**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

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| **IN THE MATTER OF THE PETITION BY CAVALRY ENERGY CENTER, LLC FOR CERTAIN DETERMINATIONS BY THE COMMISSION WITH RESPECT TO ITS JURISDICTION OVER PETITIONER'S ACTIVITIES AS A GENERATOR OF ELECTRIC POWER** | **)<br>)<br>)<br>)<br>)<br>)<br>)** | **CAUSE NO. 45474** |

**<u>CAVALRY ENERGY CENTER, LLC'S QUARTERLY REPORT: SECOND QUARTER 2022</u>**

This Quarterly Report ("Report") is filed as required by the Commission's Order in this Cause issued on May 26, 2021. This Report provides the required information to the extent such information is known and available. The requested information is as follows:

**(1) Any changes to the information provided in the Initial Report.**

The Initial Report is updated as follows:

**(9) Current estimate of the engineering/construction timeline and critical milestones for the Facility.**

Currently, the expected timeline for the Facility is as follows:

Oct. 2022: Start of Construction
Jan. 2024: Backfeed Available Date
Feb. 2024: Sync Date
May 2024: Commercial Operation Date

**(2) Any reports of Interconnection System Impact Studies not previously submitted to the Commission.**

The Phase II and Phase III System Impact Studies for queue position J1067 are provided with this Report. All other system impact studies for J1067 have previously been provided.

Interconnection studies for J1810 are not yet available.

**(3) Copy of the GIA as filed with the FERC.**

The GIA for J1067 has been executed and filed with FERC. A copy of the signed GIA was included with the Fourth Quarter 2021 Report.

The interconnection agreement for J1810 is not yet complete.

**(4) Notice of the establishment of an independent financial instrument, including its form and amount.**

In accordance with the Road Use Agreement executed with White County, a performance bond in the amount of $4,000,000 has been posted.

**(5) Achievement of construction milestones described in the GIA and such events as the procurement of major equipment, the receipt of major permits material to the construction and operation of the Facility, construction start-up, initial energization, and commercial operation.**

Not applicable. Cavalry Energy Center has not yet commenced construction.

**(6) When commercial operation is achieved, the nameplate capacity, term, and identity of the purchaser(s) for contracts then existing for utility sales, contingency plans (if any) detailing response plans to emergency conditions as required by state or local units of government, the interconnecting transmission owner and/or MISO, and the Facility's certified (or accredited) dependable capacity rating.**

Not applicable.

**(7) A copy of the decommissioning plan agreed to with White County.**

A copy of the decommissioning plan agreement with White County is attached to this Report.

## VERIFICATION

The undersigned, Anthony Pedroni, being first duly sworn upon his oath, states that he is the Vice President of Cavalry Energy Center, LLC; that he prepared or supervised the preparation of Cavalry Energy Center, LLC's Second Quarter 2022 Report; and that the statements contained therein are true to the best of his knowledge, information, and belief.

By: ______________________

**STATE OF FLORIDA** )
) **SS:**
**COUNTY OF PALM BEACH** )

Subscribed and sworn to before me, a Notary Public, in and for said State and County this 27 day of July, 2022.

Notary Public State of Florida
Jennifer Reynoso
My Commission HH 091424
Expires 02/21/2025

Signature

Jennifer Reynoso
Printed

My Commission Expires:
2-21-25

My County of Residence:
Palm Beach



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Respectfully submitted,

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Attorneys for Petitioner,
Cavalry Energy Center, LLC

**CERTIFICATE OF SERVICE**

The undersigned hereby certifies that a copy of the foregoing was electronically delivered this 29th day of July, 2022, to the following:

Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
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infomgt@oucc.in.gov

An attorney for Petitioner,
Cavalry Energy Center, LLC



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# MISO DPP 2018 April Central Area Study Phase II Report

03/18/2021

Revision 5

**MISO**
**720 City Center**
**Drive Carmel**
**Indiana 46032**
http://www.misoenergy.org

# Contents

## 1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2018 April Central Area Phase II (Central Area DPP II). The study was performed under the direction of MISO and reviewed by an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren (AMIL, AMMO, ATXI), Duke Energy (DEI), Hoosier Energy (HE), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), Southern Illinois Power Cooperative (SIPC), and Southern Indiana Gas & Electric Company (SIGE).

### 1.1. Project List

The original interconnection requests for DPP 2018 April Central Area had a total of 61 generation projects.

- Projects J957, J973, J983, J1012, J1017, J1018, J1019, J1035, J1066, J1080, J1116, J1118, and J1150 withdrew prior to the Phase I study.
- 48 generation projects with a combined nameplate rating of 9348.23 MW (ERIS) & 9348.23 MW (NRIS) were studied in Phase I.
- Projects J980, J985, J995, J1016, J1021, J1031, J1059, J1123, J1148, J1161 withdrew during Decision Point 1 (Prior to Phase II Kickoff).
- 39 generation projects with a combined nameplate rating of 7888.95 MW (ERIS) & 7838.95 MW (NRIS) were studied in Phase II.

The Central Area DPP Phase II study was kicked off on January 8th 2020 and consisted of the projects shown below in Table 1.

**Table 1: List of DPP April 2018 Central Area Phase II Projects**

| Project | Fuel Type | Transmission Owner | County | State | Service Requested | MW | POI |
|---|---|---|---|---|---|---|---|
| J955 | Gas | Ameren Transmission Company of Illinois | Sangamon County | IL | NRIS | 1165 | Austin Substation 345kV Bus |
| J956 | Solar | Ameren Missouri | Ralls County | MO | NRIS | 200 | Spencer Creek 345kV Substation |
| J968 | Wind | Northern Indiana Public Service Company | Jasper County,White County | IN | NRIS | 200 | Reynolds 345kV Substation |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J974 | Wind | Ameren Illinois | Fulton County,Peoria County | IL | NRIS | 250 | Mapleridge 345kV Switching Station |
| J976 | Solar | Ameren Missouri | Warren County | MO | NRIS | 300 | Montgomery - Enon 345kV Line Tap |
| J979 | Wind | Ameren Transmission Company of Illinois | Christian County | IL | NRIS | 170 | Pana Substation 345kV Bus |
| J987 | Solar | Ameren Missouri | Montgomery County | MO | NRIS | 100 | Montgomery 161kV Substation |
| J991 | Solar | Ameren Illinois | Clay County | IL | NRIS | 150 | Xenia 345kV Switching Station |
| J992 | Solar | Duke Energy Indiana | Cass County | IN | NRIS | 200 | Walton 230kV Substation |
| J993 | Solar | Indianapolis Power & Light Company | Boone County | IN | NRIS | 200 | Hortonville - Whitestown 345kV Line Tap |
| J994 | Solar | Ameren Missouri | Callaway County | MO | NRIS | 100 | Guthrie 161 kV Substation |
| J1022 | Wind | Ameren Illinois | McLean County | IL | NRIS | 150 | Weedman Substation 138kV Bus |
| J1025 | Wind | Ameren Transmission Company of Illinois | Knox County | MO | NRIS | 300 | Zachary - Maywood 345 kV Line Tap |
| J1026 | Wind | Ameren Missouri | Audrain County,Ralls County | MO | NRIS | 350 | Maywood - Spencer Creek 345 kV Line Tap |
| J1027 | Solar | Hoosier Energy | Pike County | IN | NRIS | 150 | Ratts 161 kV Substation |
| J1028 | Solar | Hoosier Energy | Pike County | IN | NRIS | 150 | Ratts - Victory 161 kV Line Tap |
| J1033 | Battery Storage | Ameren Missouri | Stoddard County | MO | NRIS | 50 | Stoddard - Morely 161 kV Line Tap |
| J1034 | Solar | Ameren Missouri | Stoddard County | MO | NRIS | 225 | Stoddard - Morley 161kV Line Tap |
| J1039 | Battery Storage | Ameren Missouri | Warren County | MO | NRIS | 50 | Enon - Montogomery 345kV Line Tap |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J1055 | Wind | Ameren Illinois | Mason County | IL | NRIS | 144 | Mason Substation 138 kV Bus |
| J1058 | Solar | Northern Indiana Public Service Company | Lake County | IN | NRIS | 200 | Schahfer-St. John 345kV Line Tap |
| J1063 | Solar | Duke Energy | Clinton County | IN | NRIS | 195 | New London - Frankfort 230kV Line Tap |
| J1067 | Solar | Northern Indiana Public Service Company | Jasper County,Pulaski County | IN | NRIS | 240 | Reynolds - Burr Oak 345kV Line |
| J1069 | Wind | Northern Indiana Public Service Company | Jasper County,Pulaski County | IN | NRIS | 200 | Reynolds 345kV Substation |
| J1074 | Solar | Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. | Gibson County | IN | NRIS | 200 | Francisco 138 kV sub |
| J1087 | Solar | Ameren Missouri | Scott County | MO | NRIS | 200 | Miner - Kelso 161 kV Line Tap |
| J1094 | Solar | Ameren Illinois | Washington County | IL | NRIS | 150 | Prest 138kV Switching Station |
| J1096 | Solar | Ameren Illinois | Saline County | IL | NRIS | 150 | Norris City North - Muddy 138 kV Line |
| J1102 | Solar | Ameren Illinois | Logan County | IL | NRIS | 70 | Fogarty 138 kV Substation |
| J1107 | Solar | Ameren Missouri | Cape Girardeau County | MO | NRIS | 200 | Kelso - Lutesville 345 kV Line Tap |
| J1111 | Solar | Southern Illinois Power Cooperative | Jackson County | IL | NRIS | 150 | Campbell Hill - Jackson 161 kV Line Tap |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J1112 | Solar | Northern Indiana Public Service Company | Kosciusko County | IN | NRIS | 150 | Leesburg 138kV Substation |
| J1115 | Wind | Ameren Illinois | Macon County | IL | NRIS | 200 | Latham - Oreana 345kV Line |
| J1139 | Solar | Ameren Illinois | Champaign County | IL | NRIS | 150 | Sidney Substation 138 kV Bus |
| J1145 | Solar | Ameren Missouri | Callaway County | MO | NRIS | 250 | Overton - (McCrede) - Montgomery 345 kV Line Tap |
| J1152 | Solar | Indianapolis Power & Light Company | Hancock County,Shelby County | IN | NRIS | 200 | Gwynneville - Sunnyside 345 kV Line Tap |
| J1180 | Solar | Ameren Illinois | Clark County | IL | NRIS | 75 | Casey West - Sullivan 345 kV Line |
| J1182 | Solar | Ameren Transmission Company of Illinois | Adair County | MO | NRIS | 250 | Zachary Substation 345 kV Bus |
| J1189 | Battery Storage | Duke Energy Indiana | Brown County,Martin County | IN | NRIS | 4.95 | Crane Solar 69kV Substation |

### 1.2. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2018 April Central Phase II reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

**Table 2: Total Cost of Network Upgrades for DPP 2018 April Central Phase II Projects**

| Project | ERIS Network Upgrades ($) | | | | NRIS Network Upgrades ($) | Interconnection Facilities ($) | | Shared Network Upgrades ($) | Total Network Upgrade Cost for Milestone Calculation ($) | M2 ($) | M3 ($) | M4 ($) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Thermal | Stability | Short Circuit | Affected System | Deliverability | TO Network Upgrades | TO – Owned Direct Assigned | | | | | |
| a | b | c | d | e | f | g | h | i | j = b+c+d+f+g+i | $4,000/MW | 10% of (j) from Phase I-M2 | (20% of (j) from Phase II)-M2-M3 |
| J955 | 0 | 0 | 0 | 26,318,100 | 0 | 884,000 | 1,346,000 | 0 | 884,000 | 4,660,000 | 0 | 0.00 |
| J956 | 0 | 0 | 0 | 0 | 8,734,641 | 1,170,000 | 1,626,000 | 0 | 9,904,641 | 800,000 | 9,725.10 | 1,171,203.10 |
| J968 | 0 | 0 | 0 | 0 | 0 | 1,102,243 | 810,385 | 0 | 1,102,243 | 800,000 | 0 | 0.00 |
| J974 | 0 | 0 | 0 | 4,777,168 | 0 | 1,596,000 | 1,092,000 | 0 | 1,596,000 | 1,000,000 | 0 | 0.00 |
| J976 | 0 | 0 | 0 | 0 | 5,265,682 | 4,906,500 | 494,000 | 0 | 10,172,182 | 1,200,000 | 0 | 834,436.40 |
| J979 | 0 | 0 | 0 | 3,275,500 | 0 | 4,042,000 | 1,519,000 | 0 | 4,042,000 | 800,000 | 0 | 8,400.00 |
| J987 | 0 | 0 | 0 | 0 | 1,801,909 | 831,000 | 1,229,000 | 0 | 2,632,909 | 400,000 | 0 | 126,581.80 |
| J991 | 0 | 0 | 0 | 298,000 | 0 | 2,391,000 | 1,199,000 | 0 | 2,391,000 | 800,000 | 0 | 0.00 |
| J992 | 0 | 0 | 0 | 0 | 0 | 4,509,448 | 1,474,438 | 0 | 4,509,448 | 800,000 | 0 | 101,889.60 |
| J993 | 0 | 0 | 0 | 0 | 0 | 16,350,303 | 569,301 | 0 | 16,350,303 | 800,000 | 242,500.00 | 2,227,560.60 |
| J994 | 0 | 0 | 0 | 0 | 1,426,381 | 896,000 | 762,000 | 0 | 2,322,381 | 400,000 | 0 | 64,476.20 |
| J1022 | 0 | 0 | 0 | 151,000 | 0 | 1,970,000 | 876,000 | 0 | 1,970,000 | 600,000 | 0 | 0.00 |
| J1025 | 17,500,764 | 0 | 0 | 0 | 0 | 9,957,000 | 1,024,000 | 0 | 27,457,764 | 1,200,000 | 2,948,233.00 | 1,343,319.80 |
| J1026 | 12,839,254 | 0 | 0 | 4,037,000 | 16,443,844 | 1,170,000 | 1,626,000 | 0 | 30,453,098 | 1,600,000 | 1,203,627.90 | 3,286,991.70 |
| J1027 | 0 | 0 | 0 | 0 | 10,155,153 | 717,200 | 2,919,300 | 0 | 10,872,353 | 600,000 | 507,695.50 | 1,066,775.10 |
| J1028 | 0 | 0 | 0 | 0 | 12,045,819 | 9,916,400 | 1,819,200 | 0 | 21,962,219 | 600,000 | 1,109,879.10 | 2,682,564.70 |
| J1033 | 0 | 0 | 0 | 436,000 | 335,070 | 3,054,500 | 310,500 | 0 | 3,389,570 | 200,000 | 236,568.10 | 241,345.90 |
| J1034 | 0 | 0 | 0 | 1,959,000 | 1,507,815 | 3,054,500 | 310,500 | 0 | 4,562,315 | 900,000 | 0 | 12,463.00 |
| J1039 | 0 | 0 | 0 | 0 | 877,614 | 4,906,500 | 494,000 | 0 | 5,784,114 | 200,000 | 409,074.40 | 547,748.40 |
| J1055 | 0 | 0 | 0 | 149,800 | 0 | 1,156,000 | 881,000 | 0 | 1,156,000 | 576,000 | 0 | 0.00 |
| J1058 | 0 | 0 | 0 | 6,280,000 | 0 | 24,582,234 | 1,246,580 | 0 | 24,582,234 | 1,200,000 | 300,000.00 | 3,416,446.80 |
| J1063 | 11,260,800 | 0 | 0 | 5,655,000 | 18,954,200 | 12,954,151 | 1,164,322 | 0 | 43,169,151 | 1,200,000 | 4,996,500.00 | 2,437,330.20 |
| J1067 | 0 | 0 | 0 | 0 | 0 | 22,831,834 | 1,226,902 | 0 | 22,831,834 | 960,000 | 540,000.00 | 3,066,366.80 |
| J1069 | 0 | 0 | 0 | 0 | 0 | 1,102,243 | 810,385 | 0 | 1,102,243 | 800,000 | 0 | 0.00 |
| J1074 | 0 | 0 | 0 | 2,531,000 | 26,798,315 | 1,216,300 | 588,804 | 0 | 28,014,615 | 800,000 | 1,805,435.30 | 2,997,487.70 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| J1087 | 0 | 0 | 0 | 656,000 | 1,319,532 | 8,322,000 | 621,000 | 0 | 9,641,532 | 800,000 | 935,301.00 | 193,005.40 |
| J1094 | 0 | 0 | 0 | 0 | 1,227,725 | 7,653,000 | 867,000 | 0 | 8,880,725 | 600,000 | 27,877.50 | 1,148,267.50 |
| J1096 | 0 | 0 | 0 | 0 | 0 | 6,422,000 | 621,000 | 0 | 6,422,000 | 600,000 | 200,000.00 | 484,400.00 |
| J1102 | 0 | 0 | 0 | 0 | 0 | 1,031,000 | 517,000 | 0 | 1,031,000 | 280,000 | 0 | 0.00 |
| J1107 | 0 | 0 | 0 | 447,000 | 1,358,952 | 9,813,000 | 1,024,000 | 0 | 11,171,952 | 800,000 | 704,358.70 | 730,031.70 |
| J1111 | 12,677,000 | 0 | 0 | 0 | 1,028,551 | 7,550,000 | 377,000 | 0 | 21,255,551 | 600,000 | 824,911.60 | 2,826,198.60 |
| J1112 | 0 | 0 | 0 | 0 | 0 | 4,326,378 | 1,166,956 | 0 | 4,326,378 | 800,000 | 0 | 65,275.60 |
| J1115 | 0 | 0 | 0 | 9,681,700 | 0 | 9,847,000 | 1,024,000 | 0 | 9,847,000 | 800,000 | 280,000.00 | 889,400.00 |
| J1139 | 0 | 0 | 0 | 41,861,500 | 0 | 290,000 | 1,017,000 | 0 | 290,000 | 600,000 | 0 | 0.00 |
| J1145 | 0 | 0 | 0 | 1,865,000 | 3,672,284 | 9,855,000 | 1,024,000 | 0 | 13,527,284 | 1,000,000 | 388,122.80 | 1,317,334.00 |
| J1152 | 0 | 0 | 0 | 3,909,000 | 2,181,818 | 0 | 0 | 0 | 2,181,818 | 800,000 | 242,500.00 | 0.00 |
| J1180 | 0 | 0 | 0 | 0 | 0 | 15,006,000 | 1,024,000 | 0 | 15,006,000 | 300,000 | 880,000.00 | 1,821,200.00 |
| J1182 | 3,659,982 | 0 | 0 | 2,098,000 | 0 | 1,367,000 | 1,227,000 | 0 | 5,026,982 | | 390,083.40 | 615,313.00 |
| J1189 | 0 | 0 | 0 | 0 | 284,936 | 0 | 0 | 0 | 284,936 | 20,000 | 8,493.60 | 28,493.60 |

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in Table 3. Shared Network Upgrades are shown in Table 4.

**Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)**

| Network Upgrade | TO | GI projects requiring upgrade for ERIS | GI projects requiring upgrade for NRIS | Cost of solution ($) | TO Self-fund |
|---|---|---|---|---|---|
| 2nd Maywood - Herleman 345kV Line | AMMO | J1026, J1025 | | 21,000,000 | Yes |
| 2nd Zachary 345kV Transformer and 2nd Zachary - Adair Line 161kV Line | AMMO | J1025, J1182 | | 13,000,000 | Yes |
| Campbell Hill - Bremen 69kV Rebuild | SIPC | J1111 | | 3,868,000 | No |
| Bremen - Evansville Tap 69kV Rebuild | SIPC | J1111 | | 3,396,000 | No |
| Evansville Tap - Sparta Tap 69kV Rebuild | SIPC | J1111 | | 3,492,000 | No |
| Campbell Hill 161kV : 69kV Transformer | SIPC | J1111 | | 1,921,000 | No |
| Coly - McKnight 500kV Terminal Upgrades | EES | | J1028, J1074, J1152 | 6,000,000 | No |
| Manson – Clarkshill 69kV Rebuild | DEI | J1063 | | 7,101,700 | No |
| Potato Creek – Manson 69kV Rebuild | DEI | J1063 | | 4,159,100 | No |
| Clarkshill – Thorntown 69kV Rebuild | DEI | | J1063 | 18,954,200 | No |
| 2nd J829 - Dresser 345kV Circuit | DEI | | J1189, J1027, J1028, J1074 | 45,500,000 | No |
| J1026 - Maywood 345kV Rebuild | AMMO | | J1094, J1111, J1107, J1087, J1033, J1034, J1026, J956, J994, | 45,000,000 | Yes |

| Network Upgrade | TO | GI projects requiring upgrade for ERIS | GI projects requiring upgrade for NRIS | Cost of solution ($) | TO Self-fund |
|---|---|---|---|---|---|
| | | | J1145, J987, J976, J1039 | | |

**Table 4: Shared Network Upgrades (Planning level cost estimates)**

| Shared Network Upgrade | TO | Higher queued projects associated with SNU | Study projects associated with SNU | Cost of solution ($) |
|---|---|---|---|---|
| No Projects Met Criteria – N/A | | | | |

**Note:**

1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.
3) Analysis performed shows there are two DPP-2018-APR Central projects for Shared Network Upgrade cost allocation.

## 2. FERC Order 827 Compliance Review

The Final Rule of FERC Order 827 "Reactive Power Requirements for Non-Synchronous Generation", which was issued June 16, 2016, stated that "Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation." As such, this Final Rule applies to all non-synchronous (wind, solar, and battery storage) projects included in the DPP 2018 April Central study cycle.

In this study, the power factor at the high-side of the generator substation for each inverter based project was calculated and reviewed. The study method is to set Qgen of each study project at its Qmax, solve the case, then record the P and Q injection on the high side of the generator substation to calculate the lagging power factor (injecting VAR to the system). The same process is then repeated by setting Qgen at Qmin to calculate the leading power factor (absorbing VAR from the system).

The results show that all projects meets the requirement to maintain 0.95 leading power factor, however, four projects do not meet the requirement to provide reactive power capability corresponding to 0.95 lagging power factor, as highlighted in red below in **Table 5**. Additional reactive support will be needed for these projects to meet the FERC requirement on reactive power capability prior to the completion of their GIA.

**Table 5: FERC Order 827 Review Results**

| FERC Order 827 | | | | Steady State (At Generator Substation) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | VAR Injection | | | VAR Absorption | | | | |
| Project | Pmax (MW) | Reactive Power Capability (MVAr) | Proposed VAR Compensation | P (MW) | Q (MVAr) | p.f. (pu) | P (MW) | Q (MVAr) | p.f (pu) | Meet FERC Order 827 Requirement? | Add'l VAR Needed (MVAr) |
| J1022 | 155.3 | 72.53<br>-66.14 | 2 x 10 MVAr Cap | 152.0 | 71.3 | 0.9053 | 150.3 | -105.8 | -0.8177 | Yes | |
| J1025 | 319.0 | ±104.835 | 1 x 50 MVAr Cap | 306.0 | 134.9 | 0.9150 | 301.8 | -149.9 | -0.8956 | Yes | |
| J1026 | 413.6 | ±135.924 | 1 x 65 MVAr Cap | 390.2 | 143.9 | 0.9382 | 379.0 | -247.4 | -0.8374 | Yes | |
| J1027 | 150.0 | ±25.144 | N/A | 148.1 | -4.6 | 0.9995 | 147.7 | -61.3 | -0.9236 | No | 53.3 |
| J1028 | 150.0 | ±25.144 | N/A | 147.8 | -4.8 | 0.9995 | 147.4 | -62.2 | -0.9213 | No | 53.4 |
| J0133 & J1034 | 275.0 | ±84.5 | 1 x 4 MVAr Cap | 270.9 | 37.2 | 0.9907 | 268.8 | -163.4 | -0.8545 | No | 51.8 |
| J1039 | 50.0 | ±30 | 1 x 4 MVAr Cap | 49.6 | 24.8 | 0.8944 | 49.3 | -45.0 | -0.7386 | Yes | |
| J1055 | 144.0 | 67.68<br>-80 | 1 x 7.5 MVAr Cap | 132.8 | 55.6 | 0.9224 | 125.6 | -128.5 | -0.6990 | Yes | |
| J1058 | 200.0 | ±97.6 | 1 x 4 MVAr Cap | 197.0 | 74.4 | 0.9355 | 195.6 | -134.9 | -0.8232 | Yes | |
| J1063 | 195 | ±95.2 | 2 x 4 MVAr Cap | 192.3 | 80.2 | 0.9229 | 191.2 | -129.4 | -0.8282 | Yes | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| J1067 | 240.0 | ±97.9 | 2 x 17 MVAr Cap | 236.9 | 91.6 | 0.9327 | 235.4 | -161.4 | -0.8248 | Yes | |
| J1069 | 200.0 | ±81.6 | 2 x 14 MVAr Cap | 196.6 | 80.8 | 0.9249 | 195.1 | -130.3 | -0.8316 | Yes | |
| J1074 | 200.0 | ±36.925 | N/A | 197.2 | -1.8 | 1.0000 | 196.6 | -84.8 | -0.9182 | No | 66.6 |
| J1087 | 200.0 | ±36.925 | N/A | 197.2 | 1.6 | 1.0000 | 196.6 | -84.7 | -0.9184 | No | 63.2 |
| J1094 | 150.0 | ±25.144 | N/A | 148.0 | -3.0 | 0.9998 | 147.6 | -58.5 | -0.9296 | No | 51.6 |
| J1096 | 150.0 | ±25.144 | N/A | 148.0 | -2.9 | 0.9998 | 147.5 | -59.7 | -0.9270 | No | 51.5 |
| J1102 | 70.0 | ±28.555 | 1 x 8 MVAr Cap | 68.7 | 27.5 | 0.9284 | 68.2 | -43.9 | -0.8409 | Yes | |
| J1107 | 200.0 | ±87.7 | 2 x 14 MVAr Cap | 197.4 | 82.2 | 0.9232 | 196.2 | -142.2 | -0.8097 | Yes | |
| J1111 | 150.0 | ±25.144 | N/A | 148.0 | -2.4 | 0.9999 | 147.7 | -57.6 | -0.9317 | No | 51.0 |
| J1112 | 153.3 | ±74.2 | N/A | 151.5 | 57.4 | 0.9351 | 150.8 | -101.3 | -0.8301 | Yes | |
| J1115 | 200.0 | ±65.793 | 4 x 15 MVAr Cap | 195.8 | 112.5 | 0.8671 | 194.3 | -106.3 | -0.8773 | Yes | |
| J1139 | 151.2 | ±95.3400 | N/A | 149.4 | 74.0 | 0.8961 | 148.6 | -127.8 | -0.7582 | Yes | |
| J1145 | 250.0 | ±119.07 | N/A | 246.5 | 68.0 | 0.9640 | 244.4 | -200.6 | -0.7730 | No | 13.0 |
| J1152 | 200.0 | ±94.3 | N/A | 196.6 | 52.1 | 0.9666 | 194.4 | -163.8 | -0.7647 | No | 12.5 |
| J1180 | 75.0 | ±65.233 | 4 x 6 MVAr Cap<br>1 x 6 MVAr Inductor | 73.8 | 86.8 | 0.6478 | 73.2 | -86.9 | -0.6442 | Yes | |
| J1182 | 250.0 | ±82.1710 | N/A | 248.3 | 60.8 | 0.9713 | 248.1 | -107.2 | -0.9180 | No | 20.8 |
| J1189 | 4.95 | 0.0 | N/A | 4.9 | 0.3 | 0.9948 | 4.9 | 0.5 | -0.9948 | No | 1.3 |
| J956 | 200.6 | ±97 | N/A | 197.9 | 68.1 | 0.9456 | 196.9 | -141.3 | -0.8124 | Yes | |
| J968 | 200.0 | 66<br>-64 | 2 x 12 MVAr Cap | 196.7 | 62.6 | 0.9529 | 195.6 | -105.1 | -0.8809 | No | 2.1 |
| J974 | 250.0 | 82.5<br>-80 | 2 x 9 MVAr Cap | 244.0 | 61.7 | 0.9695 | 241.9 | -137.2 | -0.8698 | No | 18.5 |
| J976 | 300.0 | ±146.4 | 2 x 4 MVAr Cap | 293.7 | 98.3 | 0.9483 | 289.9 | -238.9 | -0.7717 | Yes | |
| J979 | 170.0 | ±56.1 | 2 x 19 MVAr Cap | 167.4 | 75 | 0.9126 | 166.6 | -91.7 | -0.8761 | Yes | |
| J987 | 100.0 | ±44.24 | 2 x 7 MVAr Cap | 98.8 | 42.2 | 0.9196 | 98.2 | -70.1 | -0.8139 | Yes | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| J991 | 150.0 | ±66.36 | 2 x 14 MVAr Cap | 148.5 | 78.4 | 0.8843 | 148.1 | -92.7 | -0.8476 | Yes | |
| J992 | 200.0 | ±88.48 | 2 x 14 MVAr Cap | 197.5 | 82.7 | 0.9224 | 196.2 | -146.3 | -0.8017 | Yes | |
| J993 | 200.0 | ±88.48 | 2 x 14 MVAr Cap | 197.3 | 81.1 | 0.9249 | 196.0 | -145.3 | -0.8033 | Yes | |
| J994 | 100.0 | ±44.24 | 2 x 7 MVAr Cap | 98.8 | 40.8 | 0.9243 | 98.0 | -73.5 | -0.8000 | Yes | |

# 3. Model Development and Study Assumptions

## 3.1. Base Case Models

The origin of the DPP 2018 April Central models is the MTEP 18 models with the Bench Cases including all pre-queued projects and associated network upgrades, while the Study Cases contain all of the interconnection requests in DPP 2018 April Central Phase II, in addition to all the facilities in the Bench Cases.

- Bench Cases
    - APR18-2023SH-Bench_Discharging_Phase_2 Final 041720.raw
    - APR18-2023SUM-Bench_Discharging_Phase_2 Final 041720.raw
- Study Cases
    - APR18-2023SH-Study_Charging_Phase_2 Final 041720.raw
    - APR18-2023SUM-Study_Charging_Phase_2 Final 041720.raw
    - APR18-2023SH-Study_Discharging_Phase_2 Final 041720.raw
    - APR18-2023SUM-Study_Discharging_Phase_2 Final 041720.raw

## 3.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

## 3.3. Contingencies

The following contingencies were considered in the steady state analysis:

1) NERC Category P0 (system intact -- no contingencies)
2) NERC Category P1 contingencies
    a. Single element outages, at buses with a nominal voltage of 68 kV and above
    b. Multiple element NERC Category P1 contingencies
3) NERC Category P2-P7 contingencies
4) For all the contingencies 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.

## 3.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2018 April Central generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.7.0 and TARA version 1902.

### 3.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the applicable rating (normal or emergency) of the overloaded facility, or
4) For any other constrained facility, where none of the Study Generators meet one of the above criteria, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) will be responsible for mitigating the cumulative MW impact constraint, or
5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or
6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

1) The bus voltage is outside of the 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 generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of Interconnection Service. Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the Deliverability algorithm, to meet the system performance criteria for NERC category P1 events, if DFAX due to the study generator is equal to or greater than 5%.

## 4. Thermal Analysis

The thermal analysis results for 2018 April show generator projects J1025, J1026, J1063, J1111, and J1182 causing constraints. The details pertaining to the thermal analysis can be found in Appendix A – Ameren System Impact Study Report (CEII) and Appendix C – MISO ERIS Analysis (CEII).

## 5. Voltage Analysis

The voltage analysis results for 2018 April show that the study generators do not cause any voltage violations. The details pertaining to the voltage analysis can be found in Appendix C – MISO ERIS Analysis (CEII).

## 6. Stability Analysis

The MISO DPP Stability analysis shows that the study projects did not adversely impact the system.

An additional stability study capturing the Ameren Local Planning Criteria (LPC) for new generation interconnections was also performed by Ameren and also shows that study projects did not adversely impact the system under the Ameren LPC for new generation interconnections. The details pertaining to the stability analysis can be found in Appendix F – MISO Stability Analysis (CEII) and Appendix G – Ameren Stability Analysis (CEII).

## 6.1. Model Development

The following summer/shoulder discharging 2023 models were developed based on Phase II study models. The Ameren LPC stability models were also developed based on the Phase II stability study models and were adjusted in order to comply with Ameren's LPC by fully dispatching nearby local generation.

• Bench Cases:
    APR18-2023SH-Bench_Discharging_Phase_2 Final 041720.raw
    APR18-2023SUM-Bench_Discharging_Phase_2 Final 041720.raw
• Study Cases:
    APR18-2023SH-Study_Discharging_Phase_2 Final 041720.raw
    APR18-2023SUM-Study_Discharging_Phase_2 Final 041720.raw

## 6.2. Study Methodology

The purpose of the study is to identify potential angular instabilities, voltage dip violations, and damping violations, if any, due to the interconnection of the projects in the DPP 2018 April Central study cycle under disturbance conditions, and the impact of all study projects on the system stability performance.

The MISO fault scenarios simulated in this study cover faults simulated as part of the MTEP18 analysis as well as selected three-phase (3PH) faults with normal clearing and single line to ground (SLG) faults with delayed clearing. Dynamic simulations of fault scenarios were performed using the DSATools TSAT program (version 18.0.10).

The Ameren fault scenarios that were simulated in their LPC study were created by Ameren and are localized around each study projects POI. The fault said Ameren used were not based off of the MTEP18 stability package. Ameren also used PSS/E to run the stability analysis.

Fault scenarios were first simulated using the study case and the results were reviewed. For scenarios that exhibited instability, the bench case was simulated such that the stability performance with and without the proposed interconnection projects could be compared. Any new stability problems attributed to the proposed interconnection projects are flagged and reported.

For each fault, rotor angles, speed deviation, and electrical power outputs of the study generators and the generators in the proximity were monitored. Voltages at selected buses, including all POI buses of the study projects and all future buses, were also monitored.

Additional Ameren LPC criteria is listed in section 6.3 below.

A summary of the generation dispatch for the Entergy LPC analysis has been tabulated in Appendix E – Entergy Local Planning Criteria Stability Analysis (CEII).
The fault scenarios simulated in the Entergy LPC study cover selected 3PH and 3PH P3 contingency faults with normal clearing. In each fault scenario, a generator is disconnected at 0.5 seconds and the simulation continues to run until 5.0 seconds at which point the fault is initiated and the total simulation run time is 20.0 seconds.

## 6.3. Study Criteria

The transient stability study criteria that was used as part of this study is based upon 2 sets of guidelines:

<u>Ameren's Transmission Planning Criteria and Guidelines</u>

Ameren Transmission Planning Criteria and Guidelines prescribe the fault scenarios that should be evaluated in a transient stability and a small signal stability analysis. These criteria state that plant transmission outlet is considered adequate, from the standpoint of stability, if the following conditions are met:

1. With all lines in service, the plant and remainder of the system shall remain stable when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.

2. With all lines in service, the plant and the remainder of the system shall remain stable when a sustained single-line-to-ground fault on any two circuits of a multiple circuit tower line is cleared in primary clearing time.

3. With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained three-phase fault on any of the remaining outlet facilities is cleared in primary clearing time.

4. With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained double-line-to-ground (2-L-G) fault on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker".

Ameren's transient voltage recovery criteria states that "following clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 85% of nominal or greater within fifteen seconds".

<u>MISO's Transmission Planning Criteria and Guidelines:</u>

All renewable study projects are subject to the voltage ride-through and frequency ride-through criteria specified in NERC PRC-024-2 ("Generator Frequency and Voltage Protective Relay Settings") to check if the projects remain connected during frequency and voltage excursions. Specifically, PRC-024-2 mandates that protective relaying should be set in such a way that:

- Voltage Ride-Through: a generator shall withstand zero voltage at the POI (typically the primary side of the station transformer) for up to 0.15 seconds (9 cycles) and the ensuing voltage recovery period for three phase faults.
- Frequency Ride-Through: a generator shall maintain continuous operation between 59.5 and 60.5 Hz.

### 6.4. Study Results

<u>Ameren Stability Results:</u>

Based on the simulations performed in this study, the performance of the MISO projects J955, J976, J979, J987, J991, J994, J1022, J1026, J1055, J1107 and J1115 were found be acceptable under the fault scenarios prescribed by the Ameren Planning Criteria and Guidelines.

Projects J1087, J1094 and J1096 may also be deemed to have acceptable performance if the frequency relay protection settings can be adjusted to allow the generators to ride through the Ameren prescribed fault scenarios. J991 will be subject to the local Xenia operating guide and will not be allowed to operate when it is active.

Ameren was not able to evaluate the voltage and frequency ride-through capability of MISO projects J956, J1033, J1039 and J1139 because the generator customer did not provide data to model voltage and frequency relays.

MISO projects J974, J1102, J1145 and J1180 will be required to implement STATCOMs or similar devices since they were not able to ride-through the fault scenarios evaluated or were not able to maintain acceptable voltage profiles after the fault was cleared.

MISO project J1025 performance was found to be acceptable with the withdrawal of projects J966 and J1177 and an election change to project J1182.

There were no violations of Ameren's transient voltage recovery criteria at transmission buses. A few violations occurred at distribution buses which do not require mitigation. No issues with nearby synchronous generators were observed. The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix G – Ameren Stability Analysis (CEII).

MISO Stability Results:

No network upgrades were identified or assigned to any study projects. Only some model tuning is needed for specific projects prior to moving onto Phase 3.

J1055 summer plots observed oscillation issues associated with the Torque control model. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1069's Generic Renewable Drive Train Model need tuning as would not run. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

Some of J1022 summer plots observed oscillation issues. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1055, J968, J974, and J1087 tripped offline for various fault simulations. Relay protection models may need to be tuned to prevent this occurrence. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix F – MISO Stability Analysis (CEII).

# 7. Short Circuit Analysis

The short circuit analysis results for 2018 April show that the study generators do not cause any short circuit violations. The details pertaining to the short circuit analysis can be found in Appendix H – Short Circuit Study Analysis (CEII).

# 8. Affected System Impact Study

The details pertaining to the AECI, PJM, SPP, and TVA Affected Systems studies are in Appendix I – AECI Affected Systems Study Report (CEII), Appendix J – PJM Affected Systems Study Report (CEII), Appendix K – SPP Affected Systems Study Report (CEII), Appendix L – TVA Affected Systems Study Report (CEII).

## 8.1. J955

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 21.20% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of $2.5 million. The project is allocated 89.84% of the cost.

3. AD1-133 - Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to perform sag mitigation, upgrade station conductor, upgrade 2 breakers, 2 disconnect switches, and CTs with a cost estimate of $20.5 million. The project is allocated 100% of the cost.

4. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of $5 million. The project is allocated 50.24% of the cost.

### 8.2. J956

No affected systems mitigations were found to be required for this generator.

### 8.3. J968

No affected systems mitigations were found to be required for this generator.

### 8.4. J974

The PJM Study identified that this generator contributes to the following constraints:

1. Goodings 3B – Goodings 4B 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 345 kV circuit breaker and station conductor with a cost estimate of $3.2 million. The project is allocated 100% of the cost.

2. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $6.925 million. The project is allocated 5.98% of the cost.

3. Crete – St. John 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $11.2 million. The project is allocated 1.19% of the cost. The second portion of the upgrade will replace a 345 kV breaker and associated equipment at Crete with a cost of $6 million. The project is allocated 2.22% of the cost.

4. Wilton R – Wilton 3M 765 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to build-out and relocate the Wilton 765 kV bus and install 2 new breakers with a cost estimate of $12 million. The project is allocated 1.82% of the cost.

5. East Frankford – Crete 345 kV

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 161 kV jumpers for the transformer with a cost estimate of $10.3 million. The project is allocated 6.58% of the cost.

### 8.5. J976

No affected systems mitigations were found to be required for this generator.

### 8.6. J979

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 4.39% of the cost.

2. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of $18.5 million. The project is allocated 16.52% of the cost.

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### 8.7. J987

No affected systems mitigations were found to be required for this generator.

### 8.8. J991

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 5.96% of the cost.

### 8.9. J992

No affected systems mitigations were found to be required for this generator.

### 8.10. J993

No affected systems mitigations were found to be required for this generator.

### 8.11. J994

No affected systems mitigations were found to be required for this generator.

### 8.12. J1022

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 3.03% of the cost.

### 8.13. J1025

No affected systems mitigations were found to be required for this generator.

### 8.14. J1026

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 50.5% of the cost.

### 8.15. J1027

No affected systems mitigations were found to be required for this generator.

### 8.16. J1028

No affected systems mitigations were found to be required for this generator.

### 8.17. J1033

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 9.64% of the cost.

2. Essex – Stoddard 161 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Essex to Stoddard 161 kV line with a cost estimate of $861,000. The project is allocated 18.23% of the cost.

### 8.18. J1034

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 43.35% of the cost.

2. Essex – Stoddard 161 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Essex to Stoddard 161 kV line with a cost estimate of $861,000. The project is allocated 81.77% of the cost.

### 8.19. J1039

No affected systems mitigations were found to be required for this generator.

### 8.20. J1055

The PJM Study identified that this generator contributes to the following constraints:

1. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $6.925 million. The project is allocated 2.16% of the cost.

### 8.21. J1058

The PJM Study identified that this generator contributes to the following constraints:

1. St John – St John Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of $20.8 million. The project is allocated 17.55% of the cost.

2. St John Tap – Greenacre 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the ComEd portion of the line with a cost estimate of $7.9 million. The project is allocated 17.55% of the cost.

3. Greenacre Tap – Olive 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of $13.9 million. The project is allocated 8.96% of the cost.

### 8.22. J1063

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of $12.095 million. The project is allocated 47% of the cost.

### 8.23. J1067

No affected systems mitigations were found to be required for this generator.

### 8.24. J1069

No affected systems mitigations were found to be required for this generator.

### 8.25. J1074

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of $12.095 million. The project is allocated 21% of the cost.

### 8.26. J1087

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 22.66% of the cost.

### 8.27. J1094

No affected systems mitigations were found to be required for this generator.

### 8.28. J1096

No affected systems mitigations were found to be required for this generator.

### 8.29. J1102

No affected systems mitigations were found to be required for this generator.

### 8.30. J1107

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 15.44% of the cost.

### 8.31. J1111

No affected systems mitigations were found to be required for this generator.

### 8.32. J1112

No affected systems mitigations were found to be required for this generator.

### 8.33. J1115

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 3.57% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of $16.7 million. The project is allocated 27% of the cost.

3. AB2-047 Tap – Z2-087 Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of $18.5 million. The project is allocated 27% of the cost.

### 8.34. J1139

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 4.31% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of $2.5 million. The project is allocated 10.16% of the cost.

3. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of $16.7 million. The project is allocated 73% of the cost.

4. AB2-047 Tap – Z2-087 Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of $18.5 million. The project is allocated 73% of the cost.

5. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace 2-345kV circuit breakers, 5-345kV disconnect switches, mitigate line sag, station conductor with relay package with a cost estimate of $18.5 million. The project is allocated 83.48% of the cost.

6. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of $5 million. The project is allocated 5.03% of the cost.

### 8.35. J1145

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 23.3% of the cost.

### 8.36. J1152

The PJM Study identified that this generator contributes to the following constraints:

1. Cayuga – Eugene 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a new 345 kV circuit in parallel with a cost estimate of $12.095 million. The project is allocated 32% of the cost.

### 8.37. J1180

No affected systems mitigations were found to be required for this generator.

### 8.38. J1182

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 26.2% of the cost.

### 8.39. J1189

No affected systems mitigations were found to be required for this generator.

## 9. Deliverability Analysis

### 9.1. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an Energy Resource (ER) project or to proceed with the system upgrades that will make the generator fully deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100% of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C.

### 9.2. Determining the MW Restriction

If one facility is overloaded based on the assessed "severe yet credible dispatch" scenario described in the study methodology, and the generator under study has a DF greater than 5%, part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

If the result is larger than the maximum output of the generator, 100% of this generator's output is not deliverable.

### 9.3. Deliverability Study Results

The limiting constraints (mon-con pairs) seen in the deliverability analysis for the 2018 Summer case are summarized in Appendix D - Deliverability Analysis (CEII).

#### 9.3.1. J955

This generator is found to be fully deliverable for 1165 MW without any network upgrades.

#### 9.3.2. J956

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 6 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 6: NRIS Results for J956**

| J956 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 188.10 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 200 | 42.10% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 8,734,642 | 45,000,000 |

#### 9.3.3. J968

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.4. J974

This generator is found to be fully deliverable for 250 MW without any network upgrades.

#### 9.3.5. J976

This generator is determined to be fully deliverable for 282.16 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 7 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 7: NRIS Results for J976**

| J976 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 282.16 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 300 | 16.92% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 5,265,682 | 45,000,000 |

#### 9.3.6. J979

This generator is found to be fully deliverable for 170 MW without any network upgrades.

#### 9.3.7. J987

This generator is determined to be fully deliverable for 94.05 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 9 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 8: NRIS Results for J987**

| J987 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 94.05 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 100 | 17.37% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, | 1,801,909 | 45,000,000 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | J1094, J1107, J1111, J1145 | | |

### 9.3.8. J991

This generator is found to be fully deliverable for 150 MW without any network upgrades.

### 9.3.9. J992

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.10. J993

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.11. J994

This generator is determined to be fully deliverable for 94.05 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 10 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 9: NRIS Results for J994**

| J994 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 94.05 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 100 | 13.75% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 1,426,381 | 45,000,000 |

### 9.3.12. J1022

This generator is found to be fully deliverable for 150 MW without any network upgrades.

### 9.3.13. J1025

This generator is found to be fully deliverable for 300 MW without any network upgrades.

### 9.3.14. J1026

This generator is determined to be fully deliverable for 329.18 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 12 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 10: NRIS Results for J1026**

| J1026 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 329.18 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 350 | 45.29% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 16,443,844 | 45,000,000 |

### 9.3.15. J1027

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 13 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 11: NRIS Results for J1027**

| J1027 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J829 – Dresser 345kV Line | 150 | 5.99% | No | - | J1027, J1028, J1074, J1189 | 10,155,153 | 45,500,000 |

### 9.3.16. J1028

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 14 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 12: NRIS Results for J1028**

| J1028 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 0 | 5.02% | No | - | J1028, J1074, J1152 | 1,636,364 | 6,000,000 |
| J829 – Dresser 345kV Line | 150 | 6.22% | No | - | J1016, J1074, J1028, J1027, J1189 | 9,198,791 | 45,500,000 |

#### 9.3.17. J1033

This generator is determined to be fully deliverable for 47.03 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 15 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 13: NRIS Results for J1033**

| J1033 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 47.03 MW (94.06%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 50 | 6.46% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 335,070 | 45,000,000 |

#### 9.3.18. J1034

This generator is determined to be fully deliverable for 211.62 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 16 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 14: NRIS Results for J1034**

| J1034 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 211.62 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 225 | 6.46% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, | 1,507,815 | 45,000,000 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | J1087, J1094, J1107, J1111, J1145 | | |

### 9.3.19. J1039

This generator is determined to be fully deliverable for 47.03 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 17 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 15: NRIS Results for J1039**

| J1039 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 47.03 MW (94.06%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 50 | 16.92% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 877,614 | 45,000,000 |

### 9.3.20. J1055

This generator is found to be fully deliverable for 144 MW without any network upgrades.

### 9.3.21. J1058

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.22. J1063

This generator is determined to be fully deliverable for 134.42 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 17 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 16: NRIS Results for J1063**

| J1063 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 134.42 MW (68.93%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) | Level of Service | Distribution Factor | Constraint in ERIS | Projects Associated | Projects Associate | Upgrade Cost | Total Cost of |
|---|---|---|---|---|---|---|---|

| (i.e. All upgrades must be made for 100% NRIS) | Attainable (MW) | | Analysis? | with ERIS Constraint | d with NRIS Constraint | Allocated to Project | Upgrade ($) |
|---|---|---|---|---|---|---|---|
| Clarkshill – Thorntown 69 kV | 195 | 9.97% | No | - | J1063 | 18,954,200 | 18,954,200 |

### 9.3.23. J1067

This generator is found to be fully deliverable for 240 MW without any network upgrades.

### 9.3.24. J1069

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.25. J1074

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 19 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 17: NRIS Results for J1074**

| J1074 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 0 | 5.02% | No | - | J1028, J1074, J1152 | 2,181,818 | 6,000,000 |
| J829 – Dresser 345kV Line | 200 | 10.89% | No | - | J1027, J1028, J1074, J1189 | 24,616,497 | 45,500,000 |

### 9.3.26. J1087

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 20 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 18: NRIS Results for J1087**

| J1087 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 188.10 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 200 | 6.36% | No | - | J956, J976, J987, J994, J1026, J1033, | 1,319,532 | 45,000,000 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | J1034, J1039, J1087, J1094, J1107, J1111, J1145 | | |

#### 9.3.27. J1094

This generator is determined to be fully deliverable for 141.08 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 21 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 19: NRIS Results for J1094**

| J1094 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 141.08 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 150 | 7.89% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 1,227,725 | 45,000,000 |

#### 9.3.28. J1096

This generator is found to be fully deliverable for 150 MW without any network upgrades.

#### 9.3.29. J1102

This generator is found to be fully deliverable for 70 MW without any network upgrades.

#### 9.3.30. J1107

This generator is determined to be fully deliverable for 188.10 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 22 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 20: NRIS Results for J1107**

| J1107 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 188.10 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) | Level of Service | Distribution Factor | Constraint in ERIS | Projects Associated | Projects Associated | Upgrade Cost | Total Cost of |
|---|---|---|---|---|---|---|---|

| (i.e. All upgrades must be made for 100% NRIS) | Attainable (MW) | | Analysis? | with ERIS Constraint | with NRIS Constraint | Allocated to Project | Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 200 | 6.55% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 1,358,952 | 45,000,000 |

### 9.3.31. J1111

This generator is determined to be fully deliverable for 141.08 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 23 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 21: NRIS Results for J1111**

| J1111 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 141.08 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 150 | 6.61% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 1,028,551 | 45,000,000 |

### 9.3.32. J1112

This generator is found to be fully deliverable for 150 MW without any network upgrades.

### 9.3.33. J1115

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.34. J1139

This generator is found to be fully deliverable for 150 MW without any network upgrades.

### 9.3.35. J1145

This generator is determined to be fully deliverable for 235.13 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 25 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 22: NRIS Results for J1145**

| J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 235.13 MW (94.05%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J1026 – Maywood 345kV Rebuild | 250 | 14.16% | No | - | J956, J976, J987, J994, J1026, J1033, J1034, J1039, J1087, J1094, J1107, J1111, J1145 | 3,672,284 | 45,000,000 |

#### 9.3.36. J1152

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 19 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 23: NRIS Results for J1152**

| J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 200 | 5.02% | No | - | J1028, J1074, J1152 | 2,181,818 | 6,000,000 |

#### 9.3.37. J1180

This generator is found to be fully deliverable for 75 MW without any network upgrades.

#### 9.3.38. J1182

This generator is found to be fully deliverable for 250 MW without any network upgrades.

#### 9.3.39. J1189

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 27 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 24: NRIS Results for J1189**

| J1189 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J829 – Dresser 345kV Line | 4.95 | 5.70% | No | - | J1027, J1028, J1074, J1189 | 318,896 | 45,500,000 |

## 10. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) Analysis tests for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study.

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations appear in Table 28.

**Table 25: Maximum MW Impact and SNU Cost Allocations**

| Network Upgrades | Project Study Cycle | Projects sharing cost | MW Contribution | Total NU Cost ($) | Cost Responsibility ($) |
|---|---|---|---|---|---|
| N/A | N/A | N/A | N/A | N/A | N/A |

## 11. Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

### 11.1. Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade identified in System Impact Study was provided by the corresponding transmission owning company.

### 11.2. Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case.

Cost Allocation Methodology for Thermal Constraints

1. With all Study Group generation projects dispatched in the Post Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine

the cost allocation of one NU is:

$$\mathit{Project\ A\ cost\ portion\ of\ NU\ Cost\ of\ NU} = \frac{Max(Proj.A\ MW\ contribution\ on\ constraint)}{\sum_i Max(Proj.i\ MW\ contrution\ on\ constraint)}$$

6. The total NU costs for each project are calculated if more than one NU is required.

**Appendix A – Ameren System Impact Study Report (CEII)**

**Appendix B – Cost Allocation Summary (CEII)**

**Appendix C – MISO ERIS Analysis (CEII)**

**Appendix D – MISO Deliverability Analysis (CEII)**

**Appendix E – Network Upgrades Per Project (CEII)**

**Appendix F – MISO Stability Analysis (CEII)**

**Appendix G – Ameren Stability Analysis (CEII)**

**Appendix H – Short Circuit Study Analysis (CEII)**

**Appendix I – AECI Affected Systems Study Report (CEII)**

**Appendix J – PJM Affected Systems Study Report (CEII)**

**Appendix K – SPP Affected Systems Study Report (CEII)**

**Appendix L – TVA Affected Systems Study Report (CEII)**

**Appendix M – MISO A10 Results (CEII)**

# MISO DPP 2018 April Central Area Study Phase III Report

10/12/2021

Revision 2

**MISO**
**720 City Center**
**Drive Carmel**
**Indiana 46032**
http://www.misoenergy.org

## Contents

## 1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2018 April Central Area Phase III (Central Area DPP III). The study was performed under the direction of MISO and reviewed by an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren (AMIL, AMMO, ATXI), Duke Energy (DEI), Hoosier Energy (HE), Indianapolis Power & Light Company (IPL), Northern Indiana Public Service Company (NIPSCO), Southern Illinois Power Cooperative (SIPC), and Southern Indiana Gas & Electric Company (SIGE).

### 1.1. Project List

The original interconnection requests for DPP 2018 April Central Area had a total of 61 generation projects.

- Projects J957, J973, J983, J1012, J1017, J1018, J1019, J1035, J1066, J1080, J1116, J1118, and J1150 withdrew prior to the Phase I study.
- 48 generation projects with a combined nameplate rating of 9348.23 MW (ERIS) & 9348.23 MW (NRIS) were studied in Phase I.
- Projects J980, J985, J995, J1016, J1021, J1031, J1059, J1123, J1148, J1161 withdrew during Decision Point 1 (Prior to Phase II Kickoff).
- 39 generation projects with a combined nameplate rating of 7888.95 MW (ERIS) & 7838.95 MW (NRIS) were studied in Phase II.
- Projects J1033, J1039, J1111, J1112 withdrew during Decision Point 2 (Prior to Phase III Kickoff).
- 35 generation projects with a combined nameplate rating of 7,300 MW (ERIS) & 7,150 MW (NRIS) were studied in Phase III.

The Central Area DPP Phase III study was kicked off on March 16th, 2021 and consisted of the projects shown below in Table 1.

**Table 1: List of DPP April 2018 Central Area Phase III Projects**

| Project | Fuel Type | Transmission Owner | County | State | Service Requested | MW | POI |
|---|---|---|---|---|---|---|---|
| J955 | Gas | Ameren Transmission Company of Illinois | Sangamon County | IL | NRIS | 1165 | Austin Substation 345kV Bus |
| J956 | Solar | Ameren Missouri | Ralls County | MO | NRIS | 200 | Spencer Creek 345kV Substation |
| J968 | Wind | Northern Indiana Public Service Company | Jasper County,White County | IN | NRIS | 200 | Reynolds 345kV Substation |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J974 | Wind | Ameren Illinois | Fulton County,Peoria County | IL | NRIS | 225 | Mapleridge 345kV Switching Station |
| J976 | Solar | Ameren Missouri | Warren County | MO | NRIS | 300 | Montgomery - Enon 345kV Line Tap |
| J979 | Wind | Ameren Transmission Company of Illinois | Christian County | IL | NRIS | 170 | Pana Substation 345kV Bus |
| J987 | Solar | Ameren Missouri | Montgomery County | MO | NRIS | 100 | Montgomery 161kV Substation |
| J991 | Solar | Ameren Illinois | Clay County | IL | NRIS | 150 | Xenia 345kV Switching Station |
| J992 | Solar | Duke Energy Indiana | Cass County | IN | NRIS | 200 | Walton 230kV Substation |
| J993 | Solar | Indianapolis Power & Light Company | Boone County | IN | NRIS | 200 | Hortonville - Whitestown 345kV Line Tap |
| J994 | Solar | Ameren Missouri | Callaway County | MO | NRIS | 100 | Guthrie 161 kV Substation |
| J1022 | Wind | Ameren Illinois | McLean County | IL | ERIS | 150 | Weedman Substation 138kV Bus |
| J1025 | Wind | Ameren Transmission Company of Illinois | Knox County | MO | NRIS | 290 | Zachary - Maywood 345 kV Line Tap |
| J1026 | Wind | Ameren Missouri | Audrain County,Ralls County | MO | ERIS/NRIS | 380/265 | Maywood - Spencer Creek 345 kV Line Tap |
| J1027 | Solar | Hoosier Energy | Pike County | IN | NRIS | 150 | Ratts 161 kV Substation |
| J1028 | Solar | Hoosier Energy | Pike County | IN | NRIS | 150 | Ratts - Victory 161 kV Line Tap |
| J1034 | Solar | Ameren Missouri | Stoddard County | MO | NRIS | 225 | Stoddard - Morley 161kV Line Tap |
| J1055 | Wind | Ameren Illinois | Mason County | IL | NRIS | 144 | Mason Substation 138 kV Bus |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J1058 | Solar | Northern Indiana Public Service Company | Lake County | IN | NRIS | 200 | Schahfer-St. John 345kV Line Tap |
| J1063 | Solar | Duke Energy | Clinton County | IN | NRIS | 195 | New London - Frankfort 230kV Line Tap |
| J1067 | Solar | Northern Indiana Public Service Company | Jasper County,Pulaski County | IN | NRIS | 240 | Reynolds - Burr Oak 345kV Line |
| J1069 | Wind | Northern Indiana Public Service Company | Jasper County,Pulaski County | IN | NRIS | 200 | Reynolds 345kV Substation |
| J1074 | Solar | Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. | Gibson County | IN | NRIS | 200 | Francisco 138 kV sub |
| J1087 | Solar | Ameren Missouri | Scott County | MO | NRIS | 200 | Miner - Kelso 161 kV Line Tap |
| J1094 | Solar | Ameren Illinois | Washington County | IL | NRIS | 150 | Prest 138kV Switching Station |
| J1096 | Solar | Ameren Illinois | Saline County | IL | NRIS | 150 | Norris City North - Muddy 138 kV Line |
| J1102 | Solar | Ameren Illinois | Logan County | IL | NRIS | 70 | Fogarty 138 kV Substation |
| J1107 | Solar | Ameren Missouri | Cape Girardeau County | MO | NRIS | 200 | Kelso - Lutesville 345 kV Line Tap |
| J1115 | Wind | Ameren Illinois | Macon County | IL | NRIS | 200 | Latham - Oreana 345kV Line |
| J1139 | Solar | Ameren Illinois | Champaign County | IL | NRIS | 135 | Sidney Substation 138 kV Bus |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| J1145 | Solar | Ameren Missouri | Callaway County | MO | NRIS | 250 | Overton - (McCrede) - Montgomery 345 kV Line Tap |
| J1152 | Solar | Duke Energy | Shelby County | IN | NRIS | 200 | Gwynneville 345kV Substation |
| J1180 | Solar | Ameren Illinois | Clark County | IL | NRIS | 75 | Casey West - Sullivan 345 kV Line |
| J1182 | Solar | Ameren Transmission Company of Illinois | Adair County | MO | NRIS | 250 | Zachary Substation 345 kV Bus |
| J1189 | Battery Storage | Duke Energy Indiana | Brown County,Martin County | IN | NRIS | 4.95 | Crane Solar 69kV Substation |

## 1.2. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2018 April Central Phase III reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

**Table 2: Total Cost of Network Upgrades for DPP 2018 April Central Phase III Projects**

| Project | ERIS Network Upgrades ($) | | | | NRIS Network Upgrades ($) | Interconnection Facilities ($) | | Shared Network Upgrades ($) | Total Network Upgrade Cost ($) | M2 ($) | M3 ($) | M4 ($) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Thermal | Stability | Short Circuit | Affected System | Deliverability | TO Network Upgrades | TO – Owned Direct Assigned | | | | | |
| a | b | c | d | e | f | g | h | i | j = b+c+d+f+g+i | $4,000/MW | 10% of (j) from Phase I-M2 | (20% of (j) from Phase II)-M2-M3 |
| J955 | 2,730,900 | 0 | 0 | 24,072,200 | 0 | 884,000 | 1,346,000 | 0 | 3,614,900 | 4,660,000 | 0 | 0.00 |
| J956 | 0 | 0 | 0 | 0 | 0 | 1,170,000 | 1,626,000 | 0 | 1,170,000 | 800,000 | 9,725.10 | 1,171,203.10 |
| J968 | 0 | 0 | 0 | 0 | 0 | 1,102,243 | 810,385 | 0 | 1,102,243 | 800,000 | 0 | 0.00 |
| J974 | 0 | 0 | 0 | 4,777,168 | 0 | 1,596,000 | 1,092,000 | 0 | 1,596,000 | 1,000,000 | 0 | 0.00 |
| J976 | 0 | 0 | 0 | 0 | 0 | 4,906,500 | 494,000 | 0 | 4,906,500 | 1,200,000 | 0 | 834,436.40 |
| J979 | 15,000 | 0 | 0 | 1,953,800 | 0 | 4,042,000 | 1,519,000 | 0 | 4,057,000 | 800,000 | 0 | 8,400.00 |
| J987 | 0 | 0 | 0 | 0 | 0 | 831,000 | 1,229,000 | 0 | 831,000 | 400,000 | 0 | 126,581.80 |
| J991 | 0 | 0 | 0 | 298,000 | 0 | 2,391,000 | 1,199,000 | 0 | 2,391,000 | 800,000 | 0 | 0.00 |
| J992 | 0 | 0 | 0 | 0 | 0 | 4,509,448 | 1,474,438 | 0 | 4,509,448 | 800,000 | 0 | 101,889.60 |
| J993 | 0 | 0 | 0 | 0 | 0 | 16,350,303 | 569,301 | 0 | 16,350,303 | 800,000 | 242,500.00 | 2,227,560.60 |
| J994 | 0 | 0 | 0 | 0 | 0 | 896,000 | 762,000 | 0 | 896,000 | 400,000 | 0 | 64,476.20 |
| J1022 | 0 | 0 | 0 | 151,000 | 0 | 1,970,000 | 876,000 | 0 | 1,970,000 | 600,000 | 0 | 0.00 |
| J1025 | 9,084,000 | 0 | 0 | 0 | 0 | 9,957,000 | 1,024,000 | 0 | 19,041,000 | 1,200,000 | 2,948,233.00 | 1,343,319.80 |
| J1026 | 0 | 0 | 0 | 4,037,000 | 0 | 1,170,000 | 1,626,000 | 0 | 1,170,000 | 1,600,000 | 1,203,627.90 | 3,286,991.70 |
| J1027 | 0 | 0 | 0 | 0 | 11,442,836 | 717,200 | 2,919,300 | 0 | 12,160,036 | 600,000 | 507,695.50 | 1,066,775.10 |
| J1028 | 0 | 0 | 0 | 0 | 11,694,804 | 9,916,400 | 1,819,200 | 0 | 21,611,204 | 600,000 | 1,109,879.10 | 2,682,564.70 |
| J1034 | 0 | 0 | 0 | 1,403,981 | 0 | 3,054,500 | 310,500 | 0 | 3,054,500 | 900,000 | 0 | 12,463.00 |
| J1055 | 0 | 0 | 0 | 149,800 | 0 | 1,156,000 | 881,000 | 0 | 1,156,000 | 576,000 | 0 | 0.00 |
| J1058 | 0 | 0 | 0 | 6,280,000 | 0 | 24,582,234 | 1,246,580 | 0 | 24,582,234 | 1,200,000 | 300,000.00 | 3,416,446.80 |
| J1063 | 11,260,800 | 0 | 0 | 0 | 18,954,200 | 12,954,151 | 1,164,322 | 0 | 43,169,151 | 1,200,000 | 4,996,500.00 | 2,437,330.20 |
| J1067 | 0 | 0 | 0 | 0 | 0 | 22,831,834 | 1,226,902 | 0 | 22,831,834 | 960,000 | 540,000.00 | 3,066,366.80 |
| J1069 | 0 | 0 | 0 | 0 | 0 | 1,102,243 | 810,385 | 0 | 1,102,243 | 800,000 | 0 | 0.00 |
| J1074 | 0 | 0 | 0 | 0 | 26,333,709 | 1,216,300 | 588,804 | 0 | 27,550,009 | 800,000 | 1,805,435.30 | 2,997,487.70 |
| J1087 | 0 | 0 | 0 | 725,369 | 0 | 8,322,000 | 621,000 | 0 | 8,322,000 | 800,000 | 935,301.00 | 193,005.40 |
| J1094 | 0 | 0 | 0 | 0 | 0 | 7,653,000 | 867,000 | 0 | 7,653,000 | 600,000 | 27,877.50 | 1,148,267.50 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| J1096 | 0 | 0 | 0 | 0 | 0 | 6,422,000 | 621,000 | 0 | 6,422,000 | 600,000 | 200,000.00 | 484,400.00 |
| J1102 | 0 | 0 | 0 | 0 | 0 | 1,031,000 | 517,000 | 0 | 1,031,000 | 280,000 | 0 | 0.00 |
| J1107 | 0 | 0 | 0 | 494,252 | 0 | 9,813,000 | 1,024,000 | 0 | 9,813,000 | 800,000 | 704,358.70 | 730,031.70 |
| J1115 | 0 | 0 | 0 | 2,635,700 | 0 | 9,847,000 | 1,024,000 | 0 | 9,847,000 | 800,000 | 280,000.00 | 889,400.00 |
| J1139 | 254,100 | 0 | 0 | 15,875,100 | 0 | 290,000 | 1,017,000 | 0 | 544,100 | 600,000 | 0 | 0.00 |
| J1145 | 0 | 0 | 0 | 1,865,000 | 0 | 9,855,000 | 1,024,000 | 0 | 9,855,000 | 1,000,000 | 388,122.80 | 1,317,334.00 |
| J1152 | 0 | 0 | 0 | 0 | 1,717,212 | 0 | 0 | 0 | 1,717,212 | 800,000 | 242,500.00 | 0.00 |
| J1180 | 0 | 0 | 0 | 0 | 0 | 15,006,000 | 1,024,000 | 0 | 15,006,000 | 300,000 | 880,000.00 | 1,821,200.00 |
| J1182 | 3,916,000 | 0 | 0 | 2,098,000 | 0 | 1,367,000 | 1,227,000 | 0 | 5,283,000 | | 390,083.40 | 615,313.00 |
| J1189 | 0 | 0 | 0 | 0 | 318,896 | 0 | 0 | 0 | 318,896 | 20,000 | 8,493.60 | 28,493.60 |

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in Table 3. Shared Network Upgrades are shown in Table 4.

**Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)**

| Network Upgrade | TO | GI projects requiring upgrade for ERIS | GI projects requiring upgrade for NRIS | Cost of solution ($) | TO Self-fund |
|---|---|---|---|---|---|
| 2nd Zachary 345kV Transformer and 2nd Zachary - Adair Line 161kV Line | AMMO | J1025, J1182 | | 13,000,000 | Yes |
| Coly - McKnight 500kV Terminal Upgrades | EES | | J1028, J1074, J1152, J1027 | 6,000,000 | No |
| Manson – Clarkshill 69kV Rebuild | DEI | J1063 | | 7,101,700 | No |
| Potato Creek – Manson 69kV Rebuild | DEI | J1063 | | 4,159,100 | No |
| Clarkshill – Thorntown 69kV Rebuild | DEI | | J1063 | 18,954,200 | No |
| Decatur – Main St. 138 kV Structures | AMIL | J955, J979 | | 500,000 | Yes |
| 2nd J829 - Dresser 345kV Circuit | DEI | | J1189, J1027, J1028, J1074 | 45,500,000 | No |
| Decatur – Main St. 138 kV Structures Rebuild | AMIL | J955, J979 | | 500,000 | Yes |
| Terminal Equipment replacement at Brokaw end of Brokaw - Z2-087 Tap line (MISO End) | AMIL | J955, J1139 | | 2,500,000 | Yes |

**Table 4: Shared Network Upgrades (Planning level cost estimates)**

| Shared Network Upgrade | TO | Higher queued projects associated with SNU | Study projects associated with SNU | Cost of solution ($) |
|---|---|---|---|---|
| No Projects Met Criteria – N/A | | | | |

**Note:**

1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.
3) Analysis performed shows there are two DPP-2018-APR Central projects for Shared Network Upgrade cost allocation.

## 2. FERC Order 827 Compliance Review

The Final Rule of FERC Order 827 “Reactive Power Requirements for Non-Synchronous Generation”, which was issued June 16, 2016, stated that “Under this Final Rule, newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of this Final Rule will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.” As such, this Final Rule applies to all non-synchronous (wind, solar, and battery storage) projects included in the DPP 2018 April Central study cycle.

In this study, the power factor at the high-side of the generator substation for each inverter based project was calculated and reviewed. The study method is to set Qgen of each study project at its Qmax, solve the case, then record the P and Q injection on the high side of the generator substation to calculate the lagging power factor (injecting VAR to the system). The same process is then repeated by setting Qgen at Qmin to calculate the leading power factor (absorbing VAR from the system).

The results show that all projects meets the requirement to maintain 0.95 leading power factor, however, four projects do not meet the requirement to provide reactive power capability corresponding to 0.95 lagging power factor, as highlighted in red below in **Table 5**. Additional reactive support will be needed for these projects to meet the FERC requirement on reactive power capability prior to the completion of their GIA.

**Table 5: FERC Order 827 Review Results**

| FERC Order 827 | | | | Steady State (At Generator Substation) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | VAR Injection | | | VAR Absorption | | | | |
| Project | Pmax (MW) | Reactive Power Capability (MVAr) | Proposed VAR Compensation | P (MW) | Q (MVar) | p.f. (pu) | P (MW) | Q (MVar) | p.f (pu) | Meet FERC Order 827 Requirement? | Add'l VAR Needed (MVAr) |
| J1022 | 155.3 | 72.53<br>-66.14 | 2 x 10 MVAr Cap | 152.0 | 71.3 | 0.9053 | 150.3 | -105.8 | -0.8177 | Yes | |
| J1025 | 319.0 | ±104.835 | 1 x 50 MVAr Cap | 306.0 | 134.9 | 0.9150 | 301.8 | -149.9 | -0.8956 | Yes | |
| J1026 | 413.6 | ±135.924 | 1 x 65 MVAr Cap | 390.2 | 143.9 | 0.9382 | 379.0 | -247.4 | -0.8374 | Yes | |
| J1027 | 150.0 | ±25.144 | N/A | 148.1 | -4.6 | 0.9995 | 147.7 | -61.3 | -0.9236 | No | 53.3 |
| J1028 | 150.0 | ±25.144 | N/A | 147.8 | -4.8 | 0.9995 | 147.4 | -62.2 | -0.9213 | No | 53.4 |
| J1034 | 225 | ±109 | 1 x 4 MVAr Cap | 221.1 | 74.7 | 0.9474 | 218.5 | -175.3 | -0.78 | Yes | |
| J1055 | 144.0 | 67.68<br>-80 | 1 x 7.5 MVAr Cap | 132.8 | 55.6 | 0.9224 | 125.6 | -128.5 | -0.6990 | Yes | |
| J1058 | 200.0 | ±97.6 | 1 x 4 MVAr Cap | 197.0 | 74.4 | 0.9355 | 195.6 | -134.9 | -0.8232 | Yes | |
| J1063 | 195 | ±95.2 | 2 x 4 MVAr Cap | 192.3 | 80.2 | 0.9229 | 191.2 | -129.4 | -0.8282 | Yes | |
| J1067 | 240.0 | ±97.9 | 2 x 17 MVAr Cap | 236.9 | 91.6 | 0.9327 | 235.4 | -161.4 | -0.8248 | Yes | |
| J1069 | 200.0 | ±81.6 | 2 x 14 MVAr Cap | 196.6 | 80.8 | 0.9249 | 195.1 | -130.3 | -0.8316 | Yes | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| J1074 | 200 | ±36.925 | 3 x 23 MVAr Cap | 197.4 | 78.4 | 0.9294 | 196.6 | -84.8 | -0.9182 | Yes | |
| J1087 | 200 | ±36.925 | N/A | 197.2 | 1.6 | 1 | 196.6 | -84.7 | -0.9184 | No | 63.2 |
| J1094 | 150 | ±25.144 | N/A | 148 | -3 | 0.9998 | 147.6 | -58.5 | -0.9296 | No | 51.6 |
| J1096 | 150 | ±25.144 | N/A | 148 | -2.9 | 0.9998 | 147.5 | -59.7 | -0.927 | No | 51.5 |
| J1102 | 70.0 | ±28.555 | 1 x 8 MVAr Cap | 68.7 | 27.5 | 0.9284 | 68.2 | -43.9 | -0.8409 | Yes | |
| J1107 | 200.0 | ±87.7 | 2 x 14 MVAr Cap | 197.4 | 82.2 | 0.9232 | 196.2 | -142.2 | -0.8097 | Yes | |
| J1115 | 200.0 | ±65.793 | 4 x 15 MVAr Cap | 195.8 | 112.5 | 0.8671 | 194.3 | -106.3 | -0.8773 | Yes | |
| J1139 | 151.2 | ±95.3400 | N/A | 149.4 | 74.0 | 0.8961 | 148.6 | -127.8 | -0.7582 | Yes | |
| J1145 | 250.0 | ±119.07 | N/A | 246.5 | 68.0 | 0.9640 | 244.4 | -200.6 | -0.7730 | No | 13.0 |
| J1152 | 200.0 | ±94.3 | N/A | 196.6 | 52.1 | 0.9666 | 194.4 | -163.8 | -0.7647 | No | 12.5 |
| J1180 | 75.0 | ±65.233 | 4 x 6 MVAr Cap<br>1 x 6 MVAr Inductor | 73.8 | 86.8 | 0.6478 | 73.2 | -86.9 | -0.6442 | Yes | |
| J1182 | 250.0 | ±82.1710 | N/A | 248.3 | 60.8 | 0.9713 | 248.1 | -107.2 | -0.9180 | No | 20.8 |
| J1189 | 4.95 | 0.0 | N/A | 4.9 | 0.3 | 0.9948 | 4.9 | 0.5 | -0.9948 | No | 1.3 |
| J956 | 200.6 | ±97 | N/A | 197.9 | 68.1 | 0.9456 | 196.9 | -141.3 | -0.8124 | Yes | |
| J968 | 200 | 66 | 2 x 14 MVAr Cap | 196.7 | 66.5 | 0.9473 | 195.6 | -105.1 | -0.8809 | Yes | |
| J974 | 225 | 82.5 | 1 x 14 MVAr Cap | 225 | 63.1 | 0.9629 | 223.7 | -129.4 | -0.8656 | No | 10.9 |
| J976 | 300.0 | ±146.4 | 2 x 4 MVAr Cap | 293.7 | 98.3 | 0.9483 | 289.9 | -238.9 | -0.7717 | Yes | |
| J979 | 170.0 | ±56.1 | 2 x 19 MVAr Cap | 167.4 | 75 | 0.9126 | 166.6 | -91.7 | -0.8761 | Yes | |
| J987 | 100.0 | ±44.24 | 2 x 7 MVAr Cap | 98.8 | 42.2 | 0.9196 | 98.2 | -70.1 | -0.8139 | Yes | |
| J991 | 150.0 | ±66.36 | 2 x 14 MVAr Cap | 148.5 | 78.4 | 0.8843 | 148.1 | -92.7 | -0.8476 | Yes | |
| J992 | 200.0 | ±88.48 | 2 x 14 MVAr Cap | 197.5 | 82.7 | 0.9224 | 196.2 | -146.3 | -0.8017 | Yes | |
| J993 | 200.0 | ±88.48 | 2 x 14 MVAr Cap | 197.3 | 81.1 | 0.9249 | 196.0 | -145.3 | -0.8033 | Yes | |
| J994 | 100.0 | ±44.24 | 2 x 7 MVAr Cap | 98.8 | 40.8 | 0.9243 | 98.0 | -73.5 | -0.8000 | Yes | |

## 3. Model Development and Study Assumptions

### 3.1. Base Case Models

The origin of the DPP 2018 April Central models is the MTEP 18 models with the Bench Cases including all pre-queued projects and associated network upgrades, while the Study Cases contain all of the interconnection requests in DPP 2018 April Central Phase III, in addition to all the facilities in the Bench Cases.

- Bench Cases
  - APR18-2023SH-Bench_Discharging_Phase_3 Final 041421.raw
  - APR18-2023SUM-Bench_Discharging_Phase_3 Final 041421.raw
- Study Cases
  - APR18-2023SH-Study_Charging_Phase_3 Final 041421.raw
  - APR18-2023SUM-Study_Charging_Phase_3 Final 041421.raw
  - APR18-2023SH-Study_Discharging_Phase_3 Final 041421.raw
  - APR18-2023SUM-Study_Discharging_Phase_3 Final 041421.raw

### 3.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

### 3.3. Contingencies

The following contingencies were considered in the steady state analysis:
1) NERC Category P0 (system intact -- no contingencies)
2) NERC Category P1 contingencies
   a. Single element outages, at buses with a nominal voltage of 68 kV and above
   b. Multiple element NERC Category P1 contingencies
3) NERC Category P2-P7 contingencies
4) For all the contingencies 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.

### 3.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2018 April Central generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.7.0 and TARA version 1902.

### 3.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the

applicable rating (normal or emergency) of the overloaded facility, or

4) For any other constrained facility, where none of the Study Generators meet one of the above criteria, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) will be responsible for mitigating the cumulative MW impact constraint, or
5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or
6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

1) The bus voltage is outside of the 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 generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of Interconnection Service. Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the Deliverability algorithm, to meet the system performance criteria for NERC category P1 events, if DFAX due to the study generator is equal to or greater than 5%.

## 4. Thermal Analysis

The thermal analysis results for 2018 April show generator projects J955, J979, J1025, J1063, and J1182 causing constraints. The details pertaining to the thermal analysis can be found in Appendix A – Ameren System Impact Study Report (CEII) and Appendix C – MISO ERIS Analysis (CEII).

NIPSCO LPC criteria was screened for in MISO's ERIS analysis and did not yield any actionable constraints.

## 5. Voltage Analysis

The voltage analysis results for 2018 April show that the study generators do not cause any voltage violations. The details pertaining to the voltage analysis can be found in Appendix C – MISO ERIS Analysis (CEII).

## 6. Stability Analysis

The MISO DPP Stability analysis shows that the study projects did not adversely impact the system.

An additional stability study capturing the Ameren Local Planning Criteria (LPC) for new generation interconnections was also performed by Ameren and also shows that study projects did not adversely impact the system under the Ameren LPC for new generation interconnections. The details pertaining to the stability analysis can be found in Appendix F – MISO Stability Analysis (CEII) and Appendix G – Ameren Stability Analysis (CEII).

### 6.1. Model Development

The following summer/shoulder discharging 2023 models were developed based on Phase III study models. The Ameren LPC stability models were also developed based on the Phase III stability study models and were adjusted in order to comply with Ameren's LPC by fully dispatching nearby local generation.

- Bench Cases:
    - APR18-2023SH-Bench_Discharging_Phase_3 Final 041421.raw
    - APR18-2023SUM-Bench_Discharging_Phase_3 Final 041421.raw
- Study Cases:
    - APR18-2023SH-Study_Discharging_Phase_3 Final 041421.raw
    - APR18-2023SUM-Study_Discharging_Phase_3 Final 041421.raw

### 6.2. Study Methodology

The purpose of the study is to identify potential angular instabilities, voltage dip violations, and damping violations, if any, due to the interconnection of the projects in the DPP 2018 April Central study cycle under disturbance conditions, and the impact of all study projects on the system stability performance.

The MISO fault scenarios simulated in this study cover faults simulated as part of the MTEP18 analysis as well as selected three-phase (3PH) faults with normal clearing and single line to ground (SLG) faults with delayed clearing. Dynamic simulations of fault scenarios were performed using the DSATools TSAT program (version 18.0.10).

The Ameren fault scenarios that were simulated in their LPC study were created by Ameren and are localized around each study projects POI. The fault said Ameren used were not based off of the MTEP18 stability package. Ameren also used PSS/E to run the stability analysis.

Fault scenarios were first simulated using the study case and the results were reviewed. For scenarios that exhibited instability, the bench case was simulated such that the stability performance with and without the proposed interconnection projects could be compared. Any new stability problems attributed to the proposed interconnection projects are flagged and reported.

For each fault, rotor angles, speed deviation, and electrical power outputs of the study generators and the generators in the proximity were monitored. Voltages at selected buses, including all POI buses of the study projects and all future buses, were also monitored.

Additional Ameren LPC criteria is listed in section 6.3 below.

NIPSCO LPC criteria studying in MISO's ERIS analysis includes a 3% DF cutoff, or MW Impact from study generator greater to 3% of facility rating in GI studies for elements the NIPSCO TO area.

### 6.3. Study Criteria

The transient stability study criteria that was used as part of this study is based upon 2 sets of guidelines:

<u>Ameren's Transmission Planning Criteria and Guidelines</u>

Ameren Transmission Planning Criteria and Guidelines prescribe the fault scenarios that should be evaluated in a transient stability and a small signal stability analysis.  These criteria state that plant transmission outlet is considered adequate, from the standpoint of stability, if the following conditions are met:

1. With all lines in service, the plant and remainder of the system shall remain stable when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.

2. With all lines in service, the plant and the remainder of the system shall remain stable when a

sustained single-line-to-ground fault on any two circuits of a multiple circuit tower line is cleared in primary clearing time.

3. With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained three-phase fault on any of the remaining outlet facilities is cleared in primary clearing time.

4. With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained double-line-to-ground (2-L-G) fault on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker".

Ameren's transient voltage recovery criteria states that "following clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 85% of nominal or greater within fifteen seconds".

MISO's Transmission Planning Criteria and Guidelines:

All renewable study projects are subject to the voltage ride-through and frequency ride-through criteria specified in NERC PRC-024-2 ("Generator Frequency and Voltage Protective Relay Settings") to check if the projects remain connected during frequency and voltage excursions. Specifically, PRC-024-2 mandates that protective relaying should be set in such a way that:

- Voltage Ride-Through: a generator shall withstand zero voltage at the POI (typically the primary side of the station transformer) for up to 0.15 seconds (9 cycles) and the ensuing voltage recovery period for three phase faults.
- Frequency Ride-Through: a generator shall maintain continuous operation between 59.5 and 60.5 Hz.

### 6.4. Study Results

Ameren Stability Results:

Based on the simulations performed in this study, the performance of the MISO projects J955, J976, J979, J987, J991, J994, J1022, J1026, J1055, J1107 and J1115 were found be acceptable under the fault scenarios prescribed by the Ameren Planning Criteria and Guidelines.

Projects J1087, J1094 and J1096 may also be deemed to have acceptable performance if the frequency relay protection settings can be adjusted to allow the generators to ride through the Ameren prescribed fault scenarios. J991 will be subject to the local Xenia operating guide and will not be allowed to operate when it is active.

Ameren was not able to evaluate the voltage and frequency ride-through capability of MISO projects J956, J1033, J1039 and J1139 because the generator customer did not provide data to model voltage and frequency relays.

MISO projects J974, J1102, J1145 and J1180 will be required to implement STATCOMs or similar devices since they were not able to ride-through the fault scenarios evaluated or were not able to maintain acceptable voltage profiles after the fault was cleared.

MISO project J1025 performance was found to be acceptable with the withdrawal of projects J966 and J1177 and an election change to project J1182.

There were no violations of Ameren's transient voltage recovery criteria at transmission buses. A few violations occurred at distribution buses which do not require mitigation. No issues with nearby synchronous generators were observed. The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix G – Ameren Stability Analysis (CEII).

MISO Stability Results:

No network upgrades were identified or assigned to any study projects. Only some model tuning is needed for specific projects prior to moving onto Phase 3.

J1055 summer plots observed oscillation issues associated with the Torque control model. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1069's Generic Renewable Drive Train Model need tuning as would not run. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

Some of J1022 summer plots observed oscillation issues. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

J1055, J968, J974, and J1087 tripped offline for various fault simulations. Relay protection models may need to be tuned to prevent this occurrence. Model tuning needed prior to Phase 3 kickoff. No network upgrades were required.

The complete list of 3PH and SLG faults simulated as well as their corresponding results and plots are included in Appendix F – MISO Stability Analysis (CEII).

## 7. Short Circuit Analysis

The short circuit analysis results for 2018 April show that the study generators do not cause any short circuit violations. The details pertaining to the short circuit analysis can be found in Appendix H – Short Circuit Study Analysis (CEII).

## 8. Affected System Impact Study

The details pertaining to the AECI, PJM, SPP, and TVA Affected Systems studies are in Appendix I – AECI Affected Systems Study Report (CEII), Appendix J – PJM Affected Systems Study Report (CEII), Appendix K – SPP Affected Systems Study Report (CEII), Appendix L – TVA Affected Systems Study Report (CEII).

### 8.1. J955

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 21.20% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of $2.5 million. The project is allocated 89.84% of the cost. The MISO portion of this upgrade has been classified as an ERIS upgrade and costs assigned reflect this, and the MISO TO for the NU is AMIL.

3. AD1-133 - Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to perform sag mitigation, upgrade station conductor, upgrade 2 breakers, 2 disconnect switches, and CTs with a cost estimate of $20.5 million. The project is allocated 100% of the cost.

4. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of $5 million. The project is allocated 50.24% of the cost.

### 8.2. J956

No affected systems mitigations were found to be required for this generator.

### 8.3. J968

No affected systems mitigations were found to be required for this generator.

### 8.4. J974

The PJM Study identified that this generator contributes to the following constraints:

1. Goodings 3B – Goodings 4B 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 345 kV circuit breaker and station conductor with a cost estimate of $3.2 million. The project is allocated 100% of the cost.

2. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $6.925 million. The project is allocated 5.98% of the cost.

3. Crete – St. John 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $11.2 million. The project is allocated 1.19% of the cost. The second portion of the upgrade will replace a 345 kV breaker and associated equipment at Crete with a cost of $6 million. The project is allocated 2.22% of the cost.

4. Wilton R – Wilton 3M 765 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to build-out and relocate the Wilton 765 kV bus and install 2 new breakers with a cost estimate of $12 million. The project is allocated 1.82% of the cost.

5. East Frankford – Crete 345 kV

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the 161 kV jumpers for the transformer with a cost estimate of $10.3 million. The project is allocated 6.58% of the cost.

### 8.5. J976
No affected systems mitigations were found to be required for this generator.

### 8.6. J979
The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 4.39% of the cost.

2. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate line sag with a cost estimate of $10.5 million. The project is allocated 16.52% of the cost.
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### 8.7. J987
No affected systems mitigations were found to be required for this generator.

### 8.8. J991
The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 5.96% of the cost.

### 8.9. J992
No affected systems mitigations were found to be required for this generator.

### 8.10. J993
No affected systems mitigations were found to be required for this generator.

### 8.11. J994
No affected systems mitigations were found to be required for this generator.

### 8.12. J1022
The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 3.03% of the cost.

### 8.13. J1025

No affected systems mitigations were found to be required for this generator.

### 8.14. J1026

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 50.5% of the cost.

### 8.15. J1027

No affected systems mitigations were found to be required for this generator.

### 8.16. J1028

No affected systems mitigations were found to be required for this generator.

### 8.17. J1034

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 48.5% of the cost.

### 8.18. J1055

The PJM Study identified that this generator contributes to the following constraints:

1. AB-122 – Dresden 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the line with a cost estimate of $6.925 million. The project is allocated 2.16% of the cost.

### 8.19. J1058

The PJM Study identified that this generator contributes to the following constraints:

1. St John – St John Tap 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of $20.8 million. The project is allocated 17.55% of the cost.

2. St John Tap – Greenacre 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor the ComEd portion of the line with a cost estimate of $7.9 million. The project is allocated 17.55% of the cost.

3. Greenacre Tap – Olive 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate the sag on the ComEd portion of the line with a cost estimate of $13.9 million. The project is allocated 8.96% of the cost.

### 8.20. J1067

No affected systems mitigations were found to be required for this generator.

### 8.21. J1069

No affected systems mitigations were found to be required for this generator.

### 8.22. J1087

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 25.05% of the cost.

### 8.23. J1094

No affected systems mitigations were found to be required for this generator.

### 8.24. J1096

No affected systems mitigations were found to be required for this generator.

### 8.25. J1102

No affected systems mitigations were found to be required for this generator.

### 8.26. J1107

The AECI Study identified that this generator contributes to the following constraints:

1. Green Forest – Township 69 kV Line

Per AECI cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add reconductor the Green Forest – Township 69 kV line with a cost estimate of $2,895,000. The project is allocated 17.07% of the cost.

### 8.27. J1115

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 3.57% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of $9.1 million. The project is allocated 27% of the cost.

### 8.28. J1139

The PJM Study identified that this generator contributes to the following constraints:

1. J1180 – Sullivan 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to add a second 345 kV branch, bus expansions, and 345 kV breakers with a cost estimate of $5 million. The project is allocated 4.31% of the cost.

2. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (MISO End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned MISO upgrade is to replace the limiting terminal equipment with a cost estimate of $2.5 million. The project is allocated 10.16% of the cost. The MISO portion of this upgrade has been classified as an ERIS upgrade and costs assigned reflect this, and the MISO TO for the NU is AMIL

3. Brokaw- AD2-153 Tap – AB2-047 Tap 345 kV Overload (ComEd End)

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned ComEd upgrade is to replace 2-345kV circuit breakers, mitigate line sag, station conductor with relay package with a cost estimate of $9.1 million. The project is allocated 73% of the cost.

4. Z2-087 Tap – Pontiac R 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to mitigate line sag with a cost estimate of $10.5 million. The project is allocated 83.48% of the cost.

5. Pontiac - Loretto 345 kV Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to replace the Pontiac 345 kV breaker and replace 345 kV disconnect switch with a cost estimate of $5 million. The project is allocated 5.03% of the cost.

### 8.29. J1145

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 23.3% of the cost.

### 8.30. J1180

No affected systems mitigations were found to be required for this generator.

### 8.31. J1182

The PJM Study identified that this generator contributes to the following constraints:

1. Austin - Kincaid 345 kV Ckt 1 Overload

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the listed constraint. The planned upgrade is to reconductor 5.02 miles of the MISO/Ameren owned line with a cost estimate of $8 million. The project is allocated 26.2% of the cost.

### 8.32. J1189

No affected systems mitigations were found to be required for this generator.

## 9. Deliverability Analysis

### 9.1. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an Energy Resource (ER) project or to proceed with the system upgrades that will make the generator fully deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100% of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C.

### 9.2. Determining the MW Restriction

If one facility is overloaded based on the assessed “severe yet credible dispatch” scenario described in the study methodology, and the generator under study has a DF greater than 5%, part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

If the result is larger than the maximum output of the generator, 100% of this generator’s output is not deliverable.

### 9.3. Deliverability Study Results

The limiting constraints (mon-con pairs) seen in the deliverability analysis for the 2018 Summer case are summarized in Appendix D - Deliverability Analysis (CEII).

#### 9.3.1. J955

This generator is found to be fully deliverable for 1165 MW without any network upgrades.

#### 9.3.2. J956

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.3. J968

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.4. J974

This generator is found to be fully deliverable for 250 MW without any network upgrades.

#### 9.3.5. J976

This generator is found to be fully deliverable for 300 MW without any network upgrades.

#### 9.3.6. J979

This generator is found to be fully deliverable for 170 MW without any network upgrades.

#### 9.3.7. J987

This generator is found to be fully deliverable for 170 MW without any network upgrades.

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#### 9.3.8. J991

This generator is found to be fully deliverable for 150 MW without any network upgrades.

#### 9.3.9. J992

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.10. J993

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.11. J994

This generator is found to be fully deliverable for 100 MW without any network upgrades.

#### 9.3.12. J1022

This generator is found to be fully deliverable for 150 MW without any network upgrades.

#### 9.3.13. J1025

This generator is found to be fully deliverable for 290 MW without any network upgrades.

#### 9.3.14. J1026

This generator is found to be fully deliverable for 170 MW without any network upgrades.

### 9.3.15. J1027

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 6 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 6: NRIS Results for J1027**

| J1027 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 0 | 5.00% | No | - | J1027, J1028, J1074, J1152 | 1,280,228 | 6,000,000 |
| J829 – Dresser 345kV Line | 150 | 5.99% | No | - | J1027, J1028, J1074, J1189 | 10,155,153 | 45,500,000 |

### 9.3.16. J1028

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 7 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 7: NRIS Results for J1028**

| J1028 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 0 | 6.14% | No | - | J1028, J1074, J1152 | 1,285,349 | 6,000,000 |
| J829 – Dresser 345kV Line | 150 | 6.22% | No | - | J1016, J1074, J1028, J1027, J1189 | 9,198,791 | 45,500,000 |

### 9.3.17. J1034

This generator is found to be fully deliverable for 225 MW without any network upgrades.

### 9.3.18. J1055

This generator is found to be fully deliverable for 144 MW without any network upgrades.

### 9.3.19. J1058

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.20. J1063

This generator is determined to be fully deliverable for 134.42 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 8 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 8: NRIS Results for J1063**

| J1063 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 140.18 MW (71.89%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associate d with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| Clarkshill – Thorntown 69 kV | 195 | 9.97% | No | - | J1063 | 18,954,200 | 18,954,200 |

### 9.3.21. J1067

This generator is found to be fully deliverable for 240 MW without any network upgrades.

### 9.3.22. J1069

This generator is found to be fully deliverable for 200 MW without any network upgrades.

### 9.3.23. J1074

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 9 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 9: NRIS Results for J1074**

| J1074 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 0 | 5.03% | No | - | J1028, J1074, J1152 | 1,717,212 | 6,000,000 |
| J829 – Dresser 345kV Line | 200 | 10.89% | No | - | J1027, J1028, J1074, J1189 | 24,616,497 | 45,500,000 |

#### 9.3.24. J1087

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.25. J1094

This generator is found to be fully deliverable for 150 MW without any network upgrades.

#### 9.3.26. J1096

This generator is found to be fully deliverable for 150 MW without any network upgrades.

#### 9.3.27. J1102

This generator is found to be fully deliverable for 70 MW without any network upgrades.

#### 9.3.28. J1107

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.29. J1115

This generator is found to be fully deliverable for 200 MW without any network upgrades.

#### 9.3.30. J1139

This generator is found to be fully deliverable for 135 MW without any network upgrades.

#### 9.3.31. J1145

This generator is found to be fully deliverable for 250 MW without any network upgrades.

#### 9.3.32. J1152

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 10 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 10: NRIS Results for J1152**

| J1145 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| McKnight – Coly 500kV Line | 200 | 5.03% | No | - | J1028, J1074, J1152 | 1,717,212 | 6,000,000 |

#### 9.3.33. J1180

This generator is found to be fully deliverable for 75 MW without any network upgrades.

#### 9.3.34. J1182

This generator is found to be fully deliverable for 250 MW without any network upgrades.

#### 9.3.35. J1189

This generator is determined to be fully deliverable for 0 MW, contingent upon the system upgrades and contingent facilities identified in the NRIS analysis. Table 11 shows the NRIS results and cost estimates determined in the NRIS analysis.

**Table 11: NRIS Results for J1189**

| J1189 Deliverable (NRIS) Amount in 2018 Case: (Conditional on ERIS and case assumptions) | 0 MW (0%) |
|---|---|

| Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS) | Level of Service Attainable (MW) | Distribution Factor | Constraint in ERIS Analysis? | Projects Associated with ERIS Constraint | Projects Associated with NRIS Constraint | Upgrade Cost Allocated to Project | Total Cost of Upgrade ($) |
|---|---|---|---|---|---|---|---|
| J829 – Dresser 345kV Line | 4.95 | 5.70% | No | - | J1027, J1028, J1074, J1189 | 318,896 | 45,500,000 |

## 10. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) Analysis tests for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study.

The maximum MW impacts and Shared Network Upgrade (SNU) cost allocations appear in Table 12.

**Table 12: Maximum MW Impact and SNU Cost Allocations**

| Network Upgrades | Project Study Cycle | Projects sharing cost | MW Contribution | Total NU Cost ($) | Cost Responsibility ($) |
|---|---|---|---|---|---|
| N/A | N/A | N/A | N/A | N/A | N/A |

## 11. Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

### 11.1. Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade identified in System Impact Study was provided by the corresponding transmission owning company.

### 11.2. Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case.

<u>Cost Allocation Methodology for Thermal Constraints</u>

1. With all Study Group generation projects dispatched in the Post Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of one NU is:

$$\begin{aligned}&Project\ A\ cost\ portion\ of\ NU\\&Cost\ of\ NU = \frac{Max(Proj.A\ MW\ contribution\ on\ constraint)}{\sum_i Max(Proj.i\ MW\ contrution\ on\ constraint)}\end{aligned}$$

6. The total NU costs for each project are calculated if more than one NU is required.

**Appendix A – Ameren System Impact Study Report (CEII)**

**Appendix B – Cost Allocation Summary (CEII)**

**Appendix C – MISO ERIS Analysis (CEII)**

**Appendix D – MISO Deliverability Analysis (CEII)**

**Appendix E – Network Upgrades Per Project (CEII)**

**Appendix F – MISO Stability Analysis (CEII)**

**Appendix G – Ameren Stability Analysis (CEII)**

**Appendix H – Short Circuit Study Analysis (CEII)**

**Appendix I – AECI Affected Systems Study Report (CEII)**

**Appendix J – PJM Affected Systems Study Report (CEII)**

**Appendix K – SPP Affected Systems Study Report (CEII)**

**Appendix L – TVA Affected Systems Study Report (CEII)**

**Appendix M – MISO A10 Results (CEII)**

# <u>WHITE COUNTY</u>
# <u>DECOMMISSIONING PLAN AGREEMENT</u>

This Decommissioning Plan Agreement (“**Agreement**”) dated as of July 5, 2022 (“**Effective Date**”) by and between Cavalry Energy Center, LLC, a Delaware limited liability company, qualified to do business in Indiana (“**Company**”), and White County, Indiana (“**County**”).

## RECITALS

**WHEREAS**, Company desires to build a commercial solar energy system project in White County, Indiana (the “**Project**”);

**WHEREAS**, Company has or will enter into certain Lease Agreements (collectively, the “**Leases**”) with the landowners within the Project area (the “**Landowners**”) to install certain Project facilities on the real estate of the Landowners (each, a “**Property**”);

**WHEREAS**, Company shall present a Decommissioning Plan to County for approval prior to issuance of an Improvement Location Permit (the “**Plan**”);

**WHEREAS**, Company shall post a performance or surety bond or letter of credit for decommissioning costs upon the terms and conditions more fully set forth below; and

**WHEREAS**, for purposes of this Agreement, “**Generating Units**” are defined to include, but not be limited to, solar panels, racks, inverters, piles, foundations, transformers and underground cable circuits.

**NOW, THEREFORE**, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereby agree as follows:

## <u>ARTICLE I</u>
## <u>RESTORATION FUND ISSUANCE</u>

Section 1.1 <u>Agreement to Decommission; Restoration Fund Amount</u>.

a. Company shall decommission each Generating Unit and related improvements pursuant to the terms of this Agreement and the Plan related thereto described in <u>Attachment A</u> (Decommissioning Plan) attached hereto. Company shall decommission each Generating Unit and related improvements upon the discontinuation of use, which shall be deemed to occur upon (i) the failure of such Generating Units to produce electricity for twelve (12) consecutive months unless a plan outlining the steps and schedule for returning the Generating Units to service is submitted and approved by County within the twelve (12) month discontinuation period, or (ii) written notice from Company to County that decommissioning is otherwise commencing. Decommissioning shall include: (1) removal from each Property of each Generating Unit and related improvements installed or constructed by Company, (2) fill in and compact all trenches or other borings or excavations made by Company on each Property, (3) leave the surface of each Property free from debris, and (4) use reasonable efforts to restore each Property to farmable condition, as more particularly described in Attachment B (Agricultural Soil Reclamation Plan) attached hereto.

b. In the event of a force majeure or other event which results in the absence of electrical generation for twelve (12) consecutive months, by the end of the twelfth consecutive month of non-operation, Company must demonstrate to County that the Project will be substantially operational and producing electricity within twenty-four (24) months of the force majeure or other event. If such a demonstration is not made to County's reasonable satisfaction, the decommissioning must be initiated within eighteen (18) months after the force majeure or other event. The approval of County of such a plan may not be unreasonably withheld, conditioned or delayed. County considers a force majeure to be due to the following causes: acts of God, war, civil commotion, riots or damage to work in progress by reason of fire or other casualty, strikes, lock outs or other labor disputes, delays in transportation, inability to secure labor or materials in the open market, war, terrorism, sabotage, civil strife or other violence, improper or unreasonable acts or failures to act by County, the failure of any governmental authority to issue any permit, entitlement, approval or authorization within a reasonable period of time after a complete and valid application for the same has been submitted, the effect of any law, proclamation, action, demand or requirement of any government agency or utility, or litigation contesting all or any portion of the right, title and interest of County or Company under this Agreement. The obligation of Company to maintain the Restoration Fund (as defined below) under this Agreement shall not be affected by the occurrence of such a force majeure or other event.

At the time of making application for an Improvement Location Permit ("**ILP**"), Company shall deliver to County a performance or surety bond or letter of credit in a form and substance reasonably satisfactory to County (the "**Restoration Fund**") securing performance of the Decommissioning Obligations (as defined below), which shall be equal to the estimated amount of removal costs of the Generating Units, if any, including reasonable professional fees related thereto and accounting for salvage value (the "**Net Removal Cost**"). Company shall retain a professional engineer licensed in Indiana with knowledge of the operation and decommissioning of solar projects (a "**Professional Engineer**") to provide an estimate of the Net Removal Cost, which Professional Engineer shall be subject to approval of County, which approval shall not be unreasonable withheld, conditioned or delayed. If the Parties cannot agree on the Professional Engineer, then County and Company shall each select a Professional Engineer (together, the "**Other Engineers**"), each of which shall provide an estimate of the Net Removal Cost. The amount of the Restoration Fund shall be an amount equal to either (i) the estimate of the Net Removal Cost provided by the Professional Engineer (if applicable), or (ii) the average of the two (2) estimates of the Net Removal Cost provided by the Other Engineers, either of which shall include a reasonable adjustment for inflation. For purposes of estimating the salvage value, in the event the Generating Units are encumbered by a lien or security interest for the benefit of a lender or creditor of Company or other party (other than County), the Generating Units shall be deemed to have salvage value only to the extent that the salvage value of the Generating Units exceed the amount of the lien or security interest. Each party shall pay its respective fees in obtaining the estimates of the Net Removal Cost. Company shall keep the Restoration Fund, or a like replacement financial assurance, in force throughout the remainder of the term of this Agreement, as set forth in Section 1.3 below. Notwithstanding the foregoing provisions of Section 1.1, the initial Restoration Fund shall be $7,000,000.00, which the County accepts, plus the County's reasonable professional fees related thereto.

Section 1.2 Restoration Fund Provider; Restoration Fund Beneficiaries. At least thirty (30) days prior to such delivery of the Restoration Fund to County, Company shall submit to the Board of Commissioners the name of the rated provider of the Restoration Fund and a specimen security document. County shall be named as the beneficiary of the Restoration Fund; provided, however, that the disbursement of and rights to the Restoration Fund shall be governed by Article II below; and provided further, that the Landowners may also be beneficiaries of the Restoration Fund. Company represents that it has not granted and Company shall not grant to the Landowners or any other party rights to the Restoration Fund senior to the rights of County to the Restoration Fund. The provider of the Restoration Fund shall be (i) if a surety, a company listed in the latest version of "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reimbursing Companies", (ii) if a letter of credit, a bank with a "A3" or higher rating from Moody's Investors Service, Inc., or a comparable rating from Standard & Poor's.

Section 1.3 Restoration Fund Requirements. After the initial five (5) year term and each five (5) years thereafter for the duration of the operation of the Project, Company shall deliver to County not later than ninety (90) days prior to the expiration date of any posted Restoration Fund (the "**Renewal Deadline**"), a certificate of continuation extending the expiration date of the then-existing Restoration Fund for an additional period based on current industry practices, be it an annual renewal or otherwise. Such certificate of continuation shall include an updated estimate of the Net Removal Cost determined by the same method set forth in Section 1.1(c) (using the same Professional Engineer or Other Engineers, if available). Company shall provide County written notice no later than ninety (90) days prior to the Renewal Deadline that the Renewal Deadline is approaching and that a certificate of continuation is forthcoming pursuant to the terms of this Section 1.3. A new Restoration Fund, in the revised amount, if any, shall be provided sixty (60) days prior to the Renewal Deadline. However, in the event Company desires to install electrical storage capacity as part of the Project in the future, Company shall first provide the County with written notice of its desire to do so with detailed plans and specifications of its intended installation and equipment (the "**Electric Storage Plan**"). County shall be provided sixty (60) days to review the Electric Storage Plan, within which time County may require an updated estimate of the Net Removal Cost prepared by a Professional Engineer or Other Engineers, if available, pursuant to the terms of this Section 1.3. A new Restoration Fund, in the revised amount, if any, shall be provided sixty (60) prior to the installation of Company's electrical storage equipment. If such a new Restoration Fund is provided, then Company shall instead provide for the duration of the operation of the Project the certificate of continuation and updated Net Removal Cost estimates each five (5) years thereafter in the manner set forth in this Section 1.3.

Section 1.4 Failure to Provide Restoration Fund. If Company fails to provide the Restoration Fund or the certificate of continuation provided in Section 1.2 and Section 1.3, County shall provide written notice to Company and Company and its lender of record in County shall be afforded thirty (30) days' notice and opportunity to cure, prior to County's declaring a default under this Agreement. If Company or its lender fails to provide the Restoration Fund or the certificate of continuation provided in Section 1.2 and Section 1.3 after such thirty (30) days (including notice to Company's lender) and County declares an event of default hereunder, County shall have the right to (a) seek any necessary injunctive relief available under applicable law to affect the providing of the Restoration Fund or any other requirement under this

Agreement, (b) pay any premium necessary to continue the Restoration Fund, in which case Company shall reimburse County for the amount of such premium, (c) draw on the Restoration Fund and deposit the drawn funds in a bank account and, at County's election, apply such funds to the decommissioning of the Generating Units, and (d) seek all remedies at law. Company shall pay to County all reasonable attorney and professional fees and other costs incurred by County with respect to the pursuit and implementation of such remedies for such an event of default.

## ARTICLE II
## DISBURSEMENT OF SECURITY

Section 2.1 Rights of County. In the event Company fails to decommission the Project in accordance with the requirements of this Agreement and the White County Zoning Ordinance (the "**Ordinance**"), County may, in its sole election, undertake the decommissioning of the Project. County's election to decommission all or any portion of the Project shall not release any obligation of the Landowners, Company or any other third party to complete the decommissioning of the entire Project. In the event County elects to undertake the decommissioning of the Project, it may make a claim(s) upon the Restoration Fund to the Restoration Fund provider for the Net Removal Cost subject to the limitations set forth herein. Any claim made by County upon the Restoration Fund shall be limited to such expenses incurred by County for the removal of all structures and the restoration of the soil and vegetation with the Project, as set forth in this Agreement and the Ordinance, including reasonable professional fees (the "**Decommissioning Obligations**").

Section 2.2 County Cooperation. In the event County elects not to undertake or complete the decommissioning of all or any portion of the Project, County shall execute all documentation reasonably required or requested by the Restoration Fund provider, Company and/or its lenders necessary to waive County's rights to all or a portion of the Restoration Fund funds and to otherwise permit the Landowners to make claims against the Restoration Fund or at the option of the Landowners, return the Restoration Fund to Company. Additionally, County and Landowners may enter into a "Letter of Understanding" (in recordable form) by which certain Project facilities such as access roads and out buildings, as deemed necessary or useful by Landowners, may be allowed to remain.

Section 2.3 Landowner Leases. Company represents and agrees that all Leases for Generating Units shall contain terms that provide that the Generating Units are properly decommissioned upon expiration or earlier termination of the Project (except as otherwise allowed under Section 1.1 hereof or specifically provided in a Lease); provided, however, delivery of such terms of the Leases shall not relieve Company of any of its obligations under this Agreement. Prior to assisting with or consenting to any decommissioning activities with Landowner, Company must contact County and obtain written confirmation that County has affirmatively elected to not undertake the decommissioning and is waiving its right to the Restoration Fund.

Section 2.4 Release of Restoration Fund. The Restoration Fund provider shall release the Restoration Fund when Company has demonstrated to the reasonable satisfaction of County that the Decommissioning Obligations have been satisfied.

## ARTICLE III

SALVAGE VALUE

Section 3.1 County Right to Salvage Value of Generating Units. In the event Company, its lenders or the Landowners fail to decommission the Project in accordance with the terms of the Ordinance and this Agreement and County elects to undertake the decommissioning of the Project in accordance with Section 2.1, in addition to any rights County has to make a claim upon the Restoration Fund, the Generating Units within the Project shall be deemed abandoned and County shall be entitled to apply the salvage value of the Generating Units located within the Project to any costs of decommissioning the Project in excess of the funds available under the Restoration Fund.

## ARTICLE IV
## OTHER RIGHTS OF COUNTY

Section 4.1 Other Relief. In addition to any other rights and remedies granted herein, County shall have the right to seek any injunctive relief available under applicable law to effect or complete the decommissioning of the Project. In addition, County shall have the right to seek reimbursement from Company, its successors or assigns, for any costs of decommissioning the Project incurred by County in excess of the funds available under the Restoration Fund and the salvage value of the Generating Units.

## ARTICLE V
## REPRESENTATIONS AND WARRANTIES

Section 5.1 Representations, Warranties and Covenants of County. County represents and warrants to Company as follows:

a. County has full power and authority, on behalf of County, to deliver and perform this Agreement and to take all actions necessary to carry out the transactions contemplated by this Agreement.

b. This Agreement has been duly executed and delivered by County and constitutes the legal, valid and binding obligation of County, enforceable against County in accordance with its terms.

c. The execution, delivery, and performance of this Agreement by County will not, to the best of County's knowledge, violate any applicable law of the State of Indiana.

Section 5.2. Representations, Warranties and Covenants of Company. Company represents and warrants to County as follows:

a. Company has full power and authority to execute, deliver and perform this Agreement and to take all actions necessary to carry out the transactions contemplated by this Agreement.

b. This Agreement has been duly executed and delivered by Company and constitutes the legal, valid and binding obligation of Company, enforceable against Company in accordance with its terms.

## ARTICLE VI
## DEFAULT; DISPUTES

Section 6.1 Default; Disputes. The breach of or default under this Agreement by Company (after appropriate written notice from County and opportunity to cure by Company) shall invoke remedies set forth under the Ordinance which shall be in addition to the remedies set forth in this Agreement.

## ARTICLE VII
## TERM

Section 7.1 Term. The term of this Agreement shall commence on the Effective Date, and this Agreement and County's rights hereunder shall terminate upon the completion of the decommissioning of the Project in accordance with the terms of this Agreement. Upon termination of this Agreement, County shall execute all documentation necessary or reasonably required in order to release and waive all claims to the Restoration Fund and the salvage value of the Generating Units upon the request of Company.

## ARTICLE VIII
## MISCELLANEOUS

Section 8.1 No Waiver; Remedies Cumulative. No failure on the part of any party hereto to exercise, and no delay in exercising, any right, power or remedy shall operate as a waiver thereof. No single or partial exercise by any party hereto of any such right, power or remedy hereunder shall preclude any other further exercise of any right, power or remedy hereunder. The rights, powers and remedies herein expressly provided are cumulative and not exclusive of any rights, powers or remedies available under applicable law.

Section 8.2 Notices. All notices, requests and other communications provided for herein (including any modifications, or waivers or consents under this Agreement) shall be given or made in writing (including by telecopy) delivered to the intended recipient at the address set forth below or, as to any party, at such other address as shall be designated by such party in a notice to the other party. Except as otherwise provided herein, all notices and communications shall be deemed to have been duly given when transmitted by telecopier with confirmation of receipt received, personally delivered, or in the case of a mailed notice, upon receipt, in each case given or addressed as provided herein.

If to Company:
Cavalry Energy Center, LLC
c/o NextEra Energy Resources, LLC
700 Universe Boulevard
Juno Beach, Florida 33408
Attn: Business Manager

With a copy to:
Dentons Bingham Greenebaum LLP
2700 Market Tower, 10 West Market Street
Indianapolis, Indiana 46204
Attn: Matthew G. Nolley, Esq.

If to County:
Gayle Rogers
White County Auditor
110 N. Main Street, Suite 106
Monticello, Indiana 47960

All notices to County shall include a copy
to White County Attorney(s):
George W. Loy, Esq.
117 W. Broadway Street
Monticello, Indiana 47960

Section 8.3 Amendments. This Agreement may be amended, supplemented, modified or waived only by an instrument in writing duly executed by each of the parties hereto.

Section 8.4 Successors and Assigns.

a. This Agreement shall (i) remain in full force and effect until the termination hereof pursuant to Section 7.1 herein; and (ii) be binding upon and inure to the benefit of the respective successors and assigns of the parties hereto.

b. Except as provided in subsections (c), (d), (e) and (f) below, no party to this Agreement shall assign, transfer, delegate, or encumber this Agreement or any or all of its rights, interests, or obligations under this Agreement without the prior written consent of the other party. In those instances in which the approval of a proposed assignee or transferee is required or requested: (i) such approval shall not be unreasonably withheld, conditioned, or delayed; and (ii) without limiting the foregoing, County's approval may not be conditioned on the payment of any sum or the performance of any agreement other than the agreement of the assignee or transferee to perform the obligations of Company pursuant to this Agreement. For the avoidance of doubt, no direct or indirect change of control of the ownership interests of Company, or any other sale of direct or indirect ownership interests in Company (including any tax equity investment or passive investment) shall constitute an assignment requiring the consent of County under this Agreement.

c. Company may, without the consent of County, but with written notice to County, assign or transfer this Agreement, in whole or in part, or any or all of its rights, interests, and obligations under this Agreement to any affiliate or subsidiary or, with the consent of County (not to be unreasonably withheld, conditioned or delayed), a company or other entity that acquires substantially all of the assets of Company. So long as an assignee assumes in writing all assigned obligations under this Agreement, Company may (with the consent of County, not to be unreasonably withheld) be released from liability for the assigned obligations hereunder. Notwithstanding the above, with prior written notice to County but without the need for consent of County, Company may assign or transfer this Agreement, in whole or in part, or any or all of its rights, interests, and obligations under this Agreement, to a (i) public utility, or (ii) any other company or other entity, provided in instance (ii) that such assignee or an affiliated company shall have comparable experience to Company in constructing and operating a solar project in the United States and a net worth of a minimum of $10,000,000 as confirmed by audited financial statements as of the most recent fiscal year.

d. Company will not be required to obtain consent of County for or in connection with (i) a corporate reorganization of Company or any of its direct or indirect affiliates, or (ii) a sale or transfer of equity interest of any direct or indirect affiliate of Company.

e. Any transfer or assignment pursuant to this Section shall be subject to the assignee agreeing in writing to be bound by the terms of this Agreement. Any assignment of this Agreement by Company to an assignee shall be subject to Company assigning its rights and obligations under the Road Use Agreement between County and Company and dated of even date herewith (the "**Road Use Agreement**") and the Agreement for Economic Development Agreement between County and Company and dated of even date herewith (the "**Economic Development Agreement**") to the same assignee. Any notice of assignment required to be delivered by Company pursuant to this Section shall be in writing, shall set forth the basis for the assignment, including such supporting information as may be reasonably necessary to demonstrate compliance with this Section, and shall be delivered to County not less than forty-five (45) days after the effective date of the assignment.

f. Company may, also, without the prior approval of County, enter into any partnership or contractual arrangement, including but not limited to, a partial or conditional assignment of equitable interest in Company or its parent to any person or entity, including but not limited to tax equity investors, or by security, charge or otherwise encumber its interest under this Agreement for the purposes of financing the development, construction and/or operation of the Project (any of the foregoing actions, a "**Collateral Assignment**"), and County shall agree to execute and deliver any reasonably requested estoppels related to a Collateral Assignment. Promptly after making such encumbrance, Company shall notify County in writing of the name, address, and telephone and facsimile numbers of each party in favor of which Company's interest under this Agreement has been encumbered (each such party, a "**Financing Party**" and, together, the "**Financing Parties**"). Such notices shall include the names of the account managers or other representatives of the Financing Parties to whom all written and telephonic communications may be addressed. After giving County such initial notice regarding a Collateral Assignment, Company shall promptly give County notice of any change in the information provided in the initial notice or any revised notice. Company shall, in the event of any such Collateral Assignment, remain bound to the terms of this Agreement unless otherwise agreed by County.

g. Notwithstanding any provision contained in this Agreement to the contrary, including but not limited to Section 8.4, in no event shall an assignment be valid unless and until (i) there exists no breach of any covenants or obligations contained herein beyond any applicable notice and cure period, (ii) County receives notice of such assignment with current contact information for the assignee upon assignment, (iii) County receives a copy of the written undertaking of said rights and/or obligations by such entity or entities with said notice and copy of the written undertaking being due to County within forty-five (45) days after such assignment.

Section 8.5 Counterparts; Effectiveness. This Agreement may be executed in any number of counterparts, all of which when taken together shall constitute one and the same instrument and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement constitutes the entire agreement and understanding among the parties hereto with respect to matters covered by this Agreement and supersedes any and all prior agreements and understandings, written or oral, relating to decommissioning of the Project.

Section 8.6. Severability. If any provision hereof is invalid or unenforceable in any jurisdiction, then, to the fullest extent permitted by applicable law: (a) the other provisions hereof shall remain in full force and effect in such jurisdiction in order to carry out the intentions of the parties hereto as nearly as may be possible; and (b) the invalidity or unenforceability of any provision hereof in any jurisdiction shall not affect the validity or enforceability of such provision in any other jurisdiction.

Section 8.7 Headings. Headings appearing herein are used solely for convenience of reference and are not intended to affect the interpretation of any provision of this Agreement.

Section 8.8 Governing Law. This Agreement shall be governed by, and construed in accordance with the laws of the State of Indiana, without regard to its conflicts of laws provisions. Venue for any action related to this Agreement shall be in a court of appropriate jurisdiction located in White County, Indiana.

Section 8.9 Use of Roads. Not later than sixty (60) days prior to the commencement of decommissioning, Company shall post a surety bond or other security in a form or amount reasonably acceptable to County and Company to cover the costs of estimated damage to the County roads that may be incurred during the decommissioning of the Project.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]
[SIGNATURE PAGE(S) FOLLOW.]

IN WITNESS WHEREOF, this Agreement has been duly executed on the date and year first written above.

**"Company"**

**Cavalry Energy Center, LLC,**
a Delaware limited liability company

By: DocuSigned by: F5C968BD9C2148B
Anthony Pedroni, Vice President

**"County"**

**WHITE COUNTY, INDIANA**

**By: Board of Commissioners of White County, Indiana**

By: ______________________
David Diener, Commissioner

By: ______________________
Steve Burton, Commissioner

By: ______________________
James B. Davis, Commissioner

ATTEST:

______________________
County Auditor

# ATTACHMENT A

## DECOMMISSIONING PLAN

In accordance with the White County Zoning Ordinance - Solar Farms and Solar Energy Systems and the Decommissioning Plan Agreement dated July 5, 2022, Cavalry Energy Center, LLC ("**Company**") shall cause its commercial solar energy system project (the "**Project**") shall adhere to the following decommissioning plan. The procedures outlined herein are formulated to ensure public health and safety, environmental protection, and compliance with applicable laws and regulations. The procedures described identify the proposed activities to restore the site upon operation completion.

1. The Decommissioning Plan for the project consists of the following major elements:
   a. Documentation and establishment of health and safety requirements and procedures;
   b. Performance of pre-decommissioning planning activities such as updating the final decommissioning and restoration plans and schedules, as necessary, that address the pre-construction site conditions at the start of the Project;
   c. Dismantling and removal of improvements and materials;
   d. Remediation of soil as necessary; and
   e. Disposal of materials in appropriate facilities for treatment, disposal, or recycling.

Various types of decommissioning equipment will be used to dismantle each type of structure or equipment. Fencing, solar panels and related electrical components, and other installed structures for the Project will be decommissioned and recycled or disposed of in accordance with the manufacturer's recommendations and then-current industry standards and in compliance with then-current Federal, State and local laws and regulations.

2. The Decommissioning Plan includes provisions for removal of all the following equipment:
   a. <u>Solar Panels and Related Equipment</u>: The solar panels and support piles will be removed in their entirety, and all underground conductors will be removed to a depth of three (3) feet below the surface.
   b. <u>Roads</u>: Roads that were installed for the purpose of accessing the Project will either be restored to preconstruction conditions or left in place for the private landowner, at the landowner's discretion.

# ATTACHMENT B

## AGRICULTURAL SOIL RECLAMATION PLAN

Cavalry Energy Center, LLC ("**Company**") shall cause the construction, design, and operation of the commercial solar energy system project (the "**Project**") will not significantly reduce the quality or amount of agricultural soils on the Project site. Fallow ground allowed to rejuvenate and rebuild nutrient base may improve soil quality over the Project's life.

**Construction Phase:**

Soil disturbance will include the following activities:

1. Limited tree removal with associated stumping and grubbing;
2. Construction of the access drives;
3. Construction of the inverter pads and transformer vaults;
4. Trenching for underground conduits;
5. Any grading as deemed necessary for installation of commercial solar energy system equipment.

In most cases, existing soil is to remain onsite and generally in place. Soil temporarily disturbed during trenching for underground conduits will be placed back into the trench, with topsoil separated and placed back at the surface. The racking posts are intended to be driven into place and will therefore not require the removal or significant disturbance of soils. If racking post holes must be dug, soil will be placed back into the hole with topsoil separated and placed back at the surface.

**Operational/Maintenance Phase:**

Over the life of the facility the existing ground cover on site will be maintained as outlined in the Vegetative Management Plan prepared by Company.

**Decommissioning Phase:**

Upon the final cessation of the Project's operations, Company shall decommission the site in accordance with the Decommissioning Plan Agreement. No soils will be removed from the Project site during decommissioning, and soil disturbance will be limited to necessary equipment ingress/egress for the removal of Project facilities. Deep tillage (if determined to be needed) will be performed in areas used as access road or other activities that would compact topsoil. This is done to relieve soil compaction and promote root penetration. The soil will then be tilled with a disc, field cultivator, or chisel plow (or equivalent) to prepare a seedbed, breaking up large clods and firm the soil surface.