmax
MPC04300	400	Wind	Steele	ND	Center-Prairie 345 kV	400

A.4 Added AECI Prior Queued Generation Projects

Table A-4: Added AECI Prior Queued Generation Projects

Projects	Status	Location	Size (MW)	Fuel Type	Proposed I/C Location	Notes	Pmax
GIA-116	GIA	New Madrid County, MO	26	CC	St Francis 161 kV	uprating of existing units	275.5
GIA-117	GIA	New Madrid County, MO	46	CC	St Francis 161 kV	uprating of existing units	275.5

A.5 Updates of LG&E Prior Queued Generation Projects

Table A-5: LG&E Withdrawn and Prior Queued Generation Projects

Project	Status	MW	Fuel Type	State	Area	Point of Interconnection
LGE-GIS-2019-025	LGIA Signed	98.42	Solar	KY	LGE	Bardstown - Brown CT 138 kV
LGE-GIS-2021-007	suspension	120	Solar/Battery, battery doe does not charge from the grid	KY	LGE	Grahamville 161kV
LGE-GIS-2019-004	terminated	200	Solar/Battery, battery does not charge from the grid	KY	LGE	Hardinsburg 138 kV
LGE-GIS-2019-008	terminated	100	Solar	KY	LGE	North Princeton 161kV

A.6 Removed PJM Recently Withdrawn Prior Queued Generation Projects

Table A-6: PJM Withdrawn Generation Projects

Prj ID	Bus Number	Bus Name	Id	Status
AD1-043	934161	AD1-043 C O1138.00	1	Withdrawn
AD1-031	934054	AD1-031 GEN 0.5500	1	Withdrawn
AE2-218	942061	AE2-218 C 138.00	1	Withdrawn
AE1-070	938511	AE1-070 1 345.00	1	Withdrawn
AE1-070	938521	AE1-070 2 345.00	2	Withdrawn
AE1-246	940045	AE1-246 0.6000	1	Withdrawn
AE1-246	940046	AE1-246 BAT0.6000	1	Withdrawn
AE2-138	941411	AE2-138 C 345.00	1	Withdrawn
AE2-138	941412	AE2-138 BAT345.00	1	Withdrawn
AE2-275	942591	AE2-275 C O1138.00	1	Withdrawn
AE2-275	942592	AE2-275 BAT138.00	1	Withdrawn
AF1-116	944511	AF1-116 C 161.00	1	Withdrawn
AF1-200	945352	AF1-200 NFTW345.00	1	Withdrawn
AF1-221	945561	AF1-221 C O1138.00	1	Withdrawn
AF1-314	946501	AF1-314 138.00	1	Withdrawn
AF2-070	957761	AF2-070 138.00	1	Withdrawn
AF2-090	957961	AF2-090 C 138.00	1	Withdrawn
AF2-094	958001	AF2-094 C 138.00	1	Withdrawn
AF2-094	958002	AF2-094 BAT 138.00	1	Withdrawn
AF2-096	958021	AF2-096 C 345.00	1	Withdrawn
AF2-096	958022	AF2-096 BAT 345.00	1	Withdrawn
AF2-137	958431	AF2-137 C 765.00	1	Withdrawn
AF2-201	959101	AF2-201 WIND138.00	1	Withdrawn
AF2-201	959102	AF2-201SOLAR138.00	1	Withdrawn
AF2-204	959131	AF2-204 C 138.00	1	Withdrawn
AF2-204	959132	AF2-204 BAT138.00	1	Withdrawn
AF2-209	959181	AF2-209 C 138.00	1	Withdrawn
AF2-209	959182	AF2-209 BAT138.00	1	Withdrawn
AF2-260	959691	AF2-260 C 69.000	1	Withdrawn

Prj ID	Bus Number	Bus Name	Id	Status
AF2-321	960301	AF2-321 C 138.00	1	Withdrawn
AF2-329	960381	AF2-329 138.00	1	Withdrawn
AF2-348	960571	AF2-348 C 345.00	1	Withdrawn
AF2-355	960641	AF2-355 C O1345.00	1	Withdrawn
AF2-363	960721	AF2-363 C O1138.00	1	Withdrawn
AF2-391	961001	AF2-391 C O169.000	1	Withdrawn
AF2-391	961002	AF2-391 BAT 69.000	1	Withdrawn
AF2-393	961021	AF2-393 O1138.00	1	Withdrawn
AF2-394	961031	AF2-394 O1138.00	1	Withdrawn
AG1-003	961631	AG1-003 765.00	1	Withdrawn
AG1-004	961641	AG1-004 765.00	1	Withdrawn
AG1-005	961651	AG1-005 O1138.00	1	Withdrawn
AG1-120	962711	AG1-120 O1138.00	1	Withdrawn
AG1-218	963661	AG1-218 O1345.00	1	Withdrawn
AG1-222	963701	AG1-222 138.00	1	Withdrawn
AG1-298	964361	AG1-298 O1345.00	1	Withdrawn
AG1-319	964561	AG1-319 138.00	1	Withdrawn
AG1-401	965361	AG1-401 C 345.00	1	Withdrawn
AG1-403	965381	AG1-403 C 345.00	1	Withdrawn
AG1-434	965661	AG1-434 C O1345.00	1	Withdrawn
AG1-435	965671	AG1-435 C O1138.00	1	Withdrawn
AG1-522	966531	AG1-522 C 765.00	1	Withdrawn
AG1-523	966541	AG1-523 C 765.00	1	Withdrawn
AG1-524	966551	AG1-524 C 765.00	1	Withdrawn
AG1-525	966561	AG1-525 C 765.00	1	Withdrawn
AG1-562	966911	AG1-562 C O1345.00	1	Withdrawn

A.7 PJM Prior Queued Generation Projects

Table A-7: PJM Generation Projects in AE1 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AD2-100	IL	Christian	ComEd	Kincaid-Pana	Solar	210	210
AD2-131	IL	Christian	ComEd	Kincaid-Pana	Solar	50	50
AE1-143	KY	Marion	EKPC	Marion County 161 kV	Solar	96	96
AE1-170	MI	Cass	AEP	Kenzie Creek-Colby 138 kV	Solar	150	150

Table A-8: PJM Generation Projects in AE2 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AE1-113	IL	Woodford	ComEd	Mole Creek 345 kV	Wind	300	300
AE1-146	OH	Hancock	AEP	Ebersole #2-Fostoria Central 138 kV	Solar	120	120
AE1-163	IL	Woodford	ComEd	Powerton-Goodings Grove 345 kV	Wind	350	350
AE1-166	IL	Kankakee	ComEd	Loretto-Wilton & Braidwood-Davis Creek	Solar	150	150
AE1-205	IL	Livingston	ComEd	McLean 345 kV	Solar	200	200
AE1-207	IN	Grant	AEP	Mississinewa-Gaston 138 kV	Solar	160	160
AE1-208	IN	Delaware	AEP	Delaware-Van Buren 138 kV	Solar	130	130
AE1-209	IN	Randolph	AEP	Desoto 345 kV	Wind	100	100
AE1-210	IN	Randolph	AEP	Desoto 345 kV	Wind	100	100
AE2-035	IL	Stephenson	ComEd	Lena 138 kV	Solar	50	50
AE2-045	IN	Lake	AEP	Olive-Reynolds 345 kV	Solar	200	200
AE2-072	OH	Putnam	AEP	East Leipsic-Richland 138 kV	Solar	150	150
AE2-089	IN	Jay	AEP	Pennville-Adams 138 kV	Solar	155	155
AE2-152	IL	Kankakee	ComEd	Wilton Center-Loretto	Solar	150	150
AE2-176	OH	Erie	ATSI	Groton 138 kV Solar	Solar	125	125
AE2-194	OH	Columbiana	ATSI	Congress-Toronto 138 kV	Solar	145	145
AE2-220	IN	Randolph	AEP	Losantville - HEADWTR CS 345 kV	Solar	125	125
AE2-221	OH	Clinton	Dayton	Clinton-Stuart 345 kV	Solar	300	300
AE2-236	IN	Whitley	AEP	Columbia-Northeast 138 kV	Solar	55	55
AE2-255	IL	Woodford	ComEd	Molecreek 345 kV	Wind	100	400

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AE2-276	IN	Sullivan	AEP	Sullivan 345kV	Storage	50	50
AE2-281	IL	Woodford	ComEd	Powerton-Goodings Grove	Wind	50	400
AE2-282	OH	Fulton	ATSI	East Fayette 138 kV	Solar	67	67
AE2-299	PA	Erie	PENELEC	Erie East 230 kV	Storage	160	160
AE2-323	IN	Elkhart	AEP	Twin Branch-Guardian 138 kV	Solar	100	100

Table A-9: PJM Generation Projects in AF1 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AD2-047	IL	Kankakee	ComEd	Davis Creek 138 kV	Wind	200	200
AE2-169	IN	Delaware	AEP	Delaware-Van Buren 138 kV	Solar	33	163
AF1-051	OH	Gallia	AEP	Gavin 765 kV	Coal	11	1360
AF1-071	OH	Preble	AEP	College Corner 138 kV	Solar	18	98
AF1-084	MI	Van Buren	AEP	East Hartford-Murch 69 kV	Solar	85	85
AF1-090	IL	Christian	ComEd	Kincaid-Pana	Wind	200	200
AF1-092	IN	Huntington	AEP	Huntington Jct. 138 kV	Solar; Storage	150	150
AF1-118	IN	Wells	AEP	Sorenson-Desoto 345 kV	Solar; Storage	350	350
AF1-119	IN	Blackford	AEP	Keystone-Desoto 345 kV	Solar; Storage	200	200
AF1-158	IN	St. Joseph	AEP	Edison-Gravel Pit 138 kV	Solar; Storage	150	150
AF1-202	IN	Blackford	AEP	Keystone-Desoto 345 kV	Wind	200	200
AF1-206	OH	Fulton	ATSI	East Fayette 138 kV	Solar	199	199
AF1-207	IN	White	AEP	Reynolds–Olive #1 345 kV	Solar	180	180
AF1-215	IN	Starke	AEP	Reynolds-Olive 345 kV	Solar	300	300
AF1-223	IN	Blackford	AEP	Keystone-Desoto 345 kV	Solar	150	150
AF1-322	IN	White	AEP	Meadow Lake 345 kV	Solar	200	200

Table A-10: PJM Generation Projects in AF2 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AF2-014	OH	Van Wert	AEP	Maddox Creek 345 kV	Solar	150	150
AF2-027	IL	Lake	ComEd	Zion Energy Center 345 kV	Storage	50	635
AF2-031	IL	Cook	ComEd	Calumet	Storage	20	347
AF2-032	IL	Christian	ComEd	Kincaid 345 kV	Solar; Storage	20	1132
AF2-078	IN	White	AEP	Reynolds-Olive #1 345 kV	Solar; Storage	200	200
AF2-083	MI	Cass	AEP	Kenzie Creek-Stone Lake 69 kV	Solar	150	150
AF2-132	IN	Pulaski	AEP	Reynolds-Olive #1 345 kV	Solar	300	300
AF2-133	IN	Pulaski	AEP	Reynolds-Olive #2 345 kV	Solar	300	300
AF2-134	IN	Starke	AEP	Reynolds-Olive #2 345 kV	Solar	100	400
AF2-205	IN	Pulaski	AEP	Olive-Reynolds #2 345 kV	Solar	200	200
AF2-224	IN	Allen	AEP	Allen 345 kV	Solar	100	100
AF2-252	IL	McLean	ComEd	Blue Mound 345 kV	Storage	50	248
AF2-352	IL	McLean	ComEd	Blue Mound 345 kV	Storage	50	248
AF2-359	IN	LaPorte	AEP	Olive-University Park 345 kV	Solar	125	125
AF2-366	IL	Adams	ComEd	Crego Rd 138 kV	Solar	94.9	94.9
AF2-375	OH	Hancock	AEP	Ebersole-Fostoria 138 kV	Solar	129.6	129.6
AF2-389	MI	Cass	AEP	Pokagon-Corey 69 kV	Solar	50	50
AF2-408	IN	Madison	AEP	Fall Creek 138 kV	Storage	80	80

Table A-11: PJM Generation Projects in AG1 Cluster

PJM Project #	State	County	TO	Point of Interconnection	Fuel	MW Energy	MFO
AG1-047	IN	Jay	AEP	Jay 138 kV	Solar	100	100
AG1-125	OH	Madison	AEP	Marysville-Flatlick 765 kV	Solar	400	400
AG1-126	OH	Madison	AEP	Marysville-Flatlick 765 kV	Solar	400	400
AG1-237	IN	N/A	AEP	Dequine-Eugene 345 kV	Wind	200	200
AG1-302	IN	Pulaski	AEP	Olive-Reynolds #1 345 kV	Solar	300	300
AG1-349	IN	Pulaski	AEP	Olive-Reynolds #2 345 kV	Solar	260	260
AG1-414	IN	Grant	AEP	Mississinewa 138 kV	Solar; Storage	75	75
AG1-500	OH	Lorain	ATSI	Beaver 345 kV	Natural Gas	406.4	784.6
AG1-555	IN	Tippecance	AEP	Dequine 345 kV	Solar; Storage	120	120

A.8 PJM Market as PJM Projects Sink

Table A-12: PJM Market as PJM Projects Sink

Area #	Area Name	Area #	Area Name
201	AP	229	PPL
202	ATSI	230	PECO
205	AEP	231	PSE&G
206	OVEC	232	BGE
209	DAY	233	PEPCO
212	DEO&K	234	AE
215	DLCO	235	DP&L
222	CE	236	UGI
225	PJM	237	RECO
226	PENELEC	320	EKPC
227	METED	345	DVP
228	JCP&L	720	PJM Prior

A.9 MISO North for Power Balance

Table A-13. MISO North for Power Balance

Area #	Area Name
207	HE
208	DEI
210	SIGE
216	IPL
217	NIPS
218	METC
219	ITC
295	WEC
296	MIUP
314	BREC
315	HMPL
333	CWLD
356	AMMO
357	AMIL
360	CWLP
361	SIPC
362	GLH

Area #	Area Name
600	Xcel
608	MP
613	SMMPA
615	GRE
620	OTP
627	ALTW
633	MPW
635	MEC
661	MDU
663	BEPC-MISO
680	DPC
694	ALTE
696	WPS
697	MGE
698	UPPC
701	Classic Prior

A.10 Contingency Files used in Steady-State Analysis

Table A-14: List of Contingencies used in the Steady-State Analysis

Contingency File Name	Description
Automatic single element contingencies	Single element outages at buses 60 kV and above in the study region
MISO21_2026_SUM_TA_Central_P1.con	Specified category P1 contingencies in MISO Central Area
MISO21_2026_SUM_TA_Central_P1_P2_P4_P5_P7.con	Specified category P1, P2, P4, P5, P7 contingencies in MISO Central
MISO21_2026_SUM_TA_ITC-METC_P1_P2_P4_P5_P7(2025-03-18).con	Specified category P1, P2, P4, P5, P7 contingencies in MISO Michigan
RTEP-2021_2026SUM_Sorted_Single_fixed.con	Specified single contingencies in PJM
RTEP-2021_2026SUM_Sorted_P2-1_fixed.con	Specified P2-1 contingencies in PJM
RTEP-2021_2026SUM_Sorted_Line_FB_fixed.con	Specified stuck breaker contingencies in PJM
RTEP-2021_2026SUM_Sorted_Bus_fixed.con	Specified bus contingencies in PJM
RTEP-2021_2026SUM_Sorted_Tower_fixed.con	Specified common tower contingencies in PJM
2017 P1 LG&E-KU.con	Specified category P1 contingencies in LG&E, KU
2017 P2 LG&E-KU.con	Specified category P2 contingencies in LG&E, KU
2017 P4 LG&E-KU.con	Specified category P4 contingencies in LG&E, KU
2017 P7 LG&E-KU.con	Specified category P7 contingencies in LG&E, KU
2021SUM_TA_TVA_s21_P1_MISO.con	Specified category P1 contingencies in TVA
s21_P2_MISO.con	Specified category P2 contingencies in TVA
s21_P4P5_MISO.con	Specified category P4, P5 contingencies in TVA
s21_P7_MISO.con	Specified category P7 contingencies in TVA
AECI-AMMO.con	Specified contingencies between AECI and Ameren
AECI_Neighboring_Impacts_2020.con	Specified contingencies in AECI
External_P1s.con	Specified category P1 contingencies in external system
External_P1-P7.con	Specified category P1-P7 contingencies in external system

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Appendix

B

Stage-1 MISO Steady State Thermal and Voltage Analysis Results

B.1 Stage-1 Summer Peak (SPK) with 2000 MW IR MISO Results

B.1.1 Stage-1 MISO Detailed Constraints in Summer Peak IR

Table B-1. Stage-1 SPK with 2000 MW IR System Intact Thermal Constraints

Table B-2. Stage-1 SPK with 2000 MW IR System Intact Voltage Constraints

Table B-3. Stage-1 SPK with 2000 MW IR Category P1 Thermal Constraints

Table B-4. Stage-1 SPK with 2000 MW IR Category P1 Voltage Constraints

Table B-5. Stage-1 SPK with 2000 MW IR Category P2-P7 Thermal Constraints

Table B-6. Stage-1 SPK with 2000 MW IR Category P2-P7 Voltage Constraints

Table B-7. Stage-1 SPK with 2000 MW IR Contingencies Causing Voltage Collapses

CEII Redacted

B.1.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Peak IR

Table B-8. Stage-1 MISO Worst Thermal Constraints in SPK with 2000 MW IR

Table B-9. Stage-1 MISO Worst Voltage Constraints in SPK with 2000 MW IR

CEII Redacted

B.2 Stage-1 Summer Peak (SPK) with 2000 MW WR MISO Results

B.2.1 Stage-1 MISO Detailed Constraints in Summer Peak WR

Table B-10. Stage-1 SPK with 2000 MW WR System Intact Thermal Constraints

Table B-11. Stage-1 SPK with 2000 MW WR System Intact Voltage Constraints

Table B-12. Stage-1 SPK with 2000 MW WR Category P1 Thermal Constraints

Table B-13. Stage-1 SPK with 2000 MW WR Category P1 Voltage Constraints

Table B-14. Stage-1 SPK with 2000 MW WR Category P2-P7 Thermal Constraints

Table B-15. Stage-1 SPK with 2000 MW WR Category P2-P7 Voltage Constraints

Table B-16. Stage-1 SPK with 2000 MW WR Contingencies Causing Voltage Collapses

CEII Redacted

B.2.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Peak WR

Table B-17. Stage-1 MISO Worst Thermal Constraints in SPK with 2000 MW WR

Table B-18. Stage-1 MISO Worst Voltage Constraints in SPK with 2000 MW WR

CEII Redacted

B.3 Stage-1 Summer Shoulder (SH) Discharging with 2000 MW IR MISO Results

B.3.1 Stage-1 MISO Detailed Constraints in Summer Shoulder Discharging IR

Table B-19. Stage-1 SH Discharging with 2000 MW IR System Intact Thermal Constraints

Table B-20. Stage-1 SH Discharging with 2000 MW IR System Intact Voltage Constraints

Table B-21. Stage-1 SH Discharging with 2000 MW IR Category P1 Thermal Constraints

Table B-22. Stage-1 SH Discharging with 2000 MW IR Category P1 Voltage Constraints

Table B-23. Stage-1 SH Discharging with 2000 MW IR Category P2-P7 Thermal Constraints

Table B-24. Stage-1 SH Discharging with 2000 MW IR Category P2-P7 Voltage Constraints

CEII Redacted

B.3.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Shoulder Discharging IR

Table B-25. Stage-1 MISO Worst Thermal Constraints in SH Discharging with 2000 MW IR

Table B-26. Stage-1 MISO Worst Voltage Constraints in SH Discharging with 2000 MW IR

CEII Redacted

B.4 Stage-1 Summer Shoulder (SH) Discharging with 2000 MW WR MISO Results

B.4.1 Stage-1 MISO Detailed Constraints in Summer Shoulder Discharging WR

Table B-27. Stage-1 SH Discharging with 2000 MW WR System Intact Thermal Constraints

Table B-28. Stage-1 SH Discharging with 2000 MW WR System Intact Voltage Constraints

Table B-29. Stage-1 SH Discharging with 2000 MW WR Category P1 Thermal Constraints

Table B-30. Stage-1 SH Discharging with 2000 MW WR Category P1 Voltage Constraints

Table B-31. Stage-1 SH Discharging with 2000 MW WR Category P2-P7 Thermal Constraints

Table B-32. Stage-1 SH Discharging with 2000 MW WR Category P2-P7 Voltage Constraints

CEII Redacted

B.4.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Shoulder Discharging WR

Table B-33. Stage-1 MISO Worst Thermal Constraints in SH Discharging with 2000 MW WR

Table B-34. Stage-1 MISO Worst Voltage Constraints in SH Discharging with 2000 MW WR

CEII Redacted

B.5 Stage-1 Summer Shoulder (SH) Charging with 2000 MW IR MISO Results

B.5.1 Stage-1 MISO Detailed Constraints in Summer Shoulder Charging IR

Table B-35. Stage-1 SH Charging with 2000 MW IR System Intact Thermal Constraints

Table B-36. Stage-1 SH Charging with 2000 MW IR System Intact Voltage Constraints

Table B-37. Stage-1 SH Charging with 2000 MW IR Category P1 Thermal Constraints

Table B-38. Stage-1 SH Charging with 2000 MW IR Category P1 Voltage Constraints

Table B-39. Stage-1 SH Charging with 2000 MW IR Category P2-P7 Thermal Constraints

Table B-40. Stage-1 SH Charging with 2000 MW IR Category P2-P7 Voltage Constraints

CEII Redacted

B.5.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Shoulder Charging IR

Table B-41. Stage-1 MISO Worst Thermal Constraints in SH Charging with 2000 MW IR

Table B-42. Stage-1 MISO Worst Voltage Constraints in SH Charging with 2000 MW IR

CEII Redacted

B.6 Stage-1 Summer Shoulder (SH) Charging with 2000 MW WR MISO Results

B.6.1 Stage-1 MISO Detailed Constraints in Summer Shoulder Charging WR

Table B-43. Stage-1 SH Charging with 2000 MW WR System Intact Thermal Constraints

Table B-44. Stage-1 SH Charging with 2000 MW WR System Intact Voltage Constraints

Table B-45. Stage-1 SH Charging with 2000 MW WR Category P1 Thermal Constraints

Table B-46. Stage-1 SH Charging with 2000 MW WR Category P1 Voltage Constraints

Table B-47. Stage-1 SH Charging with 2000 MW WR Category P2-P7 Thermal Constraints

Table B-48. Stage-1 SH Charging with 2000 MW WR Category P2-P7 Voltage Constraints

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B.6.2 Stage-1 MISO Worst Thermal and Voltage Constraints in Summer Shoulder Charging WR

Table B-49. Stage-1 MISO Worst Thermal Constraints in SH Charging with 2000 MW WR

Table B-50. Stage-1 MISO Worst Voltage Constraints in SH Charging with 2000 MW WR

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B.7 Stage-1 Worst Voltage Constraints in the Combined Scenarios

Table B-51. Stage-1 Worst Voltage Constraints in the Combined Scenarios

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Appendix
C

Stage-1 NIPSCO LPC Thermal Results

C.1 Stage-1 Summer Peak (SPK) with 2000 MW IR NIPSCO LPC Results

Table C-1. Stage-1 SPK with 2000 MW IR System Intact NIPSCO LPC Thermal Constraints

Table C-2. Stage-1 SPK with 2000 MW IR Category P1 NIPSCO LPC Thermal Constraints

Table C-3. Stage-1 SPK with 2000 MW IR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-4. Stage-1 SPK with 2000 MW IR NIPSCO LPC Worst Thermal Constraints

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Stage-1 NIPSCO LPC Thermal Results

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C.2 Stage-1 Summer Peak (SPK) with 2000 MW WR NIPSCO LPC Results

Table C-5. Stage-1 SPK with 2000 MW WR System Intact NIPSCO LPC Thermal Constraints

Table C-6. Stage-1 SPK with 2000 MW WR Category P1 NIPSCO LPC Thermal Constraints

Table C-7. Stage-1 SPK with 2000 MW WR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-8. Stage-1 SPK with 2000 MW WR NIPSCO LPC Worst Thermal Constraints

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Stage-1 NIPSCO LPC Thermal Results

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C.3 Stage-1 Summer Shoulder (SH) Discharging with 2000 MW IR NIPSCO LPC Results

Table C-9. Stage-1 SH Discharging with 2000 MW IR System Intact NIPSCO LPC Thermal Constraints

Table C-10. Stage-1 SH Discharging with 2000 MW IR Category P1 NIPSCO LPC Thermal Constraints

Table C-11. Stage-1 SH Discharging with 2000 MW IR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-12. Stage-1 SH Discharging with 2000 MW IR NIPSCO LPC Worst Thermal Constraints

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C.4 Stage-1 Summer Shoulder (SH) Discharging with 2000 MW WR NIPSCO LPC Results

Table C-13. Stage-1 SH Discharging with 2000 MW WR System Intact NIPSCO LPC Thermal Constraints

Table C-14. Stage-1 SH Discharging with 2000 MW WR Category P1 NIPSCO LPC Thermal Constraints

Table C-15. Stage-1 SH Discharging with 2000 MW WR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-16. Stage-1 SH Discharging with 2000 MW WR NIPSCO LPC Worst Thermal Constraints

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Stage-1 NIPSCO LPC Thermal Results

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C.5 Stage-1 Summer Shoulder (SH) Charging with 2000 MW IR NIPSCO LPC Results

Table C-17. Stage-1 SH Charging with 2000 MW IR System Intact NIPSCO LPC Thermal Constraints

Table C-18. Stage-1 SH Charging with 2000 MW IR Category P1 NIPSCO LPC Thermal Constraints

Table C-19. Stage-1 SH Charging with 2000 MW IR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-20. Stage-1 SH Charging with 2000 MW IR NIPSCO LPC Worst Thermal Constraints

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Stage-1 NIPSCO LPC Thermal Results

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C.6 Stage-1 Summer Shoulder (SH) Charging with 2000 MW WR NIPSCO LPC Results

Table C-21. Stage-1 SH Charging with 2000 MW WR System Intact NIPSCO LPC Thermal Constraints

Table C-22. Stage-1 SH Charging with 2000 MW WR Category P1 NIPSCO LPC Thermal Constraints

Table C-23. Stage-1 SH Charging with 2000 MW WR Category P2-P7 NIPSCO LPC Thermal Constraints

Table C-24. Stage-1 SH Charging with 2000 MW WR NIPSCO LPC Worst Thermal Constraints

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Stage-1 NIPSCO LPC Thermal Results

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Appendix D

Stage-2 MISO Steady State Thermal and Voltage Analysis Results

D.1 Stage-2 MISO Constraints in Summer Peak IR

Table D-1. Stage-2 SPK with 2000 MW IR System Intact Thermal Constraints

Table D-2. Stage-2 SPK with 2000 MW IR System Intact Voltage Constraints

Table D-3. Stage-2 SPK with 2000 MW IR Category P1 Thermal Constraints

Table D-4. Stage-2 SPK with 2000 MW IR Category P1 Voltage Constraints

Table D-5. Stage-2 SPK with 2000 MW IR Category P2-P7 Thermal Constraints

Table D-6. Stage-2 SPK with 2000 MW IR Category P2-P7 Voltage Constraints

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D.2 Stage-2 MISO Constraints in Summer Peak WR

Table D-7. Stage-2 SPK with 2000 MW WR System Intact Thermal Constraints

Table D-8. Stage-2 SPK with 2000 MW WR System Intact Voltage Constraints

Table D-9. Stage-2 SPK with 2000 MW WR Category P1 Thermal Constraints

Table D-10. Stage-2 SPK with 2000 MW WR Category P1 Voltage Constraints

Table D-11. Stage-2 SPK with 2000 MW WR Category P2-P7 Thermal Constraints

Table D-12. Stage-2 SPK with 2000 MW WR Category P2-P7 Voltage Constraints

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Appendix
E

Stage-2 NIPSCO LPC Thermal Results

E.1 Stage-2 Summer Peak (SPK) with 2000 MW IR NIPSCO LPC Results

Table E-1. Stage-2 SPK with 2000 MW IR System Intact NIPSCO LPC Thermal Constraints

Table E-2. Stage-2 SPK with 2000 MW IR Category P1 NIPSCO LPC Thermal Constraints

Table E-3. Stage-2 SPK with 2000 MW IR Category P2-P7 NIPSCO LPC Thermal Constraints

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Stage-2 NIPSCO LPC Thermal Results

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E.2 Stage-2 Summer Peak (SPK) with 2000 MW WR NIPSCO LPC Results

Table E-4. Stage-2 SPK with 2000 MW WR System Intact NIPSCO LPC Thermal Constraints

Table E-5. Stage-2 SPK with 2000 MW WR Category P1 NIPSCO LPC Thermal Constraints

Table E-6. Stage-2 SPK with 2000 MW WR Category P2-P7 NIPSCO LPC Thermal Constraints

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Stage-2 NIPSCO LPC Thermal Results

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Appendix F

Stability Analysis Results

F.1 Summer Peak IR Stability Results

Stability simulation was performed in the 2026 summer peak (SPK) with 2000 MW Injection Right (IR) stability model.

F.1.1 SPK with 2000 MW IR Stability Summary

Summer peak with 2000 MW IR stability study results are summarized in Table F-1.

Table F-1: Summer Peak with 2000 MW IR Stability Analysis Results Summary

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F.1.2 SPK with 2000 MW IR Stability Plots

Plots of stability simulations for summer peak with 2000 MW IR study case are in separate files which are listed below:

AppendixF1-2_SPK IR_PJM-TC1_Study_Plots.zip

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F.2 Summer Peak WR Stability Results

Stability simulation was performed in the 2026 summer peak (SPK) with 2000 MW Withdrawal Right (WR) stability model.

F.2.1 SPK with 2000 MW WR Stability Summary

Summer peak with 2000 MW WR stability study results are summarized in Table F-2.

Table F-2: Summer Peak with 2000 MW WR Stability Analysis Results Summary

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F.2.2 SPK with 2000 MW WR Stability Plots

Plots of stability simulations for summer peak with 2000 MW WR study case are in separate files which are listed below:

AppendixF2-2_SPK WR_PJM-TC1_Study_Plots.zip

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F.3 Summer Shoulder Discharging IR Stability Results

Stability simulation was performed in the 2026 summer shoulder (SH) discharging with 2000 MW Injection Right (IR) stability model.

F.3.1 SH Discharging with 2000 MW IR Stability Summary

Summer shoulder discharging with 2000 MW IR stability study results are summarized in Table F-3.

Table F-3: Summer Shoulder Discharging with 2000 MW IR Stability Analysis Results Summary

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F.3.2 SH Discharging with 2000 MW IR Stability Plots

Plots of stability simulations for summer shoulder discharging with 2000 MW IR study case are in separate files which are listed below:

AppendixF3-2_SH-Discharge IR_PJM-TC1_Study_Plots.zip

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F.4 Summer Shoulder Discharging WR Stability Results

Stability simulation was performed in the 2026 summer shoulder (SH) discharging with 2000 MW Withdrawal Right (WR) stability model.

F.4.1 SH Discharging with 2000 MW WR Stability Summary

Summer shoulder discharging with 2000 MW WR stability study results are summarized in Table F-4.

Table F-4: Summer Shoulder Discharging with 2000 MW WR Stability Analysis Results Summary

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F.4.2 SH Discharging with 2000 MW WR Stability Plots

Plots of stability simulations for summer shoulder discharging with 2000 MW WR study case are in separate files which are listed below:

AppendixF4-2_SH-Discharge WR_PJM-TC1_Study_Plots.zip

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F.5 Summer Shoulder Charging IR Stability Results

Stability simulation was performed in the 2026 summer shoulder (SH) charging with 2000 MW Injection Right (IR) stability model.

F.5.1 SH Charging with 2000 MW IR Stability Summary

Summer shoulder charging with 2000 MW IR stability study results are summarized in Table F-5.

Table F-5: Summer Shoulder Charging with 2000 MW IR Stability Analysis Results Summary

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F.5.2 SH Charging with 2000 MW IR Stability Plots

Plots of stability simulations for summer shoulder charging with 2000 MW IR study case are in separate files which are listed below:

AppendixF5-2_SH-Charge IR_PJM-TC1_Study_Plots.zip

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F.6 Summer Shoulder Charging WR Stability Results

Stability simulation was performed in the 2026 summer shoulder (SH) charging with 2000 MW Withdrawal Right (WR) stability model.

F.6.1 SH Charging with 2000 MW WR Stability Summary

Summer shoulder charging with 2000 MW WR stability study results are summarized in Table F-6.

Table F-6: Summer Shoulder Charging with 2000 MW WR Stability Analysis Results Summary

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F.6.2 SH Charging with 2000 MW WR Stability Plots

Plots of stability simulations for summer shoulder charging with 2000 MW WR study case are in separate files which are listed below:

AppendixF6-2_SH-Charge WR_PJM-TC1_Study_Plots.zip

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Appendix
G

Cost Allocation Results

G.1 Distribution Factor (DF), Voltage Impact, and MW Contribution Results for Cost Allocation

Table G-1: Distribution Factor and MW Contribution on Constraints for MISO Affected System Thermal NU Cost Allocation

Table G-2: Voltage Impact on MISO Voltage NUs Cost Allocation

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G.2 Cost Allocation Details

Table G-3: MISO Affected System Network Upgrades Cost Allocation

Table G-3: MISO Affected System Network Upgrades Cost Allocation

Monitored Element	English Name	Owner	Cost	AE1-114	AE1-172	AE2-173	AE2-223	AE2-261	AE2-308	AE2-321	AE2-325	AE2-341	AF1-030	AF1-088
249505 08CAYUGA 345 249516 08NUCOR 345 1	Cayuga - Nucor 345 kV	DEI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255204 17REYNOLDS 765 255205 17REYNOLDS 345 3	Reynold 765/345 kv xfmr	NIPSCO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 243412 05STURGI 69.0 99	Sturgis - Howe 69 kV	NIPSCO AEP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 255345 17N_LAGRANGE69.0 1	Howe - North Lagrange 69 kV	NIPSCO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255339 17LAGRANGE 69.0 255345 17N_LAGRANGE69.0 99	North Lagrange - Lagrange 69 kV	NIPSCO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
348149 4MORO 138 348791 4LACLEDE NTP 138 1	Moro - Laclede NTP 138 kV	AMIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
250955 08WVRICH 69.0 255353 17ROCHSTR_TP69.0 1	Wvrich - Rochester TP 69 kV	DEI NIPSCO	$1,500,000	$5,222	$9,327	$8,686	$4,065	$25,339	$0	$24,435	$19,243	$38,135	$25,424	$94,633
255303 17ARGOS 69.0 255349 17PLYMOUTH 69.0 99	Argos - Plymouth 69 kV	NIPSCO	$12,654,948	$42,527	$76,004	$69,900	$32,713	$250,802	$0	$199,216	$158,114	$312,804	$208,536	$780,553
255303 17ARGOS 69.0 255353 17ROCHSTR_TP69.0 99	Argos - Rochester TP 69 kV	NIPSCO	$4,049,583	$14,098	$25,180	$23,451	$10,975	$68,408	$0	$65,968	$51,951	$102,955	$68,637	$255,481
Install 144 MVAR cap bank at Gallagher substation	Install 144 MVAR cap bank at Gallagher substation	DEI	$3,000,000	$8,357	$8,357	$16,713	$8,357	$125,348	$0	$25,070	$8,357	$41,783	$25,070	$614,206
Install 28.8 MVAR cap bank at Shoals substation	Install 28.8 MVAR cap bank at Shoals substation	DEI	$3,000,000	$6,329	$6,329	$18,987	$6,329	$139,241	$0	$25,316	$6,329	$37,975	$25,316	$655,063
Install 28.8 MVAR cap bank at Avon East substation	Install 28.8 MVAR cap bank at Avon East substation	DEI	$3,000,000	$5,660	$11,321	$16,981	$11,321	$124,528	$0	$28,302	$5,660	$33,962	$22,642	$676,415
Total Cost Per Project for each Project	**Total Cost Per Project**		**$27,204,531**	**$82,193**	**$136,517**	**$154,719**	**$73,760**	**$733,666**	**$0**	**$368,306**	**$249,655**	**$567,614**	**$375,624**	**$3,076,352**

Monitored Element	AF2-008	AF1-161	AF1-176	AF1-204	AF1-233	AF1-280	AF1-296	AF2-041	AF2-068	AF2-069	AF2-095	AF2-111	AF2-126	AF2-142	AF2-143	AF2-173	AF2-177
249505 08CAYUGA 345 249516 08NUCOR 345 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255204 17REYNOLDS 765 255205 17REYNOLDS 345 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 243412 05STURGI 69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 255345 17N_LAGRANGE69.0 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255339 17LAGRANGE 69.0 255345 17N_LAGRANGE69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
348149 4MORO 138 348791 4LACLEDE NTP 138 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
250955 08WVRICH 69.0 255353 17ROCHSTR_TP69.0 1	$94,633	$18,432	$115,254	$0	$0	$43,503	$5,847	$68,644	$0	$268	$41,898	$0	$169	$39,619	$37,924	$0	$0
255303 17ARGOS 69.0 255349 17PLYMOUTH 69.0 99	$780,553	$151,451	$947,149	$3,244	$0	$354,162	$47,531	$562,697	$0	$2,182	$343,909	$0	$1,398	$323,289	$309,309	$0	$0
255303 17ARGOS 69.0 255353 17ROCHSTR_TP69.0 99	$255,481	$49,762	$311,154	$0	$0	$117,445	$15,784	$185,319	$0	$724	$113,113	$0	$458	$106,959	$102,383	$0	$0
Install 144 MVAR cap bank at Gallagher substation	$614,206	$8,357	$50,139	$25,070	$0	$58,496	$8,357	$83,565	$8,357	$0	$33,426	$0	$0	$41,783	$41,783	$8,357	$0
Install 28.8 MVAR cap bank at Shoals substation	$655,063	$6,329	$44,304	$18,987	$0	$56,962	$6,329	$88,608	$0	$0	$31,646	$0	$0	$37,975	$44,304	$0	$0
Install 28.8 MVAR cap bank at Avon East substation	$676,415	$5,660	$28,302	$22,642	$0	$50,943	$11,321	$73,585	$0	$0	$33,962	$0	$0	$39,623	$39,623	$0	$0
Total Cost Per Project for each Project	**$3,076,352**	**$239,991**	**$1,496,302**	**$69,943**	**$0**	**$681,511**	**$95,168**	**$1,062,419**	**$8,357**	**$3,175**	**$597,955**	**$0**	**$2,025**	**$589,247**	**$575,325**	**$8,357**	**$0**

Monitored Element	AF2-182	AF2-199	AF2-200	AF2-225	AF2-226	AF2-307	AF2-319	AF2-335	AF2-349	AF2-350	AF2-388	AF2-392	AF2-396	AF2-407	AF2-441
249505 08CAYUGA 345 249516 08NUCOR 345 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255204 17REYNOLDS 765 255205 17REYNOLDS 345 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 243412 05STURGI 69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255331 17HOWE 69.0 255345 17N_LAGRANGE69.0 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
255339 17LAGRANGE 69.0 255345 17N_LAGRANGE69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
348149 4MORO 138 348791 4LACLEDE NTP 138 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
250955 08WVRICH 69.0 255353 17ROCHSTR_TP69.0 1	$65,254	$22,881	$45,763	$26,059	$13,347	$0	$13,347	$0	$71,610	$29,096	$0	$6,708	$74,859	$0	$64,407
255303 17ARGOS 69.0 255349 17PLYMOUTH 69.0 99	$531,242	$187,566	$375,132	$209,701	$108,928	$0	$108,928	$0	$583,668	$238,826	$0	$54,604	$615,123	$0	$526,582
255303 17ARGOS 69.0 255353 17ROCHSTR_TP69.0 99	$176,168	$61,773	$123,546	$70,353	$36,034	$0	$36,034	$0	$193,327	$78,551	$0	$18,109	$202,097	$0	$173,880
Install 144 MVAR cap bank at Gallagher substation	$83,565	$25,070	$58,496	$50,139	$16,713	$0	$16,713	$8,357	$83,565	$25,070	$8,357	$8,357	$33,426	$0	$50,139
Install 28.8 MVAR cap bank at Shoals substation	$88,608	$25,316	$56,962	$56,962	$12,658	$0	$12,658	$0	$88,608	$25,316	$0	$6,329	$25,316	$0	$50,633
Install 28.8 MVAR cap bank at Avon East substation	$73,585	$28,302	$50,943	$50,943	$16,981	$0	$16,981	$0	$73,585	$22,642	$11,321	$11,321	$22,642	$0	$45,283
Total Cost Per Project for each Project	**$1,018,422**	**$350,908**	**$710,842**	**$464,158**	**$204,662**	**$0**	**$204,662**	**$8,357**	**$1,094,362**	**$419,501**	**$19,677**	**$105,428**	**$973,463**	**$0**	**$910,924**

Monitored Element	AG1-118	AG1-127	AG1-226	AG1-236	AG1-297	AG1-320	AG1-341	AG1-354	AG1-367	AG1-374	AG1-375	AG1-410	AG1-411	AG1-433	AG1-436	AG1-447	AG1-460	AG1-462	AG1-471	AG1-526	AG1-553	Upgrade for
249505 08CAYUGA 345 249516 08NUCOR 345 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
255204 17REYNOLDS 765 255205 17REYNOLDS 345 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
255331 17HOWE 69.0 243412 05STURGI 69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
255331 17HOWE 69.0 255345 17N_LAGRANGE69.0 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
255339 17LAGRANGE 69.0 255345 17N_LAGRANGE69.0 99	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
348149 4MORO 138 348791 4LACLEDE NTP 138 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Thermal
250955 08WVRICH 69.0 255353 17ROCHSTR_TP69.0 1	$73,305	$23,103	$27,966	$3,094	$0	$0	$0	$0	$0	$47,881	$0	$0	$0	$0	$48,022	$21,130	$2,542	$48,983	$0	$0	$49,943	NIPSCO LPC
255303 17ARGOS 69.0 255349 17PLYMOUTH 69.0 99	$601,143	$188,346	$555,707	$28,133	$0	$0	$0	$0	$0	$387,947	$0	$0	$0	$0	$393,189	$173,003	$25,164	$398,082	$0	$0	$405,888	NIPSCO LPC
255303 17ARGOS 69.0 255353 17ROCHSTR_TP69.0 99	$197,903	$62,373	$75,500	$8,352	$0	$0	$0	$0	$0	$129,266	$0	$0	$0	$0	$129,647	$57,045	$6,864	$132,240	$0	$0	$134,833	NIPSCO LPC
Install 144 MVAR cap bank at Gallagher substation	$83,565	$25,070	$183,844	$16,713	$0	$0	$0	$0	$16,713	$108,635	$8,357	$16,713	$0	$0	$33,426	$16,713	$8,357	$75,209	$0	$0	$75,209	MISO Voltage
Install 28.8 MVAR cap bank at Shoals substation	$82,278	$25,316	$177,215	$12,658	$0	$0	$0	$0	$0	$113,924	$6,329	$6,329	$0	$0	$25,316	$12,658	$12,658	$75,949	$0	$0	$82,278	MISO Voltage
Install 28.8 MVAR cap bank at Avon East substation	$73,585	$22,642	$203,774	$16,981	$0	$5,660	$16,981	$16,981	$0	$107,547	$0	$0	$0	$0	$22,642	$11,321	$16,981	$67,925	$5,660	$0	$67,925	MISO Voltage
Total Cost Per Project for each Project	**$1,111,779**	**$346,850**	**$1,224,007**	**$85,931**	**$0**	**$5,660**	**$16,981**	**$16,981**	**$16,713**	**$895,200**	**$14,686**	**$23,042**	**$0**	**$0**	**$652,243**	**$291,870**	**$72,566**	**$798,388**	**$5,660**	**$0**	**$816,076**	

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Siemens Industry, Inc.
Siemens Power Technologies International
10900 Wayzata Boulevard
Minnetonka, Minnesota 55305 USA
Tel: +1 (317) 903-9803

Siting Board Post-Hearing 1-2:

Provide signed green cards or proof of service for all adjacent landowners that received notification that Barrelhead Solar intended to file an application to the Siting Board.

Response: Please see the Motion for Extension.

Witness: Legal

Siting Board Post-Hearing 1-3:

Provide the number of solar facilities that Birch Creek Energy Holdings, LLC or Birch Creek Development, LLC has constructed.

Response: Birch Creek Energy Holdings, LLC has 755.3 MWdc (15 projects) operational solar projects. 209.6 MWdc (5 projects) of solar projects are currently under construction (various stages).

Following the Siting Board Hearing, it was brought to the Developer's attention that a project within the portfolio had been impacted by a tornado. The solar project located in Illinois was directly affected by an EF2 tornado in March 2025. From the initial assessment, no injuries were reported, and over half of the site was re-energized within 3 weeks, with additional repairs following in the subsequent months.

Witness: Trudie Grattan

Siting Board Post-Hearing 1-4:

Provide the Virginia Tech Study and the Appraisal Study that was referenced by Richard Kirkland during his testimony at the February 17, 2026 hearing.

Response: Please see the attached studies referenced during the February 17, 2026 hearing, provided as Attachment PHDR 1-4.

Witness: Richard Kirkland

Do Utility-Scale Solar Projects Affect Nearby Residential Real Estate Markets?

by Erin Kiella, PhD, Jennifer Pitts, MAI, and Christopher Yost-Bremm, PhD

Abstract

Although public support exists for the development of green energy in the form of large-scale solar projects, specific proposed projects are occasionally met with local opposition. Homeowners in surrounding areas may express concern regarding negative impacts to their properties due to the construction and operation of a large-scale solar project. This research was intended to address the question of whether, in general, residential market areas proximate to a large-scale solar project should expect to see a drop or decline in property value. The market trend analyses of residential homes in markets proximate to three large-scale solar projects did not provide any evidence of a negative impact on sale prices, days on market, or sale price–to–list price ratio. Our findings do not indicate a negative impact due to proximity to a large-scale solar project. The market trends analyses presented here, in combination with the findings from published literature, provide evidence that market demand exists at competitive prices for residential properties proximate to large-scale solar facilities. These findings cannot be generalized or assumed to apply to every market or solar project, as any potential impacts depend on many factors particular to individual projects and locations. Individual, market-specific analysis must be conducted to support any estimate of diminution in value.*

What Is a Typical Utility-Scale Solar Project?

While no uniform definition for a utility-scale solar project exists, the industry tends to use two defining features for classification: size and energy use. The Solar Energy Industries Association (SEIA) defines a utility-scale solar project as one generating over one megawatt (MW) of solar energy. The National Renewable Energy Laboratory defines a project as being utility-scale if it generates more than five MWs of solar energy. Utility-scale projects also typically sell electricity directly to the grid as opposed to supplying electricity to an individual facility.

Developers of utility-scale solar projects typically plan for at least 100 MW of electricity production, which requires approximately 800 to 1,000 acres of land. Leasing land for these projects is preferred by developers. In some cases, developers purchase the land where the substation or operation and management buildings are located. Land with access to transmission lines and with a flat to slightly sloping topography and ideally a south-facing slope is preferred.[1]

Twenty- to thirty-year leases with a fixed-rate

*This study was commissioned and made possible with funding from Conservative Texans for Energy Innovation in partnership with the Advanced Power Alliance and the Solar Energy Industries Association. Funding was not contingent on the results of the study, and the funding sources played no role in the research.

1. Lease structures and ideal solar project characteristics were summarized from leases used by the market and from discussions with market experts.

lease structure are typical. Leases have two lease rate structures based on whether the project is in the development phase or the operational phase. Development phases typically last three to five years, while the operational phase lasts twenty to thirty years. The lease rates for the operational phase are both inflation-adjusted and allocated at the start of each decade following the initiation of the lease (i.e., Rate 1 for Years 1–10, Rate 2 for Years 11–20, and Rate 3 for Years 21–30). Leases also typically include options to extend the lease, with a rate identified for each extension. In addition to standard lease rates, transmission and access easements are included for the development phase. One-time payments for these easements are based on land usage (i.e., the length of road developed or underground cable installed). The lease includes a waiver stating that the landlord waives their right to ingress and egress to, on, and over that portion of their property.

The tenant typically has the superior rights to use of the land. They have the right to transfer, convey, sublease, or assign the lease or any interest without the consent of the landlord. The landlord also has the right to assign or transfer their interest in the lease or the underlying real property without the consent of the tenant. Typically, the tenant has no water rights unless otherwise agreed upon. If the landlord experiences any increase in ad valorem property taxes assessed for the property after the operation date of the solar project, the tenant typically reimburses the landlord.

It is not uncommon for several projects to exist at a single site or for one project to extend over multiple properties. In these instances, each project has a separate lease with the landlord. The leases may have the same terms but exist for each individual project.

Texas state law requires the decommissioning process to be bonded in a manner acceptable to the landlord. Doing so eliminates the potential for a landowner to be left with decommissioned solar panels on their property. The decommissioning process must also be referenced in the lease. The language states that the tenant must restore the surface of the solar panel assembly, as is reasonably practicable, to its original condition at the inception of the lease. Damages resulting from the removal of the tenant's improvements must also be repaired to the extent reasonably practicable. The lease language may also state a time frame (e.g., restoration must occur within a year). The level of restoration may also be dictated by city, county, or state level ordinance.

Solar Production in the United States and Texas

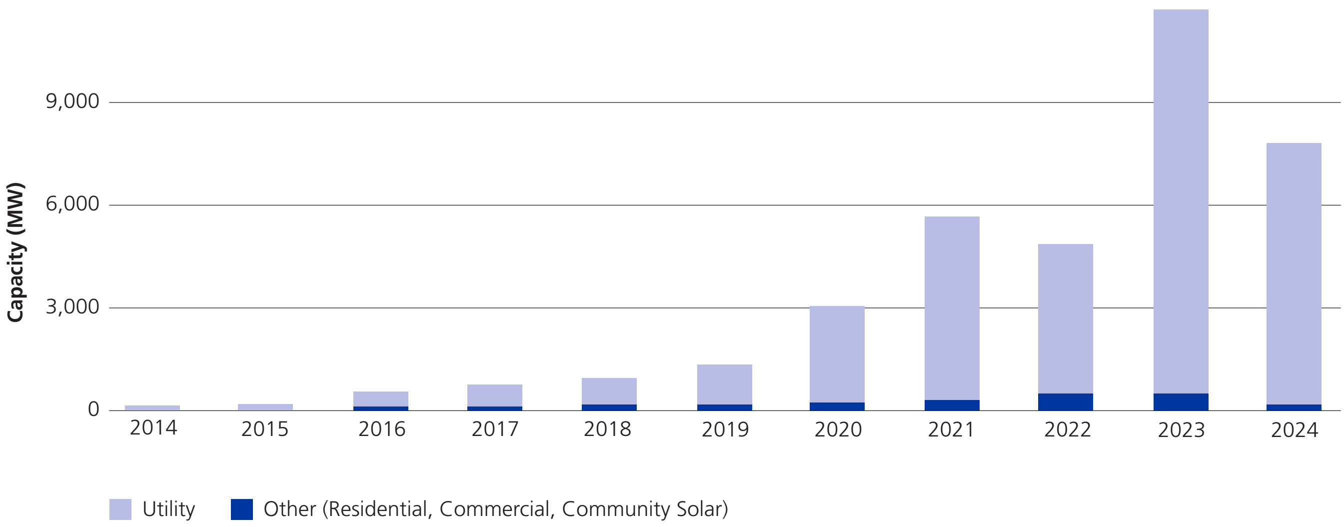
Solar installation and production in the United States and particularly in Texas is growing rapidly. As of the second quarter of 2024, there was approximately 209.8 gigawatts (GW) of solar power capacity installed in the United States, translating to enough electricity generation to power 35.8 million homes. In 2010, solar power accounted for only 0.1% of the United States' electrical generation. In 2024, it accounted for over 64%. Solar power has also outpaced other energy-generating sources in new electric capacity additions. In the second quarter of 2024, solar power accounted for 67% of all new electric capacity added to the grid.[2]

Texas has 34,906.68 MW of installed solar power and ranks second in the United States as of the third quarter of 2024 for installed solar electricity capacity.[3] This translates to enough electricity to power over 4.06 million homes and represents 6.7% of the state's electricity usage.[4] Exhibit 1 shows the capacity of annual solar installations in Texas from 2014 to 2024.

The United States is expected to have nearly 673 GW of total solar capacity installed by 2034.[5] Texas is expected to rank first in installed solar capacity, growing to 50 GW through 2029.[6]

2. Solar Energy Industries Association (SEIA), http://bit.ly/4lRlZGm.
3. SEIA, http://bit.ly/45GGukj.
4. State Solar Spotlight, published for SEIA, September 2024.
5. SEIA, http://bit.ly/47CH5F9.
6. SEIA, http://bit.ly/45GGukj.

Exhibit 1 Annual Solar Installations in Texas



Source: Solar Energy Industries Association (SEIA), http://bit.ly/45GGukj

Perspectives from Published Studies

Research on the impact of utility-scale solar projects on surrounding property values is limited. Relevant published literature revealed that, in general, the public supports the development of large-scale solar projects, yet when specific projects are proposed they are occasionally met with local opposition. Solar panels can affect the visual landscape and reflect sunlight.[7] Survey responses have found that the visibility of a project and its size or installed capacity may affect public perception surrounding a proposed solar project.[8]

To determine if utility-scale solar projects have an impact on the value of surrounding real estate, the academic literature reviewed relies on statistical methods such as regression analysis to study relatively large groups of properties. Regression analysis is a common approach and can be useful in identifying and quantifying average effects across a study area. The average value estimated by a statistical model such as regression analysis does not represent an actual value of diminution for any individual property. Real estate is a highly individualized asset; as a result, effects from something such as a utility-scale solar project could vary across properties and property types and at various distances or viewsheds. Although statistical methods are designed to identify and control for certain differences in property and sale characteristics, they are not capable of accounting for all the influences and nuances present in real estate markets and individual transactions. The larger the geographic area and the wider the variation in property characteristics, the less representative an average effect of each individual home within the study area will be. For example, the average impacts derived from a study of newly constructed single-unit residential properties in a five-mile radius of a solar project will yield more representative output than a study of residential properties located across an entire state. As a result, careful consideration must be given to the application and interpretation of the results from these models.

A search of academic journals revealed three published articles studying the impact of utility-scale solar projects on surrounding property val-

7. M. I. Droes and H. R. A. Koster, "Wind Turbines, Solar Farms, and House Prices," *Energy Policy* (2021): 1–11.
8. P. Roddis et al., "The Role of Community Acceptance in Planning Outcomes for Onshore Wind and Solar Farms: An Energy Justice Analysis," *Applied Energy* (2018): 353–364; and J. E. Carlisle et al., "Utility-Scale Solar and Public Attitudes toward Siting: A Critical Examination of Proximity," *Land Use Policy* (2016): 491–501.

ues. A statistical study of the effect of both wind turbines and solar farms on house prices in the Netherlands was conducted in 2021 using a difference-in-differences approach in which the sale prices of houses near solar farms were compared to the sale prices of houses further away. The study examined 12,650 sales in the Netherlands from 2009 to 2019 surrounding 107 solar farms and concluded that solar farms can result in a decrease in house prices within 1 kilometer by an average of 2.6%.[9]

A recent study conducted by the Lawrence Berkeley National Lab also used a statistical difference-in-differences methodology to analyze 1.8 million residential transactions for properties near more than 1,500 large-scale photovoltaic projects (LSPVPs) in six states. The study concluded that the effects of large-scale solar projects cannot be generalized, as any potential effects depend on many factors particular to individual projects or locations. The study also found that these factors are not uniform across different projects or in different locations, meaning that a result found in one location cannot be applied or used to understand potential effects in another location. Three of the states studied showed no statistically significant impact from LSPVPs, while three states indicated a reduction in sale price for homes only within 0.5 mile of a LSPVP when compared to homes located two to four miles away. Combining data from all six states yielded an average sale price reduction of 1.5% for homes within 0.5 mile of an LSPVP.[10]

A study published in 2023 used hedonic regression analysis to analyze the impact of solar projects on residential property prices in England and Wales and found an average 5.4% reduction in house prices for homes located less than 750 meters, or approximately 0.5 mile, from an operational solar farm.[11]

Market Trends Analysis of Specific Utility-Scale Solar Projects in Texas

Three utility-scale solar projects in two Texas counties were identified for the purpose of analyzing and understanding the potential effects of utility-scale solar projects on single-unit residential property values. The market trend analysis tracks data on single-unit residential real estate transactions involving properties in proximity to solar projects in Tom Green and Bell Counties.[12] With sufficient data, this type of analysis helps us understand overall market patterns and correlates potentially shifting market conditions with specific points in time, such as the date of tax abatement approval for a utility-scale solar project or the date construction begins (an "after" period). Indicators of shifting market conditions include data on historical sale prices, the ratio between sale prices and listing prices, and changes in exposure time (i.e., the amount of time the property is on the market before it sells, or days on market).[13] The analysis performed here considers data on these three factors.

For each solar project area identified, one or more control areas are identified to serve as baseline comparisons to identify any divergences in the two markets. Sales trends in the real estate

9. M. I. Droes and H. R. A. Koster, "Wind Turbines, Solar Farms, and House Prices."

10. For illustrative purposes, a 1.5% reduction of a $350,000 home would be $5,250 or yield a value of $344,750.

11. D. Maddison et al. "The Disamenity Impact of Solar Farms: A Hedonic Analysis," *Land Economics* (2023): 1–16.

12. An analysis of market trends provides an overall picture of market activity. It is not sufficient to identify or quantify potential diminution in value at any one specific property or group of properties. Real estate is a unique asset and subject to individualized influences. Real estate markets, unlike the markets for other goods and services, have never been considered truly efficient because of the unique characteristics of each piece of real estate and the unique perceptions and level of knowledge of each buyer and seller (*The Appraisal of Real Estate*, 15th ed., [Appraisal Institute, 2020], 114). Market trends analyze overall patterns in a market, but these trends do not capture specific differences in property characteristics present at individual homes within each market or unique sale conditions that may have impacted the sale price in certain transactions. While the trend analysis provides us insight on any potential marketwide effect, further analysis is required to identify and quantify diminution in value, if any, at the individual property level. *The Appraisal of Real Estate* discusses the recognized and generally accepted specialized techniques used to identify and quantify diminution in value due to environmental contamination at the individual property level. These methodologies also apply when quantifying any impact to an individual property due to the presence of other types of potentially adverse influences, such as utility-scale solar projects, wind turbines, or high-voltage transmission lines. These recognized techniques include paired sales analysis, case study analysis, multiple regression analysis, and the analysis of income and yield capitalization rates for income-producing properties (*The Appraisal of Real Estate*, 15th ed., 188).

13. *The Appraisal of Real Estate*, 15th ed., 389.

market surrounding the utility-scale solar project, or the "subject area," are compared to sales trends in a "control area" of generally similar properties located near but not proximate to the utility-scale solar project.[14] Ideally, the market data of a subject and control property will historically trend similarly. This allows us to consider the markets in the "after" period and identify if any divergences in the subject market trends exist; this could be in the form of the market demanding lower sale prices for adjacent or proximate properties, longer marketing time or days on market, or larger differences between the original listing price and the ultimate sale price. If a divergence is identified in the subject and control area data that correlates to pertinent dates associated with the utility-scale solar project (e.g., date of tax abatement approval or date construction begins), the divergence serves as an indicator of a potential market reaction to the presence of the utility-scale solar project. The presence of a divergence does not alone prove causation and requires more investigation to determine why it occurred.

Real estate sale prices and other indicators are subject to normal market fluctuations and are influenced by several contributing factors. Although a market trend analysis tracks market metrics and identifies shifting market patterns correlated with the date of a specific activity (e.g., the construction of a proximate utility-scale solar facility), the analysis does not sufficiently identify the causality of any such market shift. The control areas for each analysis were selected to be as similar as possible to the subject area in terms of property and market characteristics, but the market trend analysis does not consider the individual property characteristics of each sale (e.g., age, lot size, condition, number of bedrooms and bathrooms). Therefore, some of the observed differences between the subject and control areas evident in the market metrics studied are due to differences in individual property characteristics and sale terms. These market fluctuations change from year to year and between the subject and control areas studied. The subject is slightly higher than the control area in some years and in some areas, and the reverse is true in other areas and time periods. To quantify diminution in value at a specific property or group of properties, further analysis incorporating and controlling for these individual property variables would be necessary.

While year-to-year fluctuations are typical in real estate data, the presence of a dip or divergence in the subject area relative to the control area that correlates with the date of project announcement or the commencement of construction or operational activities might indicate a negative impact attributable to solar project proximity. The identification of a dip or divergence requires additional research to determine the cause of the market shift. Additional research may include interviews with market participants and paired sales analyses of individual sales.

The study areas considered in this research were selected with key real estate market features in mind. Project location in an area of competing land use was a key criterion. Projects located near and amongst residential properties or where land use is being converted from an alternative use are most likely to see an effect, if one exists. For example, many solar projects have been developed in West Texas that are surrounded by either vacant land or land with similar industrial uses, such as oil and gas production or agricultural use. These projects are also often located miles from residential homes. As the land use of these properties is consistent or not conflicting with the surrounding land use, one can logically presume that proximate land values are likely unaffected. As a result, the analysis here focuses on projects where the surrounding areas have contrasting land use types or where the land use has been converted for the project (i.e., solar acreage previously used as rural residential).[15] Projects of significant size (100 MW or greater) were also selected, as these have the most significant potential viewshed impacts and drastically alter an area's landscape.

Furthermore, rural and suburban residential markets are unique, with different market partici-

14. Identifying control properties near subject properties helps alleviate the potential for locational market differences that could preclude comparability.

15. This is consistent with the body of literature reviewed stating that any potential impact on the value of surrounding real estate would be expected to be highest in areas with residential development.

Exhibit 2 List of Solar Projects Considered by County

Tom Green County	Bell County
Rambler Solar	Five Wells Solar
Concho Valley Solar	

pants and different value considerations.[16] To understand how a utility-scale solar project may affect each market, projects located in both rural and suburban areas as well as in various geographic locations throughout the state of Texas were considered. For example, projects near planned developments (smaller tract properties with homogenous builders and floor plans) are considered as well as projects near more rural residential properties (larger tract properties with unique builders and property features). The varying projects chosen help explain how the unique perceptions of these different market participants may impact the sales of residential properties near utility-scale solar projects.

Solar projects that are either operational or under development or construction are considered in this research. People in markets surrounding projects in these stages are most likely to have full knowledge of the projects. Projects only in the planning phase also have the potential to not come to fruition, and many in the market may be unaware of a project's potential. Therefore, the information about a potential project may not have fully saturated the market. Markets may also react differently during the construction phase and the operational stages; therefore, considering projects at each stage was important.

Utility-scale solar projects that (1) are operational or under development, (2) have a capacity of 100 MW or greater, (3) are surrounded by a sufficient number of residential properties, and (4) are located in either a rural or suburban area were considered for this research. Three utility-scale solar projects in two Texas counties were identified, fulfilling the market and locational characteristic requirements discussed. Market

Exhibit 3 Map of Utility-Scale Solar Projects Considered in the Analysis

trend analysis was performed for these six projects. Exhibit 2 lists the solar projects located in each county, and a map indicating the location of each project is shown in Exhibit 3.

Tom Green County: Rambler Solar Facility and Concho Valley Solar Facility

Two utility-scale solar projects in Tom Green County located on the Edwards Plateau in West Texas were analyzed for the purpose of identifying market impacts to single-unit residential homes located near these projects. The Rambler Solar facility and Concho Valley Solar facility were chosen due to their location near the county seat of San Angelo and proximity to residential developments.

Rambler Solar Facility

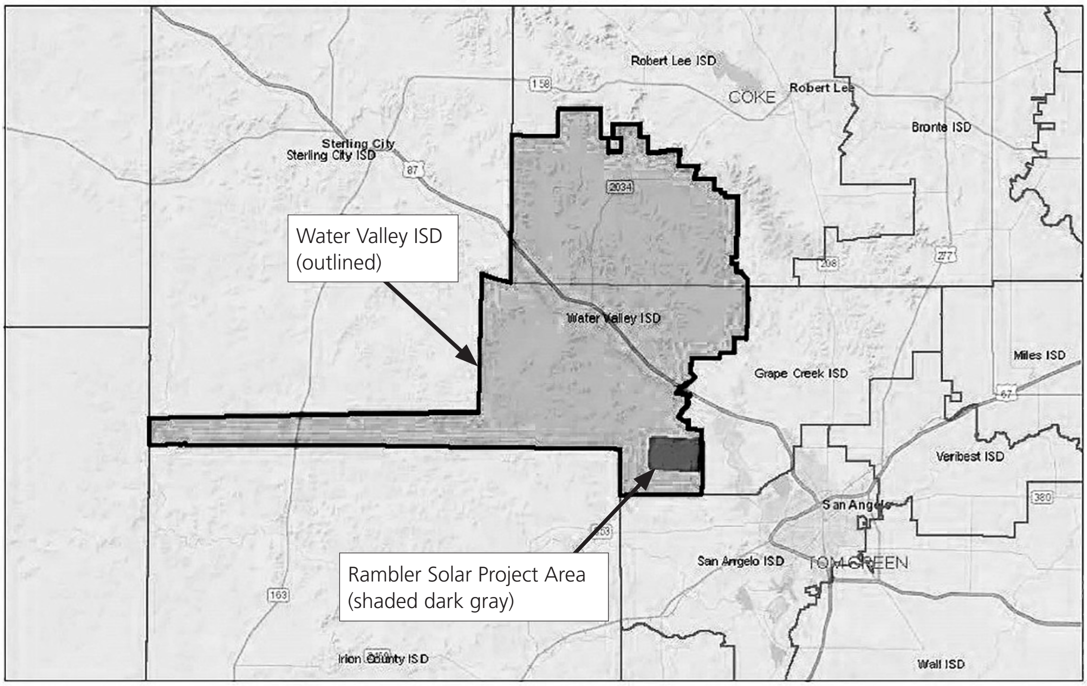
The Rambler Solar project is a 200 MW solar facility located at 8999 Jeremiah Lane, northwest of San Angelo. The facility spans approximately 1,700 acres and contains over 733,000 high-efficiency solar panels (bifacial models). The Rambler Solar facility can power the equivalent of approximately 40,000 homes when operating at full capacity. It was the first solar project in

16. For this reason, it would be inappropriate in a sales comparison analysis to use a property located in an urban center as a comparable sale to a property located in a remote rural location.

Exhibit 4 Aerial Photo of Rambler Solar Facility

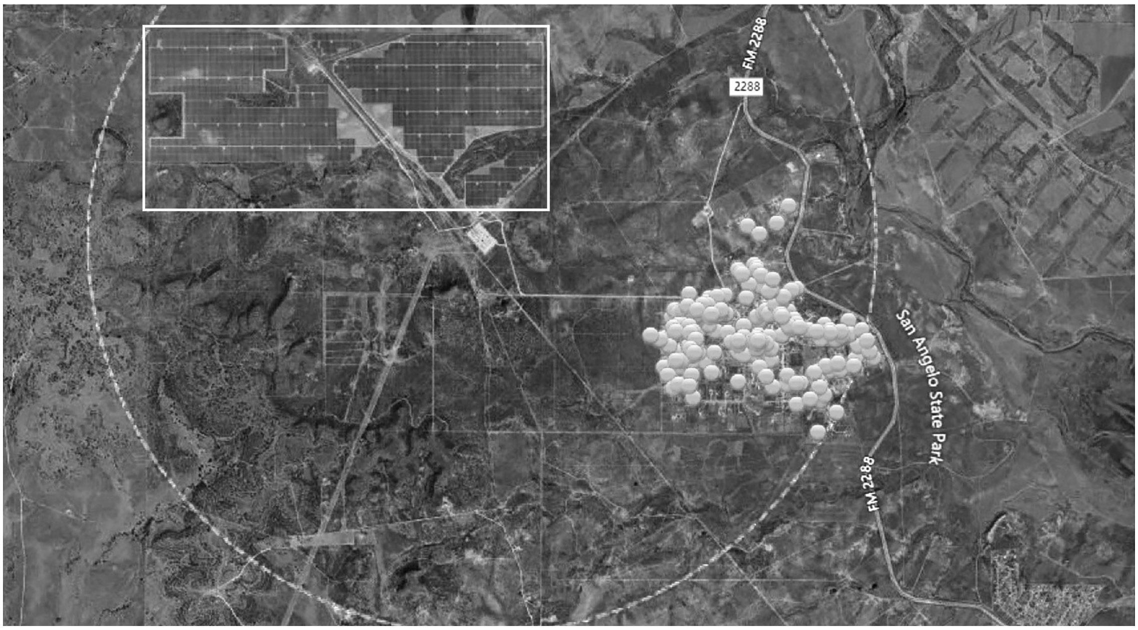
Source: Duke Energy

Exhibit 5 Location of Rambler Solar Facility and Water Valley Independent School District



Source: Application for Appraised Value Limitation to Water Valley Independent School District

Exhibit 6 Sales from July 2020 to March 2023 within a Three-Mile Radius of the Rambler Solar Facility Entrance



Tom Green County and was Duke Energy Renewables' fourth solar generation facility in Texas. A tax abatement application was submitted in January 2019 for the project. Duke Energy acquired the Rambler Solar project from Recurrent Energy in September 2019, and construction began shortly thereafter. Commercial operation began in July 2020. An aerial view of the project is shown in Exhibit 4, and the location of the project in relation to the Water Valley school district is shown in Exhibit 5.

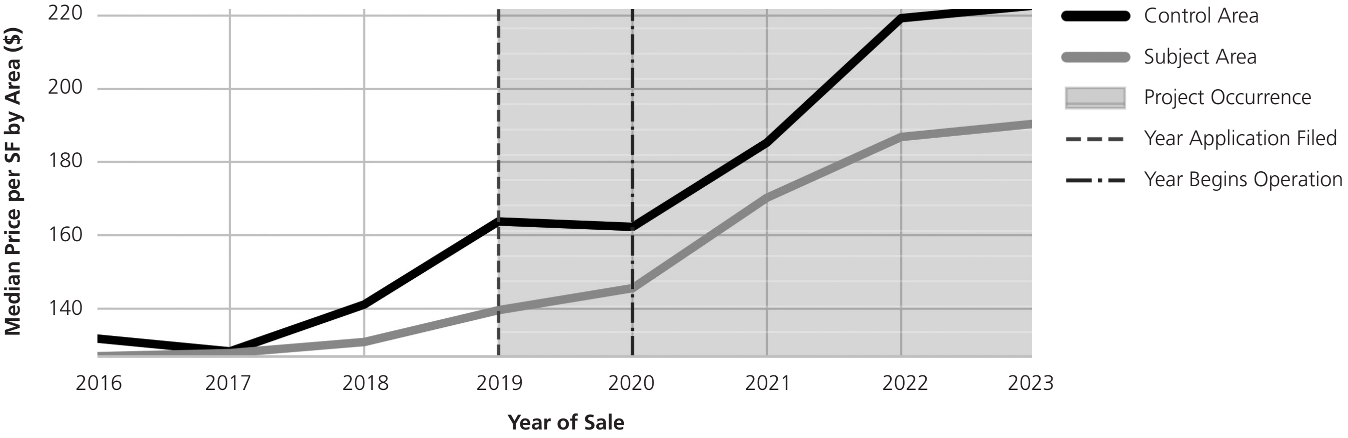
Buffalo Heights, located approximately 1.5 miles southeast of the Rambler Solar facility, is the closest residential development. The planned residential community, first developed in 2008, is located about 10 miles northwest of San Angelo. These homes, built from 2009 to the present, have relatively large lot sizes (on average one acre) and range in size from approximately 1,400 to 3,500 square feet. Data was pulled on sales within a three-mile radius of the entrance to the Rambler Solar facility. As can be seen in the map shown in Exhibit 6, the majority of these sales are located within the Buffalo Heights development.

Several single-unit residential developments similar to Buffalo Heights but not located near a utility-scale solar project were selected for comparison.[17] Control area sales were collected in the area south of San Angelo and north of Christoval (including The Haciendas at Christoval, Oak Mountain Estates, Stonewall Reserve, and Pecan Creek residential developments), as well as the area north of Wall and east of San Angelo (including the Iron Horse and Stonewall Range residential developments). These areas were selected given their similarity to the subject sales in Buffalo Heights in terms of their larger lot sizes, similar approximate distance to San Angelo, and a majority of homes with relatively newer construction (post-2000). Data on all sales transacting through the Navica MLS from January 2016 through March 2023 was collected for the purposes of this analysis.[18]

17. Residential developments with similar property characteristics were selected for use as control areas. Homes with different characteristics (e.g., homes on smaller lots within the city of San Angelo or older homes) may be impacted differently by changes in economic conditions. Therefore, the selection of control areas with similar characteristics is imperative for truly identifying a benchmark rather than considering citywide or countywide averages.

18. Because we are using the MLS, not all sales occurring in the areas are necessarily being captured, and this is therefore a representative sample.

Exhibit 7 Median Price per Interior Square Foot for the Subject and Control Areas for the Rambler Solar Facility



Data on the median price per interior square foot of living space, sale price–to–list price ratio, and days on market was obtained for subject and control area sales. If the announcement or construction of the Rambler Solar project had a negative impact on sale prices in the surrounding market area, the sales data would dip or diverge in the subject area as compared to the control areas and correlate with relevant project dates (i.e., the date the project was announced or the date of construction). If a dip or divergence is evident at a different point in time (not correlated with the project under study), it is unlikely to be associated with the solar project. Similarly, an impact for the other metrics would be in the form of a lower sale price–to–list price ratio (i.e., the sale price of the property is lower compared to the list price) or the average days on market increases following the key dates.

Exhibit 7 depicts the median price per interior square foot in both the subject area and the identified control areas. The price per interior square foot of living space rose in a general trend over time for both the subject and control area properties. Median price per interior square foot in the identified control areas is higher than the price per interior square foot in the subject area, both before and after the construction of the Rambler Solar facility. This is likely due to the newer construction in the control areas that has become available in recent years. The control area median price per interior square foot began to rise relative to subject area prices in 2017. The positive divergence in the control areas continued until 2019. Key dates to consider are Rambler Solar facility's tax abatement application in January 2019 and the publicity surrounding the project's purchase by Duke Energy in September 2019. During this 2019 time frame, median prices leveled out in the control areas while prices in the subject area near the Rambler Solar facility continued to rise, narrowing the price gap between the two areas. The prices in both areas generally trended together throughout 2020, the year Rambler Solar began operations (in July). In 2022, control area prices grew at a faster rate, which is consistent with the number of new construction homes becoming available in the control areas. New construction often brings a higher price per interior square foot than the price per interior square foot of relatively older homes. (Year values on the x-axis represent the beginning of each year.)

Exhibit 8 graphs days on market, showing similar trends for both proximate and distant homes and indicating no market resistance. Exhibit 9 graphs the sale price–to–list price ratios. Sales proximate to the Rambler Solar facility tend to sell consistently at full asking price, particularly in more recent years. This contrasts with homes further away, which often sell at a discount relative to their original listing price.

These market trends do not show any evidence of negative impact correlated with the announcement or construction of the Rambler Solar facility. To the contrary, median price per interior square foot improved in the 2019–2020 time frame rela-

Exhibit 8 Days on Market for the Subject and Control Areas for the Rambler Solar Facility

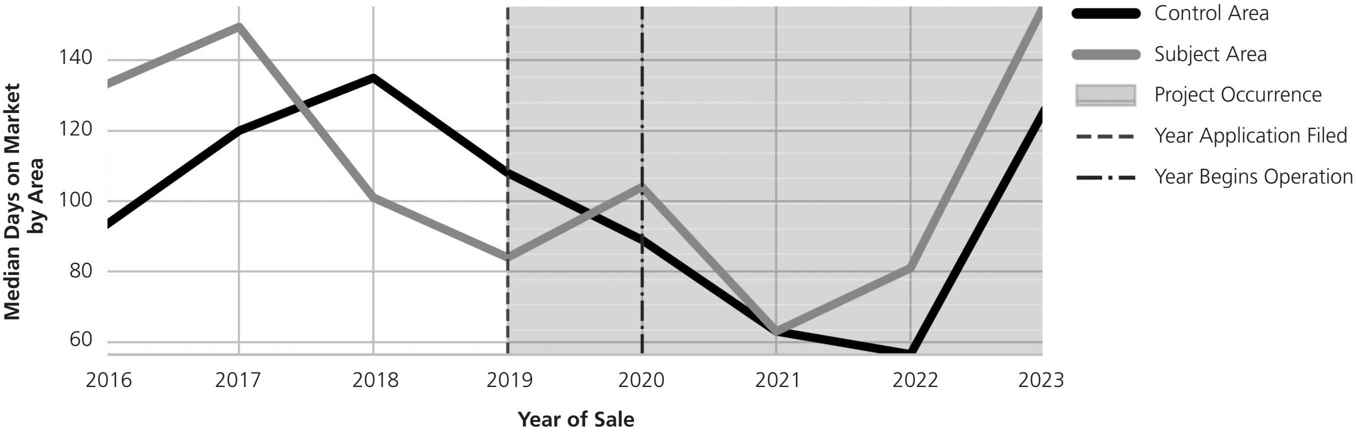
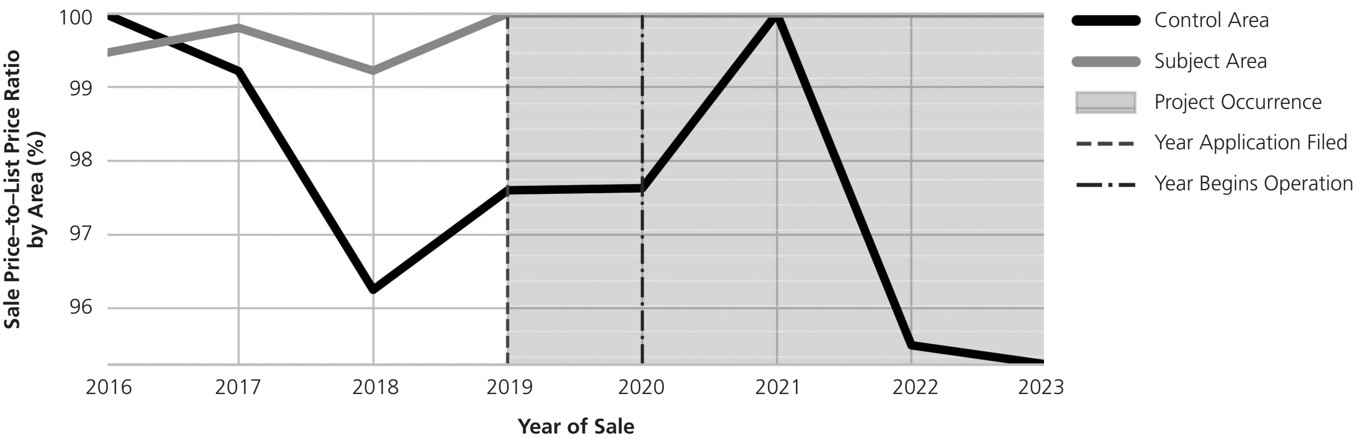


Exhibit 9 Sale Price–to–List Price Ratios for the Subject and Control Areas for the Rambler Solar Facility



tive to control area prices as the Rambler Solar project was announced and constructed. Subject area sales near the Rambler Solar project sell at a higher sale price–to–list price ratio on average, and the days on market has fluctuated over time but is generally consistent with the marketing time for homes in the control area. It should be noted that the subject area homes in Buffalo Heights do not have a view of the Rambler Solar project. These results are consistent with the literature, which concludes that property value impacts are most likely to occur for residential properties with a view of a utility-scale solar project versus residential properties in proximity to a solar project but without a direct view.

Concho Valley Solar Facility

The Concho Valley Solar project is located approximately 1.5 miles to the southeast of a residential development in San Angelo. Some rural homes are located in closer proximity to the Concho Valley Solar project. The 159.8 MW project, with an address of 467 Ratliff Drive, consists of approximately 700 acres of land. It is the second completed solar project in the county. An application for tax abatement was received in November 2019, construction began in November 2021, and the project became operational in December 2022.

Data was collected on subject area residential sales from January 2016 to the present. Compara-

Exhibit 10 Sales from January 2016 to March 2023 within a Three-Mile Radius of the Concho Valley Solar Facility

ble properties were located within three miles of the Concho Valley Solar facility, south of the Concho River and Highway 87 N, which serve as physical barriers separating properties north of the solar project.[19] These sales are primarily located in two neighborhoods in San Angelo: the Country Club neighborhood and the Nasworthy neighborhood. Exhibit 10 maps sales within a three-mile radius of the facility between January 2016 and March 2023.

For the purpose of this analysis, sales located in these same neighborhoods but north of the Concho River and Highway 87 and sales located west of Lake Nasworthy were selected as control areas. These sales are in the same general neighborhood as the subject sales but are physically separated from the Concho Valley Solar facility by water or a major highway.

Exhibit 11 graphs the median price per interior square foot for the subject and control areas. It shows that the prices of properties close to the Concho Valley Solar project converged with, and occasionally outpaced, properties further away. This trend was present in more recent years during the construction and completion of the project.

Exhibit 12 graphs the days on market for the subject and control areas, and Exhibit 13 graphs the sale price–to–list price ratios for the subject and control areas. The number of days on market were generally similar or slightly lower (i.e., selling quicker) than they were for homes further away. This was a difference that both predated and continued after the announcement and construction of the Concho Valley Solar project. Sale price–to–list price ratios also trended closely with homes further away both during and after the announcement and construction phases of the project, with no discernible divergence occurring in the data.

These trends show no evidence of market impact to homes within three miles of the Concho Valley Solar facility and south of the Concho River and Highway 87 N. To the contrary, subject area sale prices have improved relative to the control area sales since 2020, the years following the announcement and construction of the Concho Valley Solar facility. Both sale price–to–list price ratios and days on market have generally trended with that of control area properties throughout the time period studied, both before

19. A physical barrier acts as a feature that physically separates areas and as a result creates differing experiences for property owners across such divides.

Exhibit 11 Median Price per Interior Square Foot for the Subject and Control Areas for the Concho Valley Solar Facility

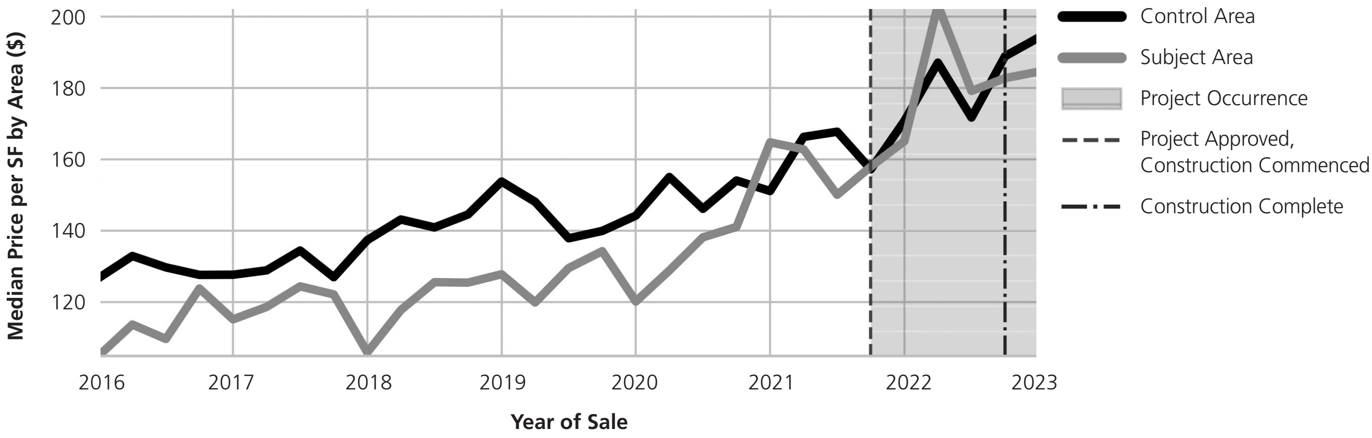


Exhibit 12 Days on Market for the Subject and Control Areas for the Concho Valley Solar Facility

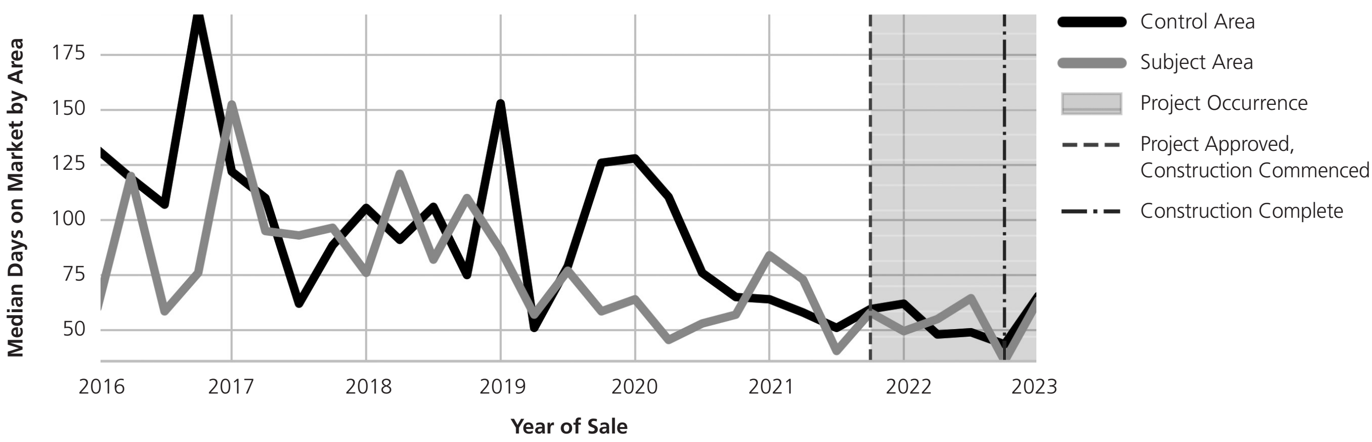


Exhibit 13 Sale Price–to–List Price Ratios for the Subject and Control Areas for the Concho Valley Solar Facility

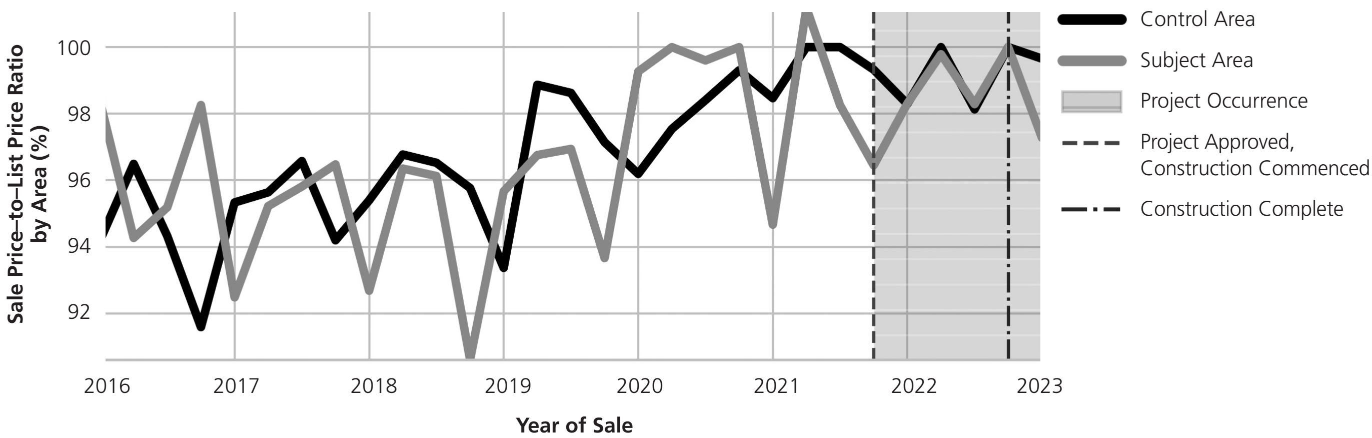


Exhibit 14 Map of Individual Sales Near the Concho Valley Solar Facility

Note: This aerial was as of March 2021, prior to construction of the Concho Valley Solar project. The approximate boundary of the solar project is outlined in white.

and after the announcement and construction of the Concho Valley Solar facility.

Similar to the residential sales surrounding the Rambler Solar project, the majority of subject area sales do not have a direct view of the Concho Valley Solar facility. However, three rural residential sales have occurred since the announcement of the project that were either adjacent to the facility or have a direct view of the facility. These sales were considered in more detail due to their proximity to or view of the Concho Valley Solar project. A single-family residential home on Ratliff Road, adjacent to the project, sold on March 8, 2021, for $709,000. The sale occurred after the Concho Valley Solar project announcement and tax abatement approval but before construction of the project began. The seller was the listing agent. While confirming the marketing period of the transaction, the seller indicated that the project had no effect on the sale.[20] In 2022, two homes sold on Countryside Road in close proximity to the Concho Valley Solar facility during the construction period. A single-family home on Countryside Road sold on July 1, 2022, for $900,000. A high-voltage transmission line is also visible from this property. The listing agent stated that the 71 days on market was faster than the typical marketing time for homes selling in the $900,000 range.[21] The agent stated that the property sold closer to the date it was listed. The longer closing period was due to the buyer having a contingency to sell their other property. When asked about the Concho Valley Solar projects, the agent stated that the project had not affected the sales they have been a party to, nor have buyers shown concern.[22] The other property on Countryside Road sold on September 14, 2022, for its full listing price of $565,000. The sale was confirmed with the agent, who said that while some buyers had questions about the Concho Valley Solar project, it ultimately did not impact the sale price.[23] The map in Exhibit 14 shows the location of these individual sales relative to the Concho Valley Solar project, outlined in white.

Bell County: Five Wells Solar Facility

Several utility-scale solar projects are being approved and constructed in Bell County, located in Central Texas along Interstate 35 between Austin and Waco. The first of these projects, the Five Wells Solar project, is located east of Temple along Highway 190 near the town of Rogers. The application for tax abatement for the Five Wells Solar project was submitted in July 2021 and was approved in May 2022. Construction of the project began in late 2022 and was still underway as of 2023. The Five Wells Solar project comprises approximately 8,000 acres and will have a solar production capacity of 350 MW.

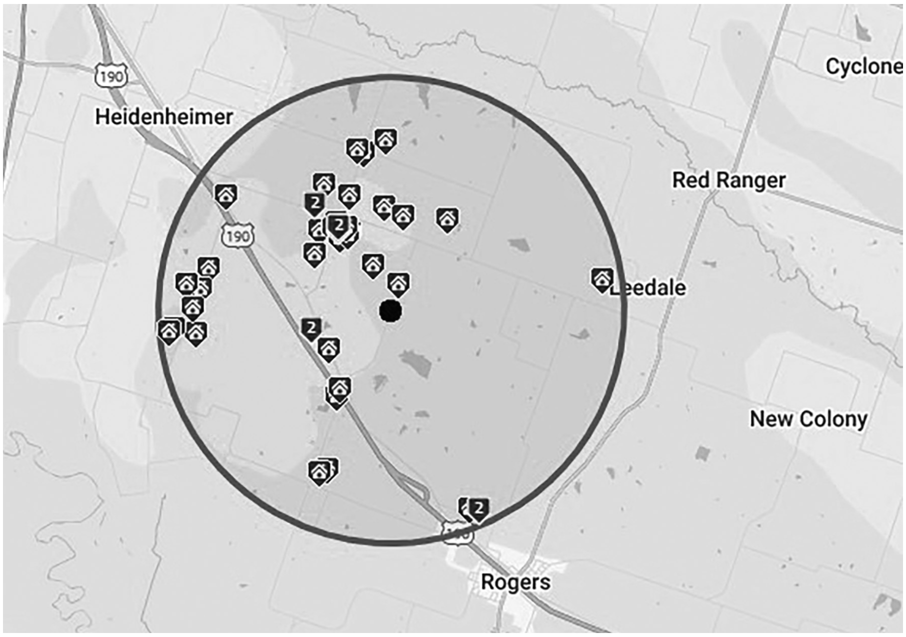
20. Conversation with agent involved with the sale on May 30, 2023.

21. Agent indicated that the typical days on market was closer to 150 days.

22. Conversation with agent involved with the sale on May 30, 2023.

23. Conversation with agent involved with the sale on March 5, 2023.

Exhibit 15 Sales from January 2018 to March 2023 within a Three-Mile Radius of the Five Wells Solar Facility



The residential development in this area is more rural in nature as compared to the residential planned developments analyzed in Tom Green County. These tracts primarily consist of rural residential homes on small acreage lots. The large size of the solar project combined with the sloping topography in the area result in a greater number of proximate homes that have a view of the Five Wells Solar facility. For the purposes of this analysis, residential sales within a three-mile radius of the address point of the Five Wells Solar facility at 9161 Five Wells Road, Rogers, and occurring between January 2018 and March 2023 (as shown in the map in Exhibit 15) were analyzed as subject sales. All Bell County residential sales outside of the three-mile radius but east of Highway 95 and Interstate 35 were designated as control area sales. Both the subject and control area sales are primarily rural residential properties located in eastern Bell County with similar locational influences and market appeal.

Exhibit 16 graphs the median price per interior square foot for the subject and control areas. After the approval of the tax abatement and during construction of the Five Wells Solar project, the median price per interior square foot for homes near the Five Wells Solar facility has increased significantly compared to homes farther away. Before the project was announced or construction started, prices in the area were generally lower relative to home prices further away. This reversed within a year of the project's announcement. In terms of median price per interior square foot, homes proximate to the Five Wells Solar project tend to sell for higher sale price–to–list price ratios (meaning few to no discounts or selling above the asking price).

As shown in Exhibit 17 which graphs days on market for the subject and control areas, proximate properties appeared to take longer to sell—although this was consistent for years prior to the pandemic. To better understand the cause of these longer marketing periods, realtors involved in several subject area transactions were interviewed. Exhibit 18 graphs the sale price–to–list price ratios for the subject and control areas.

The trends graphed in Exhibits 16–18 show no evidence of market impact to homes within three miles of the Five Wells Solar facility. To the contrary, subject area sale prices have been strong and improving relative to the control area sales since 2021 and in the years since the Five Wells Solar facility announcement and construction. Sale price–to–list price ratios are strong, showing an average ratio over 100% for subject area sales

Exhibit 16 Median Price per Interior Square Foot for the Subject and Control Areas for the Five Wells Solar Facility

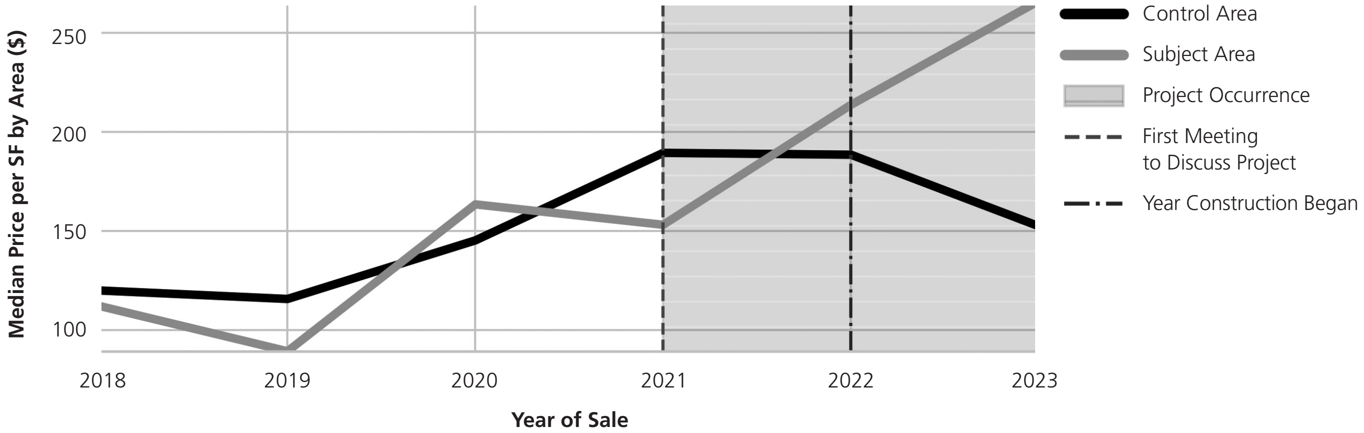


Exhibit 17 Days on Market for the Subject and Control Areas for the Five Wells Solar Facility

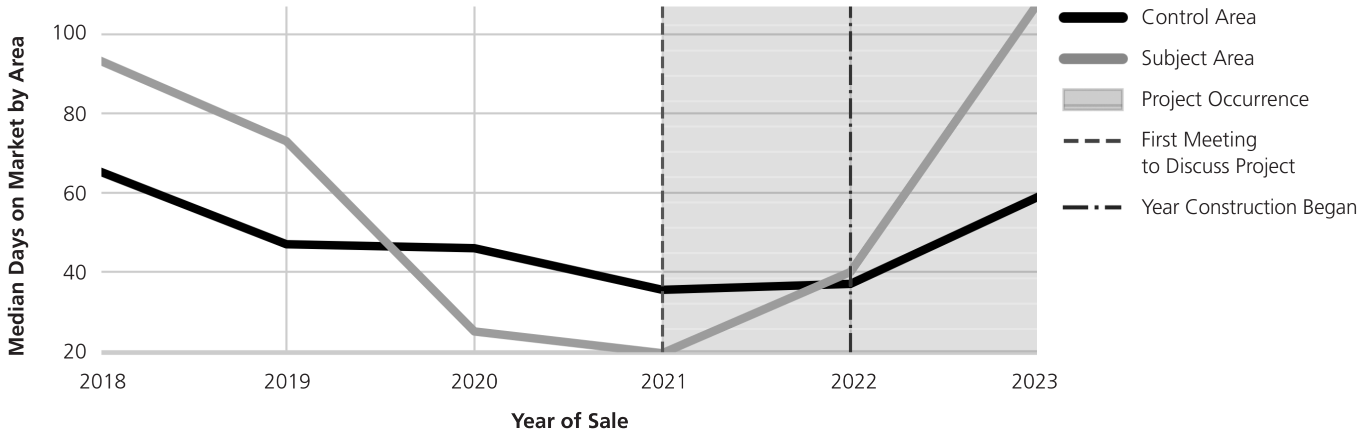
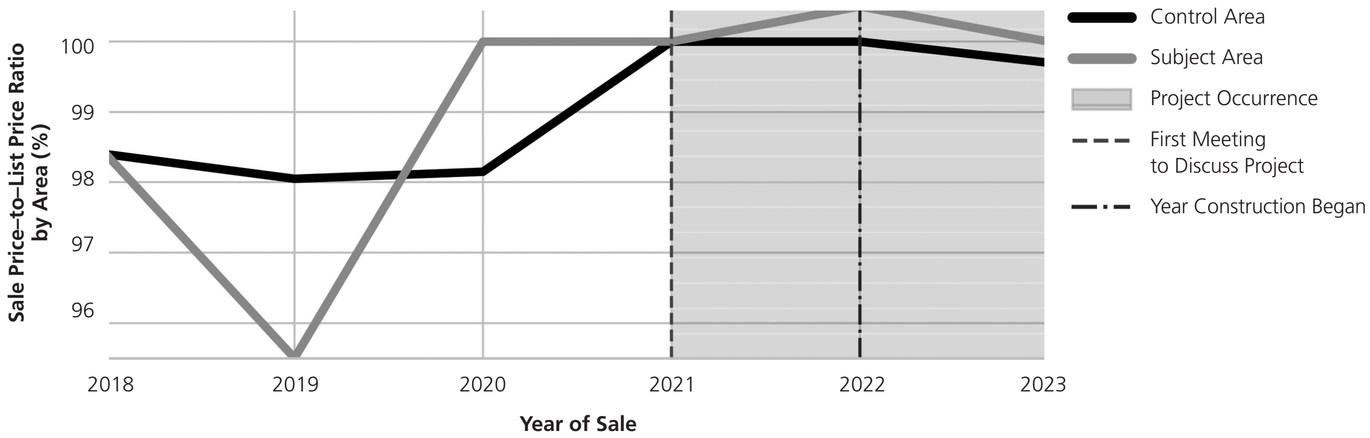


Exhibit 18 Sale Price–to–List Price Ratio for the Subject and Control Areas for the Five Wells Solar Facility



in 2022. Days on market has increased over time and relative to the control area, but conversations with realtors involved in several transactions revealed that the longer marketing period was not associated with the Five Wells Solar facility (instead attributable to factors such as a need for extensive repairs, a buyer unable to obtain financing, or the property still being under construction). During these conversations, agents stated that the project did not come up in their discussions. They have found that the market, in general, is aware of the Five Wells Solar project, and it has not affected sales.[24] One agent stated that they were aware of individual cases in which the solar project was a consideration for the potential buyers and that the project, as well as current market conditions, contributed to longer marketing periods for a property. This suggests that although widespread market impacts are not evident, individual properties in very close proximity or with a direct view of a solar project may potentially experience impacts in some areas. This reinforces the need for property-specific analysis when estimating diminution in value at an individual property.[25]

Summary of Research and Findings

The market trend analysis of single-unit residential properties near three utility-scale solar projects in two Texas counties—in varying residential markets and at different stages of project development—showed no evidence of negative market-wide impact. The sale metrics of price per interior square foot, sale price–to–list price ratios, and days on market in subject areas follow generally similar trends when compared with control area sales located further from solar projects. These findings were consistent across the areas studied.

Similarly, published literature studying market-wide impacts in the Netherlands, England, Wales, and six states in the United States found little to no impact on residential homes proximate to utility-scale solar projects (with average impacts ranging from 0% to −5.4%). When impacts were found, the reduction in price was noted for homes located approximately 0.5 mile or less from the solar project. One study noted that the effects of large-scale solar projects cannot be generalized, as any potential effects depend on many factors particular to individual projects or locations. Survey responses found that the visibility of a project and its size or installed capacity may affect public perception surrounding a proposed solar project.

Conclusion

Although support exists for the development of green energy in the form of large-scale solar projects, specific proposed projects are occasionally met with local opposition. Homeowners in surrounding areas may express concern regarding negative impacts to their properties due to the construction and operation of a large-scale solar project. This research was intended to address the question of whether, in general, homeowners proximate to a large-scale solar project should expect to see a drop or decline in property value.

The market trend analyses of residential homes in markets proximate to three large-scale solar projects did not provide any evidence of a negative impact on sale prices, days on market, or sale price–to–list price ratio. As noted, these findings cannot be generalized or assumed to apply to every market or solar project, as any potential impacts depend on many factors particular to individual projects and locations. For example, a home directly adjacent to a large-scale solar project and with a direct view of the solar panels may experience a unique impact compared to the overall market. However, these findings indicate that a negative impact from proximity to a large-scale solar project cannot be assumed and individual, market-specific analysis must be conducted to support any estimate of diminution in value. The market trends analyses presented here, in combination with the findings from published literature, provide evidence that market demand exists at competitive prices for residential properties proximate to a large-scale solar facility.

24. Conversation with brokers and agents involved with sales on Wedel Cemetery Road and Shaw Road.

25. Conversation with agent involved with sales on FM 2184 and Sun Circle.

The body of literature addressing the impacts of large-scale solar projects on property value is limited, and there is opportunity for future studies on this topic to refine and supplement these general findings. Additional research utilizing paired sales analyses to study specific residential properties at different proximities to the solar projects and with differing views would add additional insight to the factors that contribute to individual impacts at specific properties. Statistical regression analysis could also be used to account for varying property characteristics such as size and age and to test for varying impacts at different proximities and for properties with differing views.

About the Authors

Erin Kiella, PhD, is executive vice president and consultant at Real Property Analytics Inc. Kiella has been with Real Property Analytics since 2015. Her expertise is in complex real estate valuation techniques used to quantify potential property value diminution from detrimental conditions, including environmental contamination or alleged contamination from on-site and off-site sources. She has expertise in statistical modeling and econometrics. Kiella has provided litigation support involving the development of damage and rebuttal opinions in class action and mass tort litigation cases throughout the United States, both at the certification and merits stages. Kiella was formerly an assistant research economist with the Real Estate Center at Texas A&M University, where her research focused on rural land market trends, agricultural lending, and estimating econometric models forecasting rural land prices in Texas, Alabama, Mississippi, and Louisiana. Before joining the Real Estate Center in January 2018, Kiella was a strategy consultant with California-based The Wonderful Company, research assistant with the Agricultural and Food Policy Center at Texas A&M University, and consultant with the Federal Reserve Bank of Chicago. She has lectured several courses at Texas A&M University. Kiella has a PhD in agricultural economics from Texas A&M University and a BBA in finance and economics from Loyola University in Chicago, with honors. She is also a member of the American Society of Farm Managers and Rural Appraisers. **Contact: erin@rpa-inc.com**

Jennifer Pitts, MAI, CRE, is the president of Real Property Analytics Inc. and has over fifteen years of experience in real estate consulting and appraisal throughout the United States and Canada. She specializes in analyzing complex valuation issues, including the valuation of properties impacted by environmental contamination or other disamenities, and has provided expert testimony on litigation matters before federal and state courts. These matters involved the impacts of soil, groundwater, airborne and surface water contamination, and alleged contamination on property values; real estate issues related to proposed environmental class actions; the impacts of high-voltage electric transmission lines on property values; the valuation and highest and best use of properties subject to eminent domain; and real estate development feasibility. She has familiarity and experience with specialized valuation methods used in these types of assignments, including econometric and statistical modeling, paired sales analysis, and case study research. Pitts is a graduate of Texas A&M University with a master's degree in land economics and real estate and a bachelor's degree (summa cum laude) in finance. She is a designated member of the Appraisal Institute (MAI) and a Counselor of Real Estate (CRE)—a professional designation that is awarded by invitation only to a select number of professionals recognized for their expertise, experience, and ethics in providing real estate counseling and advisory services. She is a state-certified general real estate appraiser in Texas and other states. She has coauthored several articles for *The Appraisal Journal* and *The Journal of Real Estate Literature*. **Contact: jennifer@rpa-inc.com**

Christopher Yost-Bremm, PhD, is an assistant professor of finance at San Francisco State University. Yost-Bremm has been with Real Property Analytics Inc. since 2014, developing and critiquing statistical methodologies involving real property on behalf of numerous firms and individuals. He has significant experience in analyzing the impacts of environmental contamination, particularly under class action or mass tort claims (at both the certification and merit stages). In addition, Yost-Bremm has provided analytic valuation services for mining and other industrial properties and has analyzed numerous other commercial and residential property types under complex economic situations, such as low-income housing tax credits, property diminution in insurance claims, transferable development rights, and partial takings in eminent domain, among other matters. In addition, through the use of complex econometric models, he has studied the impacts of environmental contamination on income capitalization rate risk premiums and sale prices for commercial properties in Southern California and coauthored an article on this topic. He has published real estate and financial valuation work in numerous academic journals, including *The Journal of Behavioral Finance*, *Cities*, *The North American Journal of Economics and Finance*, *The Review of Behavioral Finance*, and *The Journal of Computer Information Systems*. He received the Richard U. Ratcliff Award from the Appraisal Institute, presented annually for the most outstanding original article by an academic author published in *The Appraisal Journal*, for his regression study on commercial property values amid environmental contamination. Yost-Bremm holds a PhD in finance from Texas A&M University, an MBA from California State University (with distinction), and undergraduate degrees in management and international economics (with honors). He is a state-certified general real estate appraiser in California. **Contact: chris@rpa-inc.com**

Additional Resources

Suggested by the Y. T. and Louise Lee Lum Library

Appraisal Institute

- **Lum Library Online Catalog [Login required]**
  Subject headings: "Energy efficiency" OR "Solar energy" AND keyword: "farm"
- **Lum Library Knowledge Base Bibliographies [Login required]**
  Solar farms

PNAS RESEARCH ARTICLE | ECONOMIC SCIENCES

Impact of large-scale solar on property values in the United States: Diverse effects and causal mechanisms

Chenyang Hu[a], Zhenshan Chen[a,1], Pengfei Liu[b], Wei Zhang[a], Xi He[a], and Darrell Bosch[a]

Affiliations are included on p. 9.

Edited by Catherine Kling, Cornell University, Ithaca, NY; received September 10, 2024; accepted April 24, 2025

As the renewable energy transition continues into less receptive communities, local opposition is expected to intensify, potentially slowing the process. Since the local impacts are neither well quantified nor widely recognized, we lack policies and common practices to mitigate the potential associated welfare loss in affected communities. Based on a nationwide dataset combining property transactions and large-scale solar photovoltaic (LSSPV) sites, we analyze the heterogeneous effects of LSSPV on property prices and the associated causal pathways. Difference-in-differences estimates show that LSSPV significantly increases agricultural or vacant land value by about 19.4% within a 2-mile radius, while simultaneously reducing residential property values within 3 miles by about 4.8%. The estimated average negative impact on home values is primarily driven by site proximity and diminishes with both distance and time. Effect estimates are more robust to alternative specifications when proximity pairs with visibility rather than invisibility, but no evidence suggests visibility significantly amplifies the proximity effect. Heterogeneous effect estimates indicate that high solar lease potential, being in heavily Democratic-leaning counties, and brownfield redevelopment largely mitigate the negative residential value impact. The analysis reveals no significant heterogeneity across a few factors, including varying site visibility, directional orientation of properties relative to the LSSPV site, and different tracking systems. Evidence indicates that the negative impact on residential values might mainly stem from negative perceptions, but channels through physical conditions cannot be entirely dismissed. Our assessment provides benchmark information for local externality mitigation plans, potentially reducing community opposition and expediting the renewable energy transition.

solar energy | economic valuation | econometric analysis | renewable energy transition

Significance

Large-scale solar projects are crucial for decarbonizing the US economy, but growing local resistance may impede the renewable energy transition. We estimate the impact of large-scale solar on property prices and the underlying pathways using 8.8 million sales and 3,699 solar sites in the United States. Exposure to solar sites decreases nearby residential home values but increases land values. For large-lot homes, the increase in land value largely mitigates the negative residential impact. Varying county political leaning and land use histories result in significantly different residential value impacts. Empirical evidence indicates that the current negative residential impact might represent a stigma effect attached to solar sites. Our findings provide important insights for addressing local resistance against large-scale solar projects.

As the cost of solar energy continues to decline (1), solar is likely to remain the leading source of renewable energy in the United States (2). Although the climate benefits of large-scale solar photovoltaic (LSSPV) are widely recognized, the siting of LSSPV projects has encountered increasing local resistance (3–5). As the renewable energy transition deepens into less receptive communities, local opposition is expected to intensify and slow down the transition process. Anecdotal and qualitative evidence suggests that the local concerns are primarily driven by negative aesthetic impacts, decreased property values, environmental injustice, and adverse impacts on local agriculture (3, 6, 7). However, these negative impacts are not well quantified, and we lack policies or common practices to mitigate the potential welfare loss in affected communities.

LSSPV facilities can significantly alter local amenities in residential areas. Recent studies suggest that proximity to a solar site may reduce home values (8, 9) due to diminished amenities such as adverse visual impact (10). The geometric and highly reflective surfaces of LSSPV facilities can be seen as unattractive and disruptive, particularly in natural or agrarian settings (11). There are other potential disamenities associated with LSSPV that may not be revealed immediately after site installation, including disrupted ecosystems and wildlife habitats (12, 13), increased soil erosion and water runoff, and degraded air quality (14). Moreover, negative perceptions of disamenities could lead to property value losses that are unrelated to actual levels of physical disamenities, a phenomenon known as the stigma effect in the housing market (15, 16).

Solar development can affect land prices considerably. An LSSPV facility typically requires between 5 and 10 acres per MWac of generating capacity. Agricultural land has been the most common land type for LSSPV development, due to its suitability, such as being flat, dry, cleared of natural vegetation, and close to electric infrastructure (17, 18). A recent projection from the American Farmland Trust shows that solar projects could occupy over 7 million acres by 2040, with 83% of new installations on farmlands and ranchlands, half of which are on highly productive land (19). If we consider the potential future surge in

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The authors declare no competing interest.

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[1]To whom correspondence may be addressed. Email: zhenshanchen@vt.edu.

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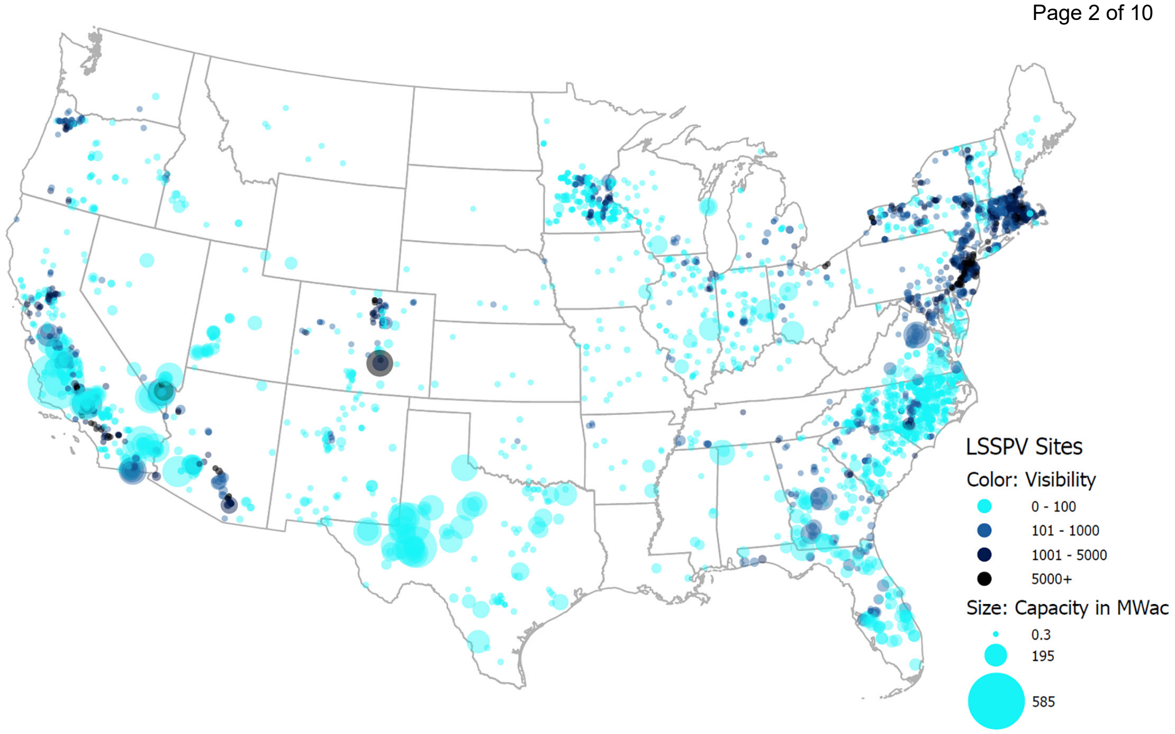

Fig. 1. Map of LSSPV locations, capacity, and visibility. The size of circles indicates the capacity of each LSSPV site. The colors represent the visibility of each site. Visibility is measured in the number of local (<6 miles) residential homes with a view of that LSSPV site.

energy demand, e.g., electrifying the transportation sector and establishing AI data centers, the required farmland for solar energy production could be much higher than the projected 5.8 million acres. In the long run, the land use competition between solar development and agricultural production is likely to increase the scarcity of farmlands, especially at the urban fringe. In the short run, leasing the land for solar energy production provides higher financial returns than traditional agricultural operations, which may drive up farmland prices and elevate farming costs.

Existing studies provide suggestive evidence that visual impacts and loss of property values are the two leading concerns for local oppositions (3, 10).[*] These local impacts of LSSPV represent classically defined externalities, as no widely established mechanism exists for solar site owners to compensate neighboring communities for potential negative effects. Quantifying these externalities is important to establishing solar siting procedures that adequately compensate the community and allow socially optimal allocations of resources. More importantly, as solar sites are initially developed in receptive communities, siting efforts are expected to become more challenging when the renewable energy transition continues. Studies have suggested that a major proportion of proposed LSSPV projects were denied or withdrawn due to local resistance (5, 10).[†] Clarifying and addressing the externalities of LSSPV development will help alleviate local opposition to solar development and accelerate the energy transition.

Utilizing property-level transaction data and detailed LSSPV site information, we present a comprehensive nationwide analysis to estimate and quantify the externalities of LSSPV facilities facing nonresidential and residential properties. We employ a Difference-in-Differences (DID) identification framework to investigate the effects of solar projects on nearby property values. Previous studies have employed similar methods to investigate the property value effects of solar site exposure in a few selected states (8, 9, 20). While viewshed analyses and visual impact investigations are prevalent for wind site studies (e.g., refs. 21–25), previous solar studies have not measured site visibility or quantified the associated visual impact, despite some indicating its relevance (e.g., ref. 26). In contrast to previous solar studies focusing on site proximity, we additionally assess the impact of site visibility and its interaction with proximity. Specifically, we create a geospatial database showing the visibility from every residential home to nearby LSSPV facility in the contiguous United States (Fig. 1, see *Data and Methods* for details). With the average effects showing the general size of welfare changes in the neighborhood, we further differentiate the impact mechanisms and provide information for a compensation plan for the local externalities generated by LSSPV sites.

Our analysis demonstrates that LSSPV sites affect local residential property values and land values differently. We separately analyze transactions on three types of properties. The first type is residential properties (hereafter "residential homes" or "residential") with a lot size under five acres (i.e., the typical minimum acreage requirement for a solar lease), where LSSPV effects primarily stem from impacts related to residential amenities. The second type involves agricultural or vacant land above five acres (hereafter "agricultural land" or "ag-land"), where LSSPV effects mainly result from potential solar lease-induced land use value changes. The third

[*]Crawford et al. (3), based on 33 interviews with residents, found that the top three of residents' most common concerns of large-scale solar are "negative aesthetic impact", "decreased property values", and "misuse of agricultural land". Moreover, a survey conducted in 2023 by Nilson et al. (10) shows that 123 developers report visual concerns to be the most common concern for utility-scale solar, followed by property value loss and agricultural land loss.

[†]An earlier study from Mulvaney (5) showed that nearly half of the LSSPV projects proposed from 2005 to 2016 in the Southwest US were denied or withdrawn, largely due to local resistance. A survey conducted in 2023 by Nilson et al. (10) suggests that among solar industry respondents across the US, 95% agree that community opposition will get in the way of decarbonization goals. The same survey shows that about 40% of planned solar projects were canceled while the remaining 60% were delayed by at least 6 months in the last 5 y, and local ordinances and community opposition are among the leading causes of cancellation.

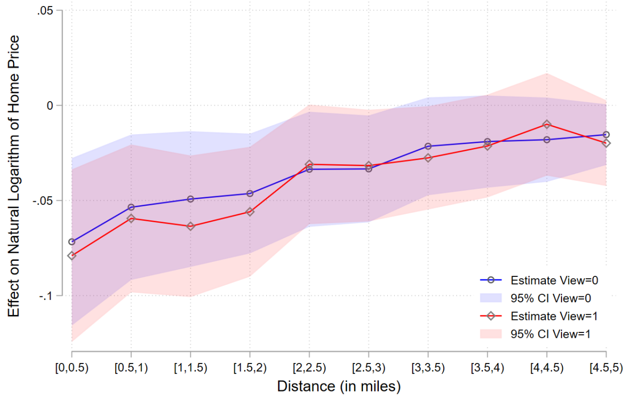

Fig. 2. Effects of proximity and view on residential home value. The blue line connects the coefficient estimates of proximity bins without view, obtained by interacting the proximity bins, the binary posttreatment indicator, and the no-visibility indicator (i.e., equals 1 if no site view). The red line connects coefficient estimates of proximity bins with view, obtained by interacting the proximity bins, the binary posttreatment indicator, and the visibility indicator (i.e., equals 1 if with site view). The number of observations (N) in this analysis is 8,303,074, excluding singleton observations on the census-tract by year level. The 95% CIs are constructed with two-way clustered SEs at the census tract and year level. The control group is properties in the 5-to-6-mile proximity bin.

type includes properties over five acres with residential structures (hereafter "large-lot homes"), where LSSPV effects may include both residential amenity and land use value impacts. Within the analysis of each property type, we further investigate the impact heterogeneity across a range of dimensions, including rural–urban status, census region, lot size, county political leaning, median household income, solar site scale, site historical land use, state siting regulation, among others. To make sure our estimates are not specific to the five-acre segregation criterion, we conducted robustness checks in *SI Appendix*.[‡]

1. Results

1.1. LSSPV Impact on Residential Home Value. We first present the results for residential properties under five acres, which include approximately 8.3 million property transactions within a 6-mile radius of LSSPV sites from 15 y before the installation of each site through 2020. Further analytical details are provided in *Data and Methods*.

1.1.1. Residential proximity and visibility. We first use distance decay specifications within the DID framework (see Section 3.5 for model details) to decide the proper treatment variable, assuming solar site exposure is determined by proximity and visibility. The view-specific distance decay results (Fig. 2) show that proximity is the major driver of the negative residential value impact. We find that, without LSSPV view, LSSPV proximity reduces residential sales price by up to 7.2% within a 0.5-mile radius, and the bin-specific estimates gradually decrease with distance and remain statistically significant up to 3 miles from the LSSPV site. Having LSSPV in the viewshed of a home incurs slightly more negative effects (i.e., up to 7.9% within 0.5 miles) compared to the pure proximity effects,[§] and the bin-specific effects also diminish with distance. Beyond 3 miles, both the proximity effect and the visibility effect become indistinguishable from zero, suggesting that visibility does not independently generate negative impacts in the absence of proximity.

1.1.2. Residential treatment—site within 3 miles. As shown in Table 1 column (1), when examining the average treatment effect of proximity within 3 miles (regardless of visibility), the estimate is 4.8% and statistically significant at the 5% level. We further investigate the interaction between proximity and visibility in column (2). When the solar site is visible and within 3 miles, property values, on average, decrease by about 5.2%. The corresponding effect of an invisible site is estimated at 4.6%. While both estimates are statistically significant at the 5% level, a statistical test shows that the difference between them is not significant at all (test *P*-value = 0.746), indicating that site visibility may not impose a significant additional average effect beyond proximity and supporting the validity of proximity-based specifications in prior studies (e.g., refs. 8 and 9). We also checked an alternative specification that excludes no-view properties within the 3-mile radius in column (3) of Table 1, which provides a similar interaction effect of visibility and proximity. These average effect analyses, combined with the distance decay results, suggest that site proximity alone largely drives the residential home effect. Consequently, site proximity within a 3-mile radius [as presented in Table 1 column (1)] serves as the principal treatment variable, representing LSSPV exposure, in subsequent event study and heterogeneity analyses. Examining the sensitivity of estimates to alternative control group specifications in *SI Appendix*, Table S6, we find that the interaction effect of visibility and proximity remains robust across the board, while the pure proximity effect becomes insignificant in some of the alternative

Table 1. DID Estimates for Residential Homes

	(1)	(2)	(3)
	ProxT	ProxT × ViewT	ProxT × ViewT
ProxT	−0.076**		
	(0.022)		
β_3: ProxT × Post	−0.048*		
	(0.020)		
ProxT × 0.ViewT		−0.078**	
		(0.022)	
ProxT × 1.ViewT		−0.070**	−0.044
		(0.023)	(0.029)
$\beta_3^{no\_view}$: ProxT × 0.ViewT × Post		−0.046*(0.020)	
β_3^{view}: ProxT × 1.ViewT × Post		−0.052*	−0.046+
		(0.020)	(0.023)
N	4975808	4975808	2444983
Covariates	Yes	Yes	Yes
Census Tract × Year	Yes	Yes	Yes

Test (H_0: $\beta_3^{no\_view} = \beta_3^{view}$): z-Statistic = 0.324 *P*-value = 0.746

Note: In Column (1), ProxT, standing for site proximity below 3 miles, is used as the treatment. In Column (2), proximity without view (ProxT×0.ViewT) and proximity with view (ProxT×1.ViewT) are used as treatment. In Column (3), properties that satisfy ProxT = 1 and ViewT = 0 are excluded. β_3s represent the treatment effects specified in Section 3.5.1. SE, two-way clustered at census tract and year level, are reported in parentheses: $^{+}P < 0.1$, $^{*}P < 0.05$, $^{**}P < 0.01$, $^{***}P < 0.001$. Census tract by year fixed effects and property-level covariates are included in all specifications but not displayed. The control group is properties in the 5-to-6-mile proximity bins of the LSSPV sites, and properties located within 3 to 5 miles from the LSSPV sites are excluded. The number of observations, N, is calculated excluding singleton observations on the census-tract by year level. The coefficient for Post is omitted due to collinearity with fixed effects.

[‡]The results are presented in *SI Appendix*, Table S8, which suggest that the main estimates are robust to alternative acreage thresholds for segregating the small-lot properties and large-lot properties (e.g., 5 miles to 0.3 miles for small-lot properties and 5 miles to 9 miles for large-lot properties). Therefore, the main conclusions of this study are not sensitive to changes in the five-acre threshold.

[§]As pointed out in the *Data and Methods* section below, our visibility measure potentially overrepresents the true visibility especially when the viewpoint and the target are close, limited by structural elevation data availability (36). This measurement bias introduces attenuation in the treatment variable, potentially leading to an underestimation of the visibility impact (and hence the difference between visibility and proximity impact in Fig. 2).

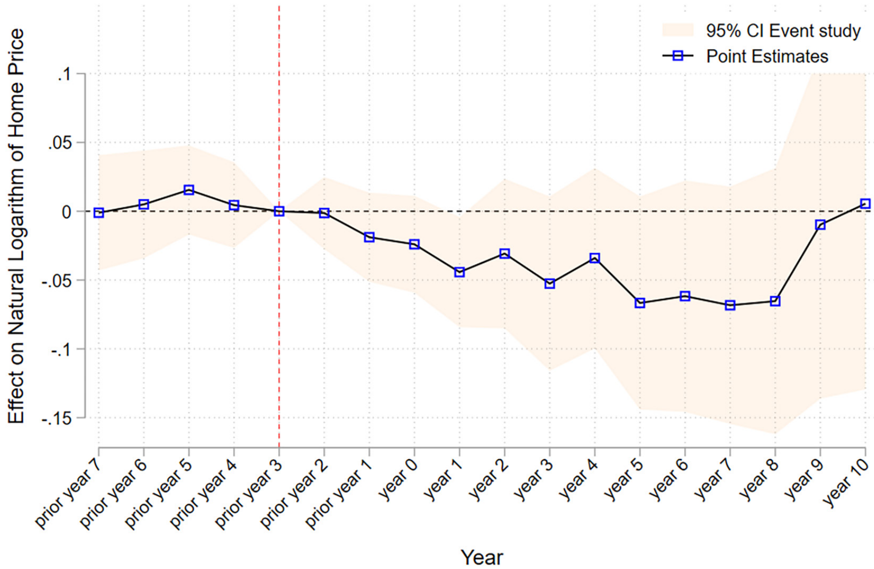

Fig. 3. Event study on residential home value. The treatment (LSSPV site within 3 miles) effect on residential home values is illustrated across different years relative to the year of LSSPV installation. The blue squares on the black line indicate the coefficient estimates, obtained by interacting the treatment variable with year indicators. The reference year is defined as 3 y before the LSSPV installation, and the control group is properties in the 5-to-6-mile proximity bin. The shaded areas represent the 95% CIs, constructed using two-way clustered SEs at the census tract and year level.

specifications. This implies that site visibility appears to reinforce the proximity effect in the sense that it improves the robustness of the home value effect estimate across various alternative control group specifications. To provide a comprehensive view of the proximity effect, we present both the specifications from column (1) and column (2) in the pretrend tests and robustness checks in the *SI Appendix*. Pretrend tests with placebo treatments in *SI Appendix*, Table S5 show that the parallel trend assumptions are satisfied for all specifications in Table 1. More robustness checks in *SI Appendix*, Tables S8 and *S9* confirm that all estimates in Table 1 remain consistent when applying alternative sample selection criteria based on acreage and the number of observations per tract-year cluster.

1.1.3. Residential event-study results. We explore the timing of the LSSPV exposure effect (i.e., site visible within 3 miles) based on an event study where the base year is specified as 3 y prior to the LSSPV installation[¶] (Fig. 3). The average negative price impact on residential homes is minor after the base year but becomes pronounced following the installation. The effect generally maintains its magnitude over time and fades after the ninth year postinstallation. There are potential explanations for the observed effect dynamics. Right after the base year, the gradual dissemination of the LSSPV site information may not have reached many home buyers or led them to fully realize the potential negative price impact of the site, but the installation event makes the impacts clear and manifested in the market. The diminishing effect after 9 y might come from the shrinking sample size as most of the LSSPV sites were developed after 2010. However, if the diminished effect is true, it does not necessarily imply that the negative amenity impacts disappear after 9 y since many of the negative impacts, such as soil erosion and dust pollution, may take a long time to manifest (14, 27, 28). A more plausible explanation of the faded price impact may be linked to residential sorting and demographic shifts (29–31), as individuals less concerned about LSSPV facilities move into the affected neighborhoods. This indirectly suggests that the negative price impact might be more closely related to psychological factors than to the amenities themselves, which will be explored further in subsequent analyses and discussions.

1.1.4. Residential Effect Heterogeneity. We explore the heterogeneity of LSSPV exposure effect on residential homes across various dimensions, as shown in *SI Appendix a*nd Fig. 4.[#] We observe noticeable heterogeneity across census regions, county political leaning, county median household income, and historical land use of the LSSPV sites. Statistical tests results are available in *SI Appendix*, Table S10. LSSPV sites in the Northeast region impose significantly more negative impacts than those in other regions. Heavily Democratic-leaning counties (over 65% Democratic votes in 2016) experience a positive LSSPV effect (+0.0374, insignificant), which is significantly different from more politically conservative counties (−0.0538, significant at the 5% level). Greenfield LSSPV development leads to a negative effect (−0.0466, significant at the 10% level), while brownfield redevelopments lead to a positive residential value effect (+0.225, significant at the 10% level), significantly different from the effect of Greenfield LSSPV.[||] Observed differences along other dimensions are not statistically significant. Moreover, we observe almost zero heterogeneity across different rural status, different lot sizes, different site capacities, and different levels of site visibility. A higher level of visual exposure ("High View" in Fig. 4) or directly facing the solar panels (i.e., in the south of the solar panels,

[¶]This approximately represents the time when some residents may become aware of the upcoming LSSPV site through permitting, contracting, community engagement, or other site preparation activities.

[#]We also investigate the heterogeneous pure proximity and visible proximity effects in *SI Appendix* Fig. S7. The results show that both effects have very similar heterogeneities as the main results in Fig. 4: the negative property value impact is significantly higher in more politically conservative counties, and brownfield sites may have a positive property value impact.

[||]Brownfields include sites such as hazardous waste facilities, abandoned contaminated areas, and inactive mines (53). Solar projects on brownfields often require site cleanup, which can reduce negative externalities and undesirability of these sites and positively affect property values. This aligns with Gaur et al. (54), who found that residents are willing to pay more for solar projects on brownfields, as these sites are otherwise undesirable. Meanwhile, respondents in Gaur et al. request compensation for solar project developed on greenfields, suggesting that they perceive brownfields as the more appropriate land type for LSSPV development than greenfields.

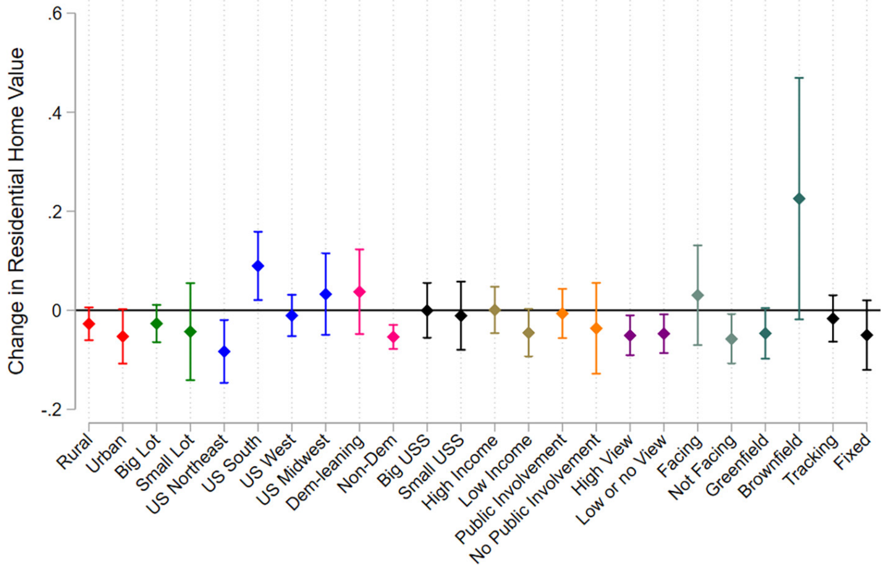

Fig. 4. Heterogeneous effects of LSSPV exposure by different dimensions. Diamonds are the point estimate of the effect of LSSPV on nearby residential home values based on DID models. The treatment is LSSPV within 3 miles, and the control group is properties in the 5-to-6-mile proximity bin of the LSSPV site. The 95% CIs of the estimates are shown as bars, having clustered SEs at the census tract and year level. Check *SI Appendix* for the details of all factors investigated here. More heterogeneity checks differentiating visible and invisible sites are available in *SI Appendix*, Fig. S7.

"Facing" in Fig. 4) does not lead to a more negative residential value effect, providing further evidence that more view exposure may not lead to significantly more negative impacts. While we lack direct data on glint and glare effects, indirect evidence suggests they may not be a primary mechanism, as we find no evidence to support that being exposed to a site with tracking systems (i.e., potentially more susceptible to glare impacts, "Tracking" in Fig. 4) or facing the solar panels lead to more negative impacts. Instead of visual levels or details, impacts appear to stem from psychological factors, such as negative perceptions of industrialization and altered scenic views. These negative perceptions are expected to be amplified by conservative ideology or mitigated by progressive ideology, aligning with the empirical finding that more politically conservative counties are associated with more negative impacts.

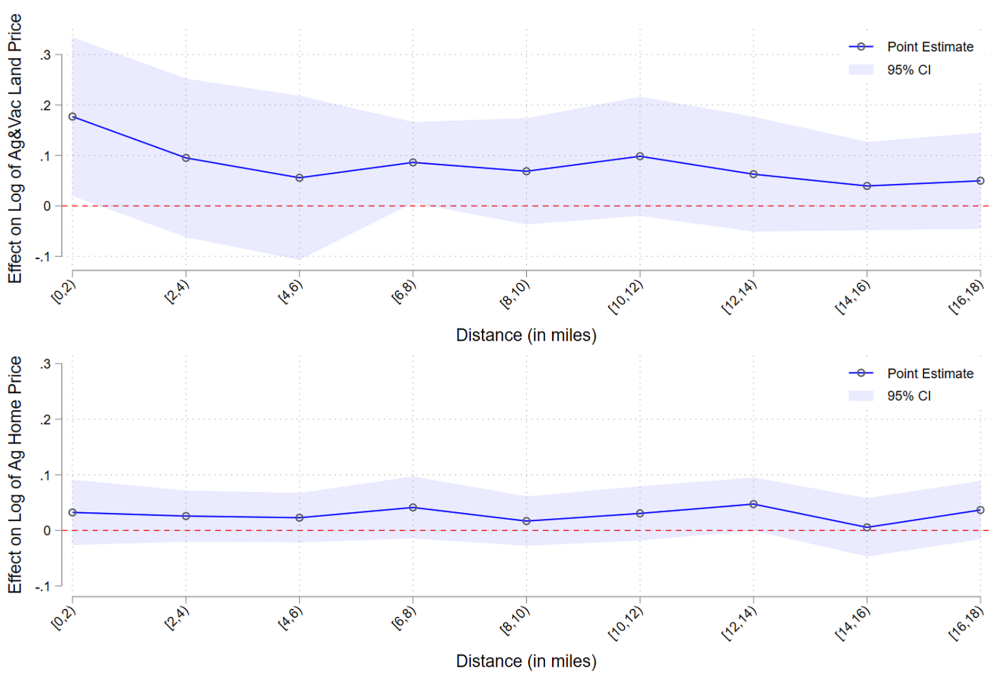

Fig. 5. Distance decay results for agricultural/vacant land and large-lot homes. The top subfigure shows estimates for agricultural and vacant land above five acres. The bottom subfigure shows estimates for large-lot homes, defined as properties over five acres with residential structures. The results show the value effects of LSSPV for a range of proximity bins, defined with 2-mile intervals. The blue line connects the coefficient estimates of proximity bins, obtained by interacting the proximity-bin indicators with the binary posttreatment indicator. The treatment groups are properties within these proximity bins, while the control group is properties within the 18-to-20-mile proximity bin. The 95% CIs are constructed with two-way clustered SEs at the county-site and year level.

1.2. LSSPV Impact on Agricultural Land Value. Our Ag-land analyses show that having LSSPV sites within 2 miles of agricultural or vacant land increases the sales price per acre by an average of 19.4%,[**] which is statistically significant at the 5% level (Fig. 5). The positive effect rapidly declines and becomes insignificant beyond 2 miles, similar to estimates in ref. 32. This positive effect is likely due to the demand increase from potential solar leases, as further expansion of existing LSSPV sites is less costly than constructing new sites and likely involve nearby agricultural or vacant land. Pretrend tests in *SI Appendix,* Table S5 show that the parallel trend assumptions are satisfied. Robustness checks in *SI Appendix,* Table S7 suggest that our main ag-land estimate is robust against different control group selection criteria. Event-study results in *SI Appendix,* Fig. S5 show that the positive land value effect manifests 3 y after the site installation and fades away 6 y later. *SI Appendix,* Fig. S6 presents our analysis of heterogeneous ag-land effects. We find that LSSPV sites of larger than-median scale have virtually zero effect on land value, while sites of smaller scale display a positive effect on land value (significant at the 10% level). Considering that smaller sites have a larger potential for expansion, this observation seems to confirm our speculation that the nearby land value increase is mainly driven by the potential of future solar lease. We also find that agricultural or vacant lots of large acreage bear virtually zero effect while smaller lots show a significantly (at the 5% level) positive effect. However, these differences are not statistically significant. More robustness checks in *SI Appendix,* Table S8 suggest that our land value estimates remain consistent when applying alternative sample selection criteria based on acreage. Finally, robustness checks in *SI Appendix,* Table S9 reveal that when focusing solely on county-site-year clusters containing more than a few sales, the land price effect of LSSPV rises dramatically, reaching 86.1% when excluding less-than-20-land-sales clusters (corresponding to a coefficient of 0.621). Given that we have excluded sales of land hosting LSSPV sites, the mechanism behind this substantial effect on land prices remains unclear but warrants further investigation.

1.3. LSSPV Impact on Large-Lot Home Value. Our empirical results show that LSSPV sites have a dual effect: they decrease residential property values via reduced residential amenity, while simultaneously increasing nearby land prices due to enhanced land use potential. For large-lot residential homes with over five acres of land, we expect the LSSPV to impact property values through both channels. Our distance decay analysis (Fig. 5, *Bottom*) suggests that the overall LSSPV impact on large-lot home price is close to zero and statistically insignificant for all nearby proximity bins. Robustness checks in *SI Appendix*, Tables S8 and S9 confirm that these large-lot-home estimates remain small and insignificant when applying alternative sample selection criteria based on acreage and the number of observations per tract-year cluster. Therefore, the LSSPV property value impacts via amenity reduction and increased land use potential seem to offset each other in residential homes with over five acres of land.

2. Discussion

This study provides a comprehensive nationwide assessment of the externalities associated with LSSPV installations in the United States focusing on their impacts on property values. We leverage a rich property transaction dataset with detailed geospatial information of LSSPV sites to estimate the effects on both residential properties and agricultural/vacant land. We apply advanced geospatial methods to overcome computational challenges and develop a comprehensive nationwide database on LSSPV visibility. Our findings reveal that LSSPV installations negatively affect the value of residential properties located within 3 miles, while increasing prices for agricultural and vacant land within 2 miles. Moreover, when the impacts through reduced residential amenity and increased land use potential coexist, the LSSPV effect on large-lot homes is indistinguishable from zero. We also explore the dynamics and heterogeneities of the local property value effects of LSSPV.

Our analyses and heterogeneity checks indicate that a nearby solar site may act as a stigmatizing nuisance (i.e. a psychological disamenity, see refs. 15, 16, 33) and 34). Evidence supporting this claim includes the minimal variation in effects across different levels of site visibility, in effects across properties to the south and to the north of the site, and in effects across sites with different tracking systems, as they suggest that the view details of solar sites (including view extent, the exact view composition, and potential difference in glare effects) do not significantly impact residential values. The negative impact on nearby residences appears to operate primarily through psychological channels rather than through the degree of visibility or specific visual details. Considering disamenities other than visual impact, the scale of the site likely results in different disamenity levels and impacts, but this is also not observed (i.e., "Big USS" vs. "Small USS" in Fig. 4). One explanation can be linked to negative perceptions that solar sites are industrial/commercial uses that alter rural land use and scenic views (15). The disparities in effects between brownfield and greenfield sites align with this mechanism. Another piece of evidence is the significantly higher property value loss in more conservative counties compared to Democratic-leaning counties. This disparity is likely due to solar sites being more aligned with progressive values prevalent in Democratic-leaning counties and less frequently associated with negative perceptions. However, we cannot entirely rule out causal channels related to actual disamenity variations. First, our nationwide analysis may obscure heterogeneities under certain conditions – for example, sites with a larger scale may have a stronger negative effect in the Northeast but a weaker one in the West, potentially canceling out in a pooled sample. Second, unexplored physical channels, such as vegetation and soil management practices (e.g., refs. 9 and 27), might also contribute to the negative LSSPV impact on residential values.

Our findings highlight the complex interplay between the benefits and costs of LSSPV development. In *SI Appendix,* Table S11, we performed a back-of-the-envelope calculation to estimate the benefits and costs of LSSPV solar sites included in our analysis, including the mitigation value (i.e., avoided social cost of carbon emission), the appreciation of nearby agricultural or vacant land value, the value loss of nearby residential properties, and the agricultural production loss on land utilized for hosting LSSPV. The results suggest that the assessed benefits of existing LSSPV significantly outweigh the assessed total costs. The carbon mitigation benefit is the major benefit (about \$22.2 billion annually), while the loss in residential home value is the dominant cost (about -\$4.1 billion annually). Therefore, property value losses constitute a major proportion of negative externalities of LSSPV. While the expansion of solar energy is crucial for the renewable energy transition, it is imperative to address the localized externalities to ensure equitable outcomes for affected communities. Quantitative evidence, such as that generated by this study, can inform policymakers and stakeholders in designing compensation mechanisms and siting strategies that mitigate negative impacts while promoting the broader adoption of solar energy.

[**]The coefficient estimate is 0.177, which reflects the effect on the logarithm of price. When this is converted to the actual proportional price effect, the result is $e^{0.177} - 1 = 19.4\%$.

To illustrate how our results or similar studies could be used to develop a community compensation plan, we design a prototype evidence-based community compensation plan for a site proposal in (*SI Appendix,* Fig. S12). First, property value impact studies should be carefully conducted with empirical data from comparable solar sites (e.g., similar size, similar demographics, in counties or states of similar regulations, etc.), where the effect of distance decay, dynamics, and heterogeneities across a wide range of dimensions should be analyzed. The sample choice of LSSPV sites needs to balance site similarity and statistical power of analysis. Second, based on the property value study, compensation specifics should be decided for different properties in the neighborhood. Taking our main results as an example, compensation rates could be set at 5.2% of the annualized property value for 10 y for residential homes within 3 miles of the LSSPV site with a site view, 4.8% for those without a view, and 19.4% of annual agricultural land rental costs[††] for 4 y for leasing farmers within 2 miles. Third, the community compensation plan can involve communication with stakeholders ahead of the permitting process, and stakeholders' input should be involved in the revision process before reaching a final plan. A comprehensive compensation plan should also consider local externalities that might not visibly manifest in property prices. We would like to stress that the specific community compensation plan developed based on our nationwide study here should be merely taken as an example, and we recommend conducting targeted studies to determine appropriate community compensation plans for a specific LSSPV site.

3. Data and Methods

The analysis primarily utilizes data of three categories: The US LSSPV data, the real estate transaction and assessment records, and geospatial data.

3.1. LSSPV Data. The LSSPV data acquired from the US Large Scale Solar Photovoltaic Database (USPVDB) (35) contain 3,699 LSSPV facilities investigated in the study. This dataset provides detailed information on LSSPV site footprint, area, capacity, and installation year, spanning from 1986 to 2021 (*SI Appendix,* Fig. S1 shows the total acreage developed per year, and *SI Appendix,* Table S1 shows the summary statistics of LSSPV projects). The facility polygons are digitized along the boundaries of the solar arrays, within an accuracy of 10 m.

3.2. Property Transaction. The property data are purchased from CoreLogic through a data agreement. CoreLogic data contain comprehensive information on property and transactions from the whole United States and enables researchers to work on property-level research questions. We developed a process to exclude non-arm's-length transactions (i.e., purging price outliers, foreclosure sales, multiple sales, sales between relatives, sales involving institutional buyers or sellers, and others as detailed in *SI Appendix*) so that our analyses only include transactions reflecting fair market values. The transaction prices are adjusted for inflation to reflect their values in 2017 dollars using the Consumer Price Index data from the US Bureau of Labor Statistics. We also exclude potential home flipping events by removing transactions of the same property that occur within 120 d of each other. As the majority of LSSPV sites have been developed within the past decade, we keep transactions up to 15 y before the installation of nearest LSSPV to make the time frame generally centered around the LSSPV development.

The final dataset for analysis comprises both single-family residential properties and agricultural or vacant land, spanning 40 states[‡‡] from 1993 to 2020. To avoid the potential impact from market disequilibrium, we drop observations during the Great Recession (i.e., 2008 to 2010). *SI Appendix,* Tables S2–S4 show the summary statistics of residential homes, agricultural and vacant land, and large-lot homes, respectively. *SI Appendix,* Figs. S2–S4 illustrate the distribution of post-LSSPV-installation transactions of residential homes, agricultural or vacant land, and large-lot homes, respectively, across different proximity bins.

3.3. Geospatial Data. The geospatial data consist of a collection of geographic layers obtained from the US Census Bureau TIGER/line geodatabase (USCB TIGER) and US Energy Information Administration (EIA), which includes shapefiles of primary roads, transmission lines, and metropolitan areas. To support heterogeneity analyses, we also collected data on median household income, median land values, political leanings, and state-level siting policies, among other factors (see *SI Appendix* for details).

To acquire solar site proximity and other (dis)amenities, we generated geographic variables that represent the Euclidian distance between a property and the boundary of the nearest five solar sites, transmission line, primary road, and metropolitan area. The geographic variables were then matched with the property data. To alleviate identification concerns that attributes of control observations (i.e., properties far away from sites) might considerably deviate from treated observations (i.e., properties with solar site exposure), we only kept residential homes that are less than or equal to 6 miles away from the nearest solar sites. For properties above five acres (i.e., agricultural land or large-lot homes), we use a 20-mile radius inclusion criterion due to the general low density and low transaction volumes of such properties. The final sample includes 8.3 million transactions for residential homes, 68 thousand transactions for agricultural or vacant land, and 416 thousand transactions for large-lot homes.

3.4. Visibility Analysis. We establish a visibility database for LSSPV across the continental United States and investigate the property value effect of LSSPV visibility. We calculate the visibility from residential properties to large-scale solar sites within 6 miles. This visibility analysis proceeds in three steps. First, we acquire Digital elevation models (DEMs) of the continental United States from the Shuttle Radar Topographic Mission (SRTM) produced by NASA.[§§] Our analysis uses the 2018 version of SRTM DEMs at a resolution of 90 m by 90 m. The DEMs employed reflect terrain elevation but may not capture structures (e.g., houses or trees), and hence could overstate visibility especially when the viewpoint and the target are close (36). Nonetheless, the employed DEMs are the best available public data for our analysis, as structural elevation data (e.g., Light Detection and Ranging, or LiDAR, data) are not available for most solar sites and their neighborhoods.

Second, we calculate the viewsheds from solar sites to decide the areas from which the sites are visible, utilizing the duality of vision following ref. 21 (i.e., if and only if viewpoint A has a view on target B, a viewpoint on B has a view on target A). This approach greatly reduces computational effort since the number

[††]Note that this compensation assumes that the land price increase will induce a similar change in land rent costs. If land rent data is available, it could be used as the outcome in a similar DID study to decide the land rental cost impact of LSSPV site, which could serve as the baseline of the compensation to leasing farmers.

[‡‡]The other ten states (i.e., Alaska, Hawaii, Idaho, Kansas, Louisiana, Maine, Mississippi, Montana, Utah, and Wyoming) are excluded from the final analysis due to the absence of LSSPV sites, a lack of available transactions near LSSPV sites, or their non-continental status.

[§§]DEMs provide crucial information on the ground topography of the study area. The Shuttle Radar Topographic Mission by NASA employs remote sensing technology to gather laser light measurements of the earth's surface. The mission started in 2000, with a goal to create the first near-global topographical map of Earth and collect data on nearly 80 percent of the planet's land surfaces. Data are available at https://srtm.csi.cgiar.org/.

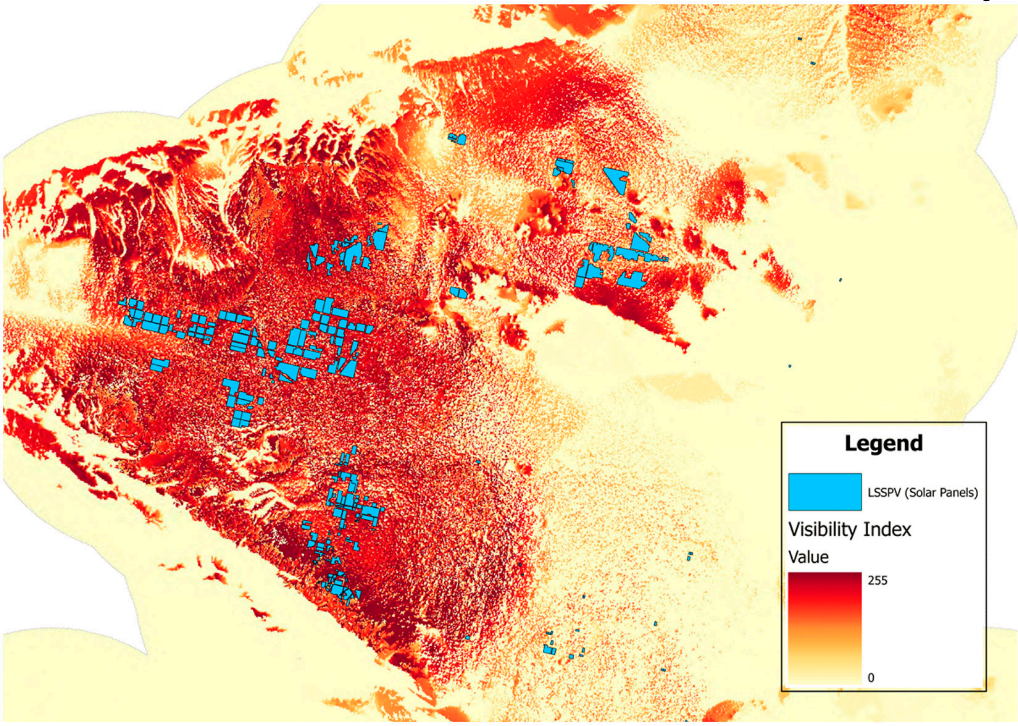

Fig. 6. Surface of Visibility Index. The visibility index measures the number of visible perimeter points of nearby solar sites. Intuitively, the red color denotes regions with solar view, and regions in darker red can see a larger area of solar panels.

of solar sites (3,699) is much smaller than the number of properties (about 5.9 million). Unlike the wind turbines that require height specifications for accurate viewshed analyses, LSSPV sites span broad areas, necessitating a proper way to account for partial views of a large solar site. Specifically, we set viewpoints along the perimeter of each site, where the viewpoints are defined with a random start point, an interval distance D, and a height of two meters. In practice, D is set at 500 m to balance the computation workload and the accuracy of partial view accounting.

Third, we aggregate the viewsheds from all site perimeter viewpoints and overlay the aggregated viewshed layer with properties to calculate the visibility variables. The aggregation of viewsheds will generate the visibility index (Fig. 6) for each geographic unit defined by the raster resolution (90 m by 90 m). Overlaying with the property layer, the visibility index will represent the number of perimeter viewpoints that can see a property, or the number of solar site perimeter points that the property has view on based on the duality of vision. This property-specific visibility index quantifies the extent of solar site visibility for each property and can be converted into a binary visibility variable that serves as the treatment variable in a DID model. For more details of the visibility analysis, refer to *Visibility Analysis* Details section in *SI Appendix*.

3.5. Econometrics: Property Value Effect Models. Previous studies have used econometric models to analyze and identify a variety of characteristics that could consistently influence property values, such as the productivity of the farmland (e.g., ref. 37), the influences of urbanization (e.g., ref. 38), and environmental factors (e.g., refs. 39–41). To estimate the impact of solar projects on nearby property values, it is crucial to control for potential confounders. We employ a DID approach to investigate the effects of LSSPV installation on nearby property values. Intuitively, this approach compares the change in property values before and after installation for properties close to the LSSPV site against the value change for properties farther away but still within the defined vicinity.

3.5.1. Analyses for residential homes. The general DID framework of our residential home study is as follows:

$$\ln(P_{it}) = \beta_0 + \beta_1 Post_{it} + \beta_2 T_i + \beta_3 Post_{it} \times T_i + \delta_k \sum_{k=1}^{K} X_{it}^k + \gamma_k \sum_{k=1}^{K} (Post_{it} \times X_{it}^k) + \tau_{ct} + \varepsilon_{it}. \quad [1]$$

In Eq. **1**, each observation corresponds to a transaction of residential home i that occurred in year t, with the dependent variable being the natural logarithm of transaction price $\ln(P_{it})$. $Post_{it}$ is a binary indicator that denotes whether the transaction of residential home happened after the LSSPV installation. T_i is the binary indicator that denotes whether a residential home was assigned to a treatment group, and the exact definition of treatment is explained below. The coefficient β_3 associated with the interaction term between $Post_{it}$ and T_i captures the impact of LSSPV installation on the outcome variable, which resembles a proportional change in the residential home prices. Previous studies show that the proximity to transmission lines could have an impact on the value of nearby property (42), and this impact could change after an LSSPV installation in the vicinity (20). To account for housing and lot characteristics that could affect home values and the estimation of β_3, we include property-level control variables X_{it}^k and $Post_{it} \times X_{it}^k$ (43, 44), where X_{it}^k include total bedroom number, total bathroom number, building age, and natural logarithms of distances to the nearest transmission line, the nearest primary road, and the nearest metropolitan area. To absorb the time-varying external location-specific shocks in the housing market, we incorporate fixed effects on the census tract by year level, denoted as τ_{ct}. All SE are two-way clustered at the census tract and year level.

To detect the proper site-proximity treatment in the average effect models (i.e., Eq. **1**), we employed a distance decay version of the DID approach, as shown in Eq. **2**. The distance decay study uses proximity intervals (T_i^m, $\forall m \le M-1$) as the treatment variables instead of a single binary treatment (as T_i in Eq. **1**). The distance-decay model shown in Fig. 2 uses 0.5-mile intervals from 0 to 6 miles, with properties in the 5 to 6 mile ring (i.e., T_i^M) serving as the control group. To investigate the role of visibility, we further interact the proximity intervals with a binary visibility variable to produce the results in Fig. 1 (i.e., the treatment variables become $T_i^m \times 1(View=1)$ and $T_i^m \times 1(View=0)$). The model specifications in Eq. **2** are identical to Eq. **1** except for differences in the treatment variables,

$$\ln(P_{it}) = \beta_0 + \beta_1 Post_{it} + \sum_{m=1}^{M-1} \beta_2^m T_i^m + \sum_{m=1}^{M-1} \beta_3^m Post_{it} \times T_i^m + \delta_k \sum_{k=1}^{K} X_{it}^k + \gamma_k \sum_{k=1}^{K} (Post_{it} \times X_{it}^k) + \tau_{ct} + \varepsilon_{it}. \quad [2]$$

Based on the proximity cut-off point suggested in the distance decay results, we specify a proximity treatment (i.e., results suggest properties within 3 miles) for the average treatment model in Eq. **1**. Moreover, we can test the average treatment effect of the interaction between visibility and proximity, by slightly modifying Eq. **1** to allow for two treatment groups [i.e., effects shown as β_3^{view} and $\beta_3^{no\_view}$ in Table 1 column (2)]. The empirical results of these specifications decide the appropriate treatment to use for subsequent studies, where the control group specification will also be consistent with the exploratory specifications.¶¶ Details of subsequent event study and heterogeneity analyses are presented in *SI Appendix*.

Our DID model relies on the assumption that the LSSPV siting process is independent of the price trends over time conditional on the covariates (i.e., the parallel trends assumption). We conduct pretrend tests with placebo treatments by setting a pseudo-post variable mimicking a fake installation event 6 y before the actual installation and dropping observations that are actually treated after the actual site installation. Null effect estimates from the placebo tests support the plausibility of the parallel trends assumption. Moreover, the event study model could also display pretreatment effects where pretreatment trend differences would show up and suggest a violation of the parallel trends assumption.

3.5.2. Analyses for agricultural land and large-lot homes. We use a distance-decay model to detect the cut-off proximity for the treatment variable in the DID analysis for agricultural or vacant land and large-lot homes as the potential impact mechanism is related to site proximity. The ag-land distance-decay model is built on Eq. **2** with three key differences. First, the outcome variable is the natural logarithm of land price per acre. Second, the control variables X_{it}^k do not include house characteristics. Finally, based on the volume of ag-land transactions, the proximity intervals are selected every two miles from 0 to 20 miles, the fixed effects used are on the county-site (i.e., an interaction between county and the LSSPV site identifier)## by year level, and the SE are two-way clustered at the county-site and year level. We also conduct the event study and heterogeneity analyses using the treatment variable suggested by the ag-land distance-decay model. Furthermore, we conduct pretrend tests for the ag-land analysis to check the plausibility of parallel trends assumption. The large-lot-home analysis retains the outcome and control variables from the residential analysis while adopting the same proximity bins and fixed effects used in the ag-land analysis. More details of ag-land and large-lot-home analyses are provided in *SI Appendix*.

¶¶This is to say, if pure proximity with a 3-mile cut-off point is decided as the most meaningful treatment to use, the control group in the main average effect model will be properties within the 5-to-6-mile proximity bin. This would involve the exclusion of properties within the 3-to-5-mile bin from the analyses. The subsequent event study and heterogeneity analysis models will follow the same sample and covariate specifications as the main model.

##The site identifier is based on the nearest LSSPV site. If a group of properties are within a 20-mile radius of the same site and the site is the nearest site to all of them, they share the same identifier. They span a relatively large region, potentially covering more than one county. To control for both site-level and county-level shocks, we use the county-site by year fixed effects here.

Data, Materials, and Software Availability. Our replication package (https://github.com/Starfallchen/SolarViewHedonic) provides all code used in this study, including Stata and Python code for raw data processing, geospatial variable processing, viewshed analysis, data aggregation, and estimation analysis (45). All analyses are conducted in Stata 18MP (https://www.stata.com/order/) (46) and Python 3.9.18 https://www.python.org/downloads/release/python-3918/) (47). The replication package also shares datasets that are from unrestricted data sources. The property transaction data are acquired from CoreLogic Solutions, LLC (https://www.corelogic.com/360-property-data) (48). Restricted by contract with CoreLogic, all variables derived from raw CoreLogic data will not be shared. To replicate our study, we recommend acquiring CoreLogic national-level property data with transactions from 1993 to 2020 and applying the data processing code in the replication package. Other raw data are from publicly available sources. The large-scale solar site data are available at the US Large Scale Solar Photovoltaic Database webpage: https://eerscmap.usgs.gov/uspvdb (49). Digital Elevation Models in the viewshed analysis are produced by NASA's Shuttle Radar Topographic Mission and available at https://srtm.csi.cgiar.org (50). Geospatial data on states, counties, census tracts, primary roads, and metropolitan areas are from US Census Bureau TIGER/line geodatabase, available at https://www.census.gov/geographies/mapping-files/time-series/geo/tiger-geodatabase-file.html (51). Geospatial data on transmission lines are obtained from US Energy Atlas hosted by Energy Information Administration, available at https://atlas.eia.gov/search (52). Data for heterogeneity analysis are drawn from multiple public sources, with details described in the *SI Appendix*.

ACKNOWLEDGMENTS. We gratefully acknowledge financial support from the Sustainable Agricultural Systems Grant 2019-68012-29904 and Hatch projects 7006196, 7006059, and 1024040 from the United States Department of Agriculture National Institute of Food and Agriculture. We sincerely thank editor Catherine Kling and two anonymous reviewers for their insightful and valuable feedback. Property data were acquired from CoreLogic. The results and opinions are those of the author(s) and do not reflect the position of funding institutions.

Author affiliations: [a]Department of Agricultural and Applied Economics, Virginia Polytechnic Institute and State University, Blacksburg, VA 24060; and [b]Department of Environmental and Natural Resource Economics, University of Rhode Island, Kingston, RI 02881

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Siting Board Post-Hearing 1-5:

Explain whether approval from Environmental Protection Agency is required for construction of this project.

Response: Barrelhead Solar does not anticipate any required approvals from the U.S. Environmental Protection Agency for the construction of the Project.

Witness: Trudie Grattan

Siting Board Post-Hearing 1-6:

Describe Barrelhead Solar's initial contact with local residents regarding leasing property for this Project. Include the date(s) when lease agreement(s) were signed with the participating landowner(s) for this project.

Response: The lease agreement with the participating landowner was signed on September 25, 2020 (see Application, Appendix D). The previous development company contacted other neighboring landowners around this time; however, Barrelhead Solar does not have any responsive documentation of these communications.

Witness: Trudie Grattan

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY STATE BOARD
ON ELECTRIC GENERATION AND TRANSMISSION SITING

In the Matter of the Application of Barrelhead Solar, LLC for a Certificate of Construction for an approximately 54-Megawatt Merchant Electric Generating Facility in Wayne County, Kentucky pursuant to KRS 278.700, et seq., and 807 KAR 4:110	)))	**Case No. 2025-00177**

CERTIFICATION

This is to certify that I have supervised the preparation of Barrelhead Solar, LLC's responses to the Siting Board Staff's Post-Hearing Request for Information and that the responses on which I am identified as a sponsoring witness are true and accurate to the best of my knowledge, information, and belief after reasonable inquiry.

3/2/26
Date

Richard Kirkland

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY STATE BOARD
ON ELECTRIC GENERATION AND TRANSMISSION SITING

In the Matter of the Application of Barrelhead Solar, LLC for a Certificate of Construction for an approximately 54-Megawatt Merchant Electric Generating Facility in Wayne County, Kentucky pursuant to KRS 278.700, et seq., and 807 KAR 4:110	)))	**Case No. 2025-00177**

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This is to certify that I have supervised the preparation of Barrelhead Solar, LLC's responses to the Siting Board Staff's Post-Hearing Request for Information and that the responses on which I am identified as a sponsoring witness are true and accurate to the best of my knowledge, information, and belief after reasonable inquiry.

3/3/2026
Date

Signed by:
Trudie Grattan
C0283142D8E64E3...
Trudie Grattan