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IPA Policy Study
Analysis of Impact of Policies on the Illinois Transmission System

~~January~~ March ~~19~~1, 2024

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1.0 Executive Summary

The Illinois General Assembly passed Senate Bill 1699 (SB 1699) on November 9, 2023, and Governor Pritzker signed it into law on December 8, 2023, as Public Act 103-0580. Public Act 103-0580 directs the Illinois Power Agency to conduct a Policy Study to evaluate the potential impacts of proposals made during the Illinois General Assembly's Spring 2023 Legislative Session and provide policy recommendations for the General Assembly. The provisions of the Act related to the Policy Study are the same as those contained in House Bill 3445 (HB 3445) which the General Assembly passed on May 26, 2023.

These policy initiatives include a proposed offshore wind project in Lake Michigan, a high-voltage direct current transmission line, and energy storage systems ("ESS") procurements. One of the potential impacts of the proposals is the impact on grid reliability. In order to assess the impact on the reliability of the transmission system, a technical analysis has to be conducted which involves studying the impact of interconnecting the proposals into the Illinois transmission system in MISO and PJM. Entrust Solutions Group ("EN") was retained by Levitan & Associates, Inc ("LAI"), the IPA's Planning Consultant, to perform the impact analysis to determine the potential network upgrades[1] required to interconnect the proposals and the associated costs of those upgrades. The impact analysis was conducted using power flow modeling software which identifies and quantifies the metrics that can be used to assess whether or not the transmission system will continue to operate reliably after the addition of the new electric resources that would be encouraged by the policy proposals.

[1] Network upgrades are transmission system modifications to accommodate the interconnection of new or existing generation resources in order to ensure the reliability of the transmission system.

Power flow models are used extensively in the power industry to analyze the impacts on existing power systems and to identify contingencies that could be associated with new resources being added to the grid. The study models for steady-state analysis were developed using the Siemens PTI PSS®E power flow software (Version 34). The PJM Generator Deliverability analysis was conducted in PowerGEM TARA software version 2302a using the PJM Generator Deliverability 2022 Reform Tool. The MISO analysis was conducted in PowerGEM TARA software version 2301.1.

Key input data on the proposals was received from LAI, courtesy of the IPA. The IPA reached out to different stakeholders for assistance in determining the modelling assumptions for the respective proposals, including the capacities of the respective projects and the proposed points of interconnection.

- Information on the points of interconnection for the offshore wind project was obtained from a prospective developer of the project.
- The Clean Grid Alliance, the American Clean Power Association, the Solar Energy Industries Association, and the Coalition for Community Solar Access ("the Associations") recommended that the IPA use ESS projects in the PJM and MISO queues (including their capacities and points of interconnection), as indicative projects that would be built to meet the ESS targets in the policy proposal.
- The developers of the SOO Green HVDC Transmission Line provided the information on the capacity and points of interconnection for the project.

It is important to note that, while the methodologies used for the studies contained in this report are consistent with the methodologies used in MISO and PJM, the studies do not constitute full blown interconnection studies but are high-level feasibility studies which only include a thermal analysis. Thermal analysis examines the amount of power flowing on lines and through equipment when the system is in a steady state. The network upgrades required to alleviate thermal overloads are typically the highest cost upgrades seen in the study. No voltage analysis, transient stability analysis or short-circuit analysis was conducted in these studies. These analyses were not included in the studies because network upgrades are rarely seen to come out of these analyses. Additionally, the network upgrades that could potentially come from voltage, stability, and short circuit analysis would be smaller scale and would not have a substantial impact on the total network upgrade costs. The costs for network upgrades contained in this report should therefore not be compared to the final costs in a generation interconnection agreement or even to the costs in a system impact study as those costs are from higher level studies and more refined. The costs provided in this report are meant to provide a preliminary guide of the costs associated with the transmission grid impacts of the policy proposals. These costs will most certainly change as the policy proposals move forward in the interconnection process through to a formal interconnection request to PJM or MISO and to ~~the completion~~the completion of the interconnection process.

Three analyses were performed, and the results of the analyses show that all three policy proposals will require network upgrades to the transmission system for them to be able to interconnect into PJM or MISO.~~ Also, there are workpapers that are supporting information for the study that is located under IPA's Policy Study section.[2]~~ Network upgrades are modifications to a transmission system that a transmission owner must address to accommodate the interconnection of a generator. Examples of some modifications are line rebuilds, circuit breaker replacements, and upgrades to existing equipment such as transformer replacements. The developers of the generator interconnection requests will be responsible for the costs of the respective network upgrades. The requirement for network upgrades is typical for most interconnections as some level of transmission investments is often needed to maintain transmission system

~~[2] The workpapers are located here: https://ipa.illinois.gov/ipa-policy-study/draft-policy-study-supporting-information.html~~

reliability. ~~Also, there are workpapers that are supporting~~The supporting information for the study ~~that~~ is located under IPA's Policy Study section.[3]

1. Analysis of Offshore Wind Project in Lake Michigan

This study determined the potential network upgrades for five different points of interconnection in the PJM area for the 200 MW[4] of offshore wind. The study results concluded that the primary point of interconnection was the most suitable for interconnection. All five points of interconnection resulted in no impact to grid resilience.

2. Analysis of ESS in MISO and PJM

This study determined the potential network upgrades for currently queued ESS interconnection requests in MISO and PJM. For the MISO requests, 89% of the requests show network upgrade cost per megawatt on par with projects that typically move forward to project construction and 8.6% of the requests show a positive impact on grid resilience. For the PJM requests, 40% of the requests show network upgrade costs on par with projects that typically move forward and 50% of the requests show a positive impact on grid resilience.

3. Analysis of the SOO Green HVDC Transmission Line

This study determined the potential network upgrades for the SOO Green HVDC Transmission Project interconnecting into PJM. The costs for the network upgrades for the SOO Green HVDC Project are comparable to the Feasibility Study results that were released by PJM. This project shows a positive impact on grid resilience.

[3] The ~~workpapers are~~supporting information is located here: https://ipa.illinois.gov/ipa-policy-study/draft-policy-study-supporting-information.html
[4] The 200 MW capacity was determined based on information in the policy proposal.

2.0 Introduction

2.1 Overview of Generation Interconnection Process

The generation interconnection process studies the impact of the addition of capacity and energy sources into the transmission system. New interconnection requests are studied according to the process defined by the respective Regional Transmission Organization ("RTO") that oversees the requested point of interconnection. These studies identify any constraints caused by the new interconnecting project to the transmission system. The RTO determines mitigation and the network upgrades required to be in place before the interconnection request can go into service. New interconnection requests are allocated costs for these upgrades based on their impact on the transmission system. A successful interconnection application will result in an interconnection agreement that allows a connection to the transmission system.

Two different RTOs are located in the state of Illinois --- PJM and MISO as shown in Figure 2-1.

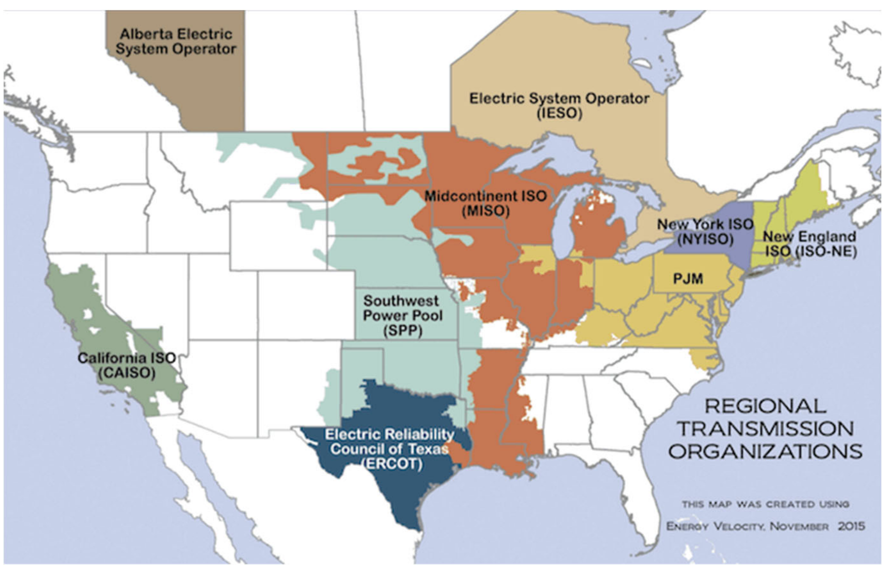

Figure 2-1: USA & Canada RTO Map

The interconnection process takes an average of three to five years to complete, although the duration can vary depending on the RTO. Generation interconnection typically includes three studies: the feasibility study, the system impact and facilities study. These studies incorporate multiple interconnection requests in a cluster[5] study approach. The RTO performing the study reviews constraints identified by the study and assigns specific network upgrades as a mitigation for the constraints. These network upgrades are allocated to the requesting generators[6] that caused the constraint. After completion of each study, the interconnection customer makes the determination to advance their project to the next phase based on the information and costs provided or withdraw the project from the cluster cycle. Once the decisions have been made, a restudy may be performed as it could change the impact and the network upgrades required for other queued generators. Assigned network upgrades and facility costs are subject to change at any time until the project executes a generation interconnection agreement.

Throughout the interconnection process, several factors can cause the expected network upgrades and associated costs for a project to fluctuate, sometimes significantly. Earlier queued projects could withdraw their interconnection request, existing generators may announce plans to retire, or baseline system transmission needs could be developed through the RTO's Regional Transmission Expansion Plan. For example, in PJM, in addition to the system changes, as a request passes through each phase of the study process, the PJM and Transmission Owners may develop and refine the scopes of the network upgrades to get a clearer picture of what a network upgrade will cost. Depending

[5] Cluster generally refers to the study of a group of interconnection requests together as opposed to studying them individually.

[6] The term generators generally refers to the studied injections which include fossil fuel generation, renewable generation, energy storage projects, and merchant transmission facilities.

on the size and impact of a project, the scope of the network upgrades and costs can vary widely. For example, in PJM, the total cost of network upgrades identified in the Feasibility Study of queue position AF1-200[7] was $715,116,062[8]. In the following study phase --- the System Impact Study --- the total cost of identified network upgrades were $232,966,340, of which AF1-200 bore the cost responsibility for $163,399,789[9]. These costs were developed in the former PJM Generator Queue Study Process. PJM has recently begun the transition to its new Study Process where AF1-200 will be re-studied. There are many moving pieces on the transmission system that could alter the results and anticipated costs of the interconnection process as it is taking place, and the total network upgrade costs will not be final and locked in until a project signs a Generation Interconnection Agreement ("GIA"). The uncertainty associated with the cost of network upgrades therefore presents considerable challenges for project developers.

It is important to note that, while the methodologies used for the studies for the proposals contained in this report are consistent with the methodologies used in MISO and PJM, the studies do not constitute full blown interconnection studies but high-level feasibility studies which only include a thermal analysis. No voltage analysis, stability analysis, short-circuit analysis, transfer limit analysis, or transient analysis were conducted in these studies. The costs for network upgrades contained in this report should therefore not be compared to the final costs in a GIA or even to the costs in a system impact study as those costs are from higher level studies and more refined. The costs provided in this report are meant to provide a preliminary guide to a prospective developer --- these costs will most certainly change as a developer makes a formal interconnection request to PJM or MISO and undergoes the complete interconnection process.

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[7] AF1-200 is the queue position of the SOO Green project in the previous PJM interconnection process.

[8] AF1-200 (pjm.com)

[9] af1200_imp.pdf (pjm.com)

2.2 PJM Interconnection Process

PJM coordinates the movement of transmission level electricity across all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. PJM operates according to its open access transmission tariff ("OATT"), which is approved by the Federal Energy Regulatory Commission ("FERC"). The PJM staff facilitates both the day-to-day operation, the energy market, and the planning of the power grid in this RTO.

PJM has recently made changes to their process for generation interconnection. Moving forward, all generator requests will go through a Cycle[10] consisting of three system impact study phases known as Phase I, Phase II, and Phase III. In each Cycle, PJM will study a group of generators and determine their impacts on the transmission system. Each Phase has a corresponding Decision Point[11] where the customer will decide to remain in the study cycle and meet the requirements for the next study Phase or withdraw the interconnection request. After being fully studied, requests that wish to go into service will sign a GIA. The generators studied during this process consist of fossil fuel generation, renewable generation, energy storage projects, and merchant transmission facilities.

When a new generator applies to interconnect to PJM's system, it chooses to be a Capacity Resource or an Energy Resource. If it chooses to be a Capacity Resource, it will be studied as such and will be granted Capacity Interconnection Rights ("CIRs"). Energy Resource status allows the generator to participate in the PJM energy market pursuant to the PJM Operating Agreement. Capacity Resource status allows the generator to provide capacity and therefore participate in the PJM capacity auctions. Capacity Resource status is based on providing sufficient transmission capability to ensure deliverability of generator output to the aggregate PJM load. Specific tests

[10] Cycle generally refers to the time a project submits its application for interconnection to the time a project negotiates the final interconnection agreement.

[11] Capitalized terms in this section are defined in the PJM OATT.

performed during the Generation Interconnection Feasibility Study and later System Impact Study will identify the specific network upgrades required to satisfy the criteria for deliverability.

2.3 MISO Interconnection Process

MISO coordinates the movement of transmission level electricity across all or part of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. MISO operates according to its OATT, which is approved by FERC. The MISO staff facilitates the day-to-day operation, the energy market, and the planning of the power grid in this region.

MISO facilitates the generation interconnection process across its RTO. All interconnection requests must be submitted to MISO during an "open window" period. All requests submitted are studied as a cluster. Clusters are interconnection requests grouped together by location and request date to study the combined impact on different areas of the MISO transmission system. MISO follows a three-phase study process, known as the Definitive Planning Phase ("DPP")[12] study, where MISO studies the generators, releases the results, then allows renewable project developers to determine if they would like to remain in the study cluster, or withdraw from the study. The interconnection process ends with the signing of a GIA that is filed with FERC. The generators studied during this process consist of fossil fuel generation, renewable generation, and energy storage projects. MISO has a separate study process for merchant transmission facilities.

There are two service types that an interconnection customer can choose from when requesting generation interconnection into MISO: Energy Resource Interconnection Service ("ERIS"), and Network Resource Interconnection Service ("NRIS"). ERIS is the

[12]Capitalized terms in this section are defined in the MISO OATT.

base service type that is granted to all interconnection customers and allows for the injection of energy into the system. NRIS allows for the injection of capacity into the system. To determine applicability for NRIS, MISO studies the requests in a Deliverability Study as part of the DPP process. This study calls for a stricter dispatch of generation, which can cause additional constraints not seen in an ERIS study. Most interconnection requests in MISO select NRIS service, however the deliverability study is optional and if costs for network upgrades end up being too high, the interconnection request can proceed with ERIS only service.

3.0 Task 1: Great Lakes Offshore Wind

3.1 Overview

EN studied five potential points of interconnection in PJM for the 200 MW offshore wind project in Lake Michigan, as shown in Table 3-1 and Figure 3-1. The Stateline 138 kV substation is the primary point of interconnection and therefore the preferred point of interconnection. The other four are the secondary points of interconnection.

Table 3-1: Offshore Wind POIs

Facility Name	kV	Capacity (MW)
Stateline Substation	138	200
Calumet Substation	138	200
North Harbor Substation	138	200
Stateline Substation	345	200
Calumet Substation	345	200

Figure 3-1: Offshore Wind Project Points of Interconnection

3.2 Model Development and Study Methodology

The 200 MW offshore wind project in Lake Michigan was analyzed at five different points of interconnection ("POIs"), one primary POI and four secondary POIs, using the latest released PJM AG1 generator interconnection cluster cycle system impact study models. For new project requests to be added to PJM or MISO systems, they must go through an assigned cluster cycle. These cluster cycles consist of typically three phases, where the interconnection customer receives analysis of their interconnection request's impact on the transmission system, and three decision points, when the interconnection customer decides to move forward with the interconnection request or withdraw the interconnection request. A case model is a model of the transmission system with all the interconnection requests of a cluster cycle which is created or updated after each decision point.

The AG1 system impact study cases do not contain any PJM queue projects after cluster cycle AG1 and are based on the Regional Transmission Expansion Plan ("RTEP") base cases released in 2019. The AG1 cases were the most recent Queue models that the

PJM Interconnection Analysis Department created and uploaded to the PJM website. These cases are created by adding each Interconnection Customer's project to the entire PJM system through a cycle which follows an alphabetical and numerical naming system. For example, one of the earliest cycles is AA1 with AA2 and AB1 cycles following. The AG1 name of the model is an indication of all the active queue/cycle projects within the model; thus, the model will contain the earliest cycle and all its projects up to the AG1 cycle's projects. The PJM RTEP base cases are created by PJM's Transmission Planning and the RTEP functions to address local, near-term needs through projects that typically go in service within 3-5 years of approval while longer-term, regional needs of the system are managed through PJM's Transmission Planning. Additional constraints may appear, or existing constraints may disappear with changes to the model over time. The AG1 system impact study cases do not contain any network upgrades that the AG1 cluster cycle requires to go into service. The offshore wind project was added to the models and studied individually. The AG1 system impact study cases do not contain any PJM queue projects after cluster cycle AG1 and do not contain RTEP projects after 2019.

The offshore wind project was studied as a capacity resource. This was done to observe all possible violations to which the project contributes. The PJM Generator Deliverability ("GD") Tool was used to carry out the analysis. The models and input files were updated to reflect the new PJM reform procedures and were implemented using the GD Tool. An identified violation, which is a transmission line or transformer with a thermal loading above its current rated capacity, is caused by the new interconnecting project to the transmission system. This is determined by the project's injection amount and electrical proximity to the overloaded facility. The RTO and Transmission Owners determine the network upgrades required to be in place before the interconnection request can go into service.

3.3 Study Results

The results of the analysis show that the Stateline 138 kV substation, the primary point of interconnection, is the most suitable point of interconnection for the offshore wind project, seeing just ten violations. Calumet 138 kV substation, and North Harbor 138 kV substation are the next suitable points of interconnection, with 11 constraints seen for each. Stateline 345 kV substation and Calumet 345 kV substation are the least appealing points of interconnection, with thirteen constraints seen for each.

The cost estimates for the network upgrades which are required for the mitigation of the violations are shown in Table 3-2. The cost of the network upgrades depends on factors such as the voltage level, the line length, and the severity of the observed overload (for example a 40% overload is considered more severe than say a 10% overload). Thus, the cost estimates are estimated using the A/C transmission in voltage classes ranging from 69 kV to 765 kV, and HVDC transmission in voltage classes from ±250 kV to ±640 kV. The degree of accuracy of the cost estimates, which are high level as explained before, is within ± 50%. Cost estimates that come directly from MISO or PJM typically reflect a ± 20% accuracy for network upgrades that can be completed within 18 months. Upgrades that require a longer lead-time are provided by MISO/PJM as good faith estimates. Generator interconnection requests that have not reached the first stage of study at the ISO level will require network upgrades with a lead-time of greater than 18 months. The cost estimates provided in this document are based on publicly released information directly from MISO, however costs for the same upgrade can change over time based on costs of labor and materials. Details on the cost estimate assumptions can be found in Appendix B.

These costs only reflect network upgrade costs, and do not include the costs for the physical connection of the project (facilities costs)[13]. Some constraints may be mitigated by other planned network upgrades outside of the Interconnection Process. The models used for generator interconnection studies may not include some planned projects that were assigned after the study models were created, so the constraint is still seen but the project would not receive cost allocation. Under the new PJM rules[14], the offshore wind project would be considered in Cycle #1 if the project was to move forward in the PJM interconnection queue, and therefore projects in Transition Cycle #1 (AE1, AE2, AF1, AF2, & AG1), Transition Cycle #2 (AG2 & AH1), and Cycle #1's AH2 may also contribute to the violations and be allocated some of the costs for the required network upgrades. Based on the current status of Transition Cycle #1, Transition Cycle #2, and Cycle #1 it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. For this reason, the study was performed conservatively and the project had 100% of the network upgrades cost allocated to it. Since this is only the Feasibility Study it is too early to accurately determine the project's cost allocation as that allocation is normally conducted at the System Impact Study phase. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer. Most network upgrades assigned to the offshore wind project will be allocated to other generation interconnection projects, resulting in a reduction of the costs allocated to the offshore wind project. The offshore wind project's costs would go down considerably since it~~'~~s individual impact on the violations would most likely be smaller because other projects ahead in the PJM queue would share costs for the network upgrades associated with the violations reported. For example in the EN study, the Stateline 138 kV Offshore Wind POI has 10 constraints that currently total about

[13] As noted before the EN study is a high level feasibility study and not a full blown interconnection study which includes a facilities study.

[14] See Docket No. ER22-2110-000, Order Accepting Tariff Revisions Subject to Condition dated November 29, 2022.

$331,200,000 assuming the entirety of the cost of the constraints, however, when it enters the PJM queue in Cycle #1 and goes through each study phase, its cost estimate of $331,200,000 would most likely decrease as PJM's Interconnection Process team determines which prior projects in cycles AE1, AE2, AF1, AF2, AG1, AG2, AH1, or AH2 also contribute to those 10 constraints. If prior projects do contribute to a constraint, they will then take on the cost of the constraint, and it is possible that the constraint would be fixed even before the offshore wind project enters the PJM queue.

Table 3-2: Offshore Wind POI Cost Comparison

POI	Number of Constraints	Cost ($MM)	$/MW
Stateline 138 kV	10	331.2	$1,656,000
Calumet 138 kV	11	369.6	$1,848,000
North Harbor 138 kV	11	369.6	$1,848,000
Stateline 345 kV	13	450.5	$2,252,500
Calumet 345 kV	13	390.9	$1,954,500

3.4 Grid Resilience Results

Grid resilience refers to the ability of the electric grid to avoid or withstand extreme events[15] without being operationally compromised or to adapt to and compensate for the resultant strains. Extreme events in this study are identified as multiple contingency P5 and P7 events.

- P5 events consist of delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed for generators, transmission circuits, transformers, shunt devices, or bus sections.

[15] Extreme events typically occur during severe weather events, or unusual grid behavior events.

- P7 events consist of the loss of any two adjacent circuits on common structures or the loss of a bipolar DC line.

Over 1,800 extreme events were analyzed for the PJM analysis. No extreme events were identified as a violation in this offshore wind study. This means that the wind project has not caused any additional elements to exceed their rating. All five points of interconnection have shown no impact, neither harming nor helping, on grid resilience.

4.0 Task 2: Energy Storage Systems[16]

4.1 Overview

As noted previously, EN received the information on the capacities and points of interconnection of the ESS from LAI, courtesy of the IPA. Based on the recommendations of stakeholders the list of ESS capacities and points of interconnection for MISO were developed as follows:

- The allocation was guided by SB 1587
  - SB 1587 recommends a procurement by the IPA of ESS of at least 5,000 MW by 2028, and at least 7,500 MW by 2030.
  - The ESS allocation for the years 2028 and 2030 was based on the following percentages.
    - 70% in MISO
    - 10% in Chicago, Illinois (PJM)
    - 20% in PJM (Outside Chicago but in IL, *i.e.,* in ComEd)
  - The resultant allocation for 2030 was as follows.
    - 5,250 MW - MISO
    - 750 MW - Chicago, IL (PJM)
    - 1,500 MW - PJM (Outside Chicago but in IL, *i.e.,* in ComEd)
- Based on the MISO allocation of 5,250 MW by 2030, a list of 35 ESS points of interconnection was determined from existing queue positions, with some project capacities adjusted to match the required allocation.
- Based on the PJM allocation of 750 MW for Chicago, IL, and 1,500 MW for the rest of PJM (*i.e.*, outside Chicago but in IL – ComEd) a list of 10 ESS points of interconnection was determined from existing queue positions, with some project capacities adjusted to match the required allocation.

[16] Only utility-scale ESS are modelled. There was no modelling of behind the meter ESS, or ESS that is connected to community solar projects, which are connected to the distribution system. Studying the entire distribution system was not feasible in this study.

- Taking into account project development time, and delays in implementing the legislation, it was assumed that the 7,500 MW would be in-service by 2035.

EN performed an injection analysis of the 45 existing ESS queue positions in PJM and MISO. This study determines the potential network upgrades for the ESS queue positions.

MISO BESS Requests

	Number of Projects	Capacity (MW)	Queue
	2	100	DPP-2020-Cycle
	9	775	DPP-2021-Cycle
	24	4375	DPP-2022-Cycle
Total	**35**	**5250**	

PJM BESS Requests

	Number of Projects	Capacity (MW)	Queue
Total	**10**	**2250**	

Figure 4-1: ESS Request Queue Cycles

For MISO, projects are studied by the year that they entered their interconnection service request. There are two projects in the DPP-2020 Central cluster, nine projects in the DPP-2021 Central cluster, and twenty-four in the DPP-2022 Central cluster. For PJM, based on the new interconnection process, there are two projects in Transition Cycle #1 and two projects in Transition Cycle #2[17]. The remaining six projects will be in Cycle #1. The locations modeled were meant to be illustrative in nature as it is not possible to know what actual projects will be selected through a future competitive procurement process. Therefore, the results listed in this section are illustrative examples of costs and if different locations are ultimately selected, the results could be very different.

[17] During PJM's Queue Reform, PJM has updated its process from a "first come, first served" approach to a "first ready, first served" approach. PJM opened a window for existing interconnection requests to provide all information for study. This open window was used to form the Transition Cycle #1 and Transition Cycle #2. Transition Cycle #1 consists of re-prioritized projects AE1, AE2, AF1, AF2, & AG1 based on the PJM's new interconnection procedures and Transition Cycle #2 consists of AG2 & AH1 projects with its application deadline starting after Transition Cycle #1 is underway. Cycle #1 is the new PJM cycle that will consist of AH2 & beyond projects with its application deadline in mid-2025.

4.2 MISO Model Development and Study Methodology

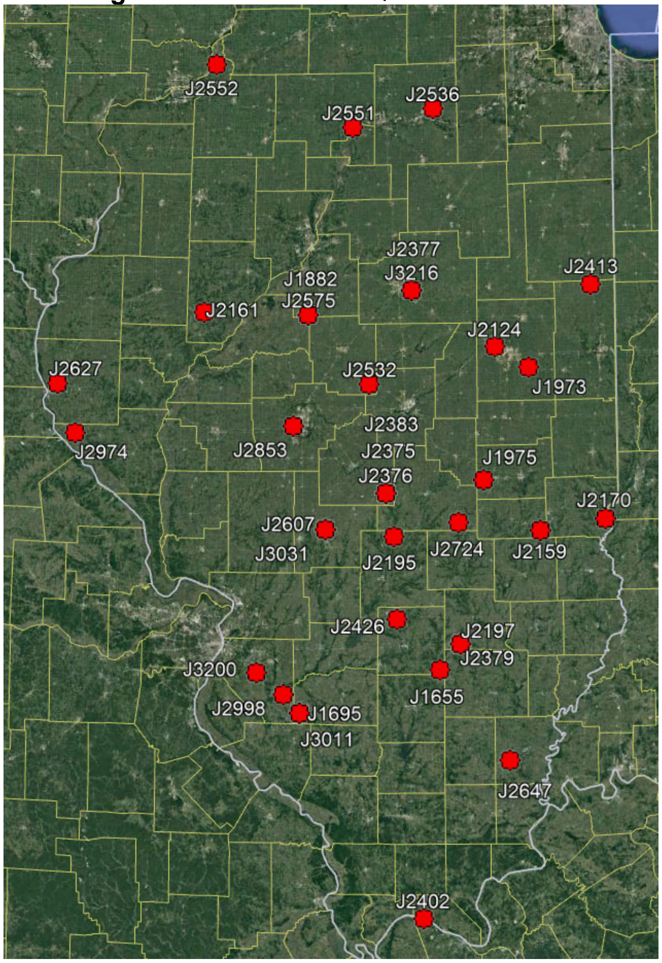
The latest relevant MISO Generation Interconnection cases were utilized for the NRIS, ERIS Peak, and ERIS Shoulder cases[18]. The models utilized for the study are DPP-2021 and DPP-2022. For this analysis, the studied MISO projects were already modelled in the cases, but some generator capacities needed to be updated to reflect the information received with the requested POIs.

Table 4-1: MISO ESS Queue Positions

Queue Position	Queue Cycle	Capacity (MW)
J1655	DPP-2020	50
J1695	DPP-2020	50
J1882	DPP-2021	45
J1973	DPP-2021	40
J1975	DPP-2021	40
J2124	DPP-2021	100
J2159	DPP-2021	100
J2161	DPP-2021	100
J2170	DPP-2021	150
J2195	DPP-2021	100
J2197	DPP-2021	100
J2375	DPP-2022	100
J2376	DPP-2022	100
J2377	DPP-2022	300
J2379	DPP-2022	200
J2383	DPP-2022	100
J2402	DPP-2022	200
J2413	DPP-2022	150
J2426	DPP-2022	200
J2532	DPP-2022	200
J2536	DPP-2022	200
J2551	DPP-2022	110
J2552	DPP-2022	130
J2575	DPP-2022	200
J2607	DPP-2022	200
J2627	DPP-2022	150
J2647	DPP-2022	300
J2724	DPP-2022	300
J2853	DPP-2022	100
J2974	DPP-2022	50
J2998	DPP-2022	200
J3011	DPP-2022	100
J3031	DPP-2022	200
J3200	DPP-2022	250
J3216	DPP-2022	300

[18] The case models utilized were created to reflect each seasonal load profile such as Summer Peak and in the cases each interconnection project is dispatched at specific levels provided by MISO's Transmission Planning.

Figure 4-2: MISO ESS Queue Positions



4.3 MISO Results

Requests were studied based on the selected service type listed in the MISO public queue. For DPP-2020 requests, costs come from the latest released DPP-2020 Phase 1 study report. For DPP-2021 and DPP-2022, requests were studied using the latest released study models for each cluster cycle. Table 4-2 shows costs for the required network upgrades including the unit costs. The degree of accuracy of the costs is ± 50%.

Table 4-2: MISO ESS Network Upgrade Costs and Unit Costs

Queue Position	Queue Cycle	Project Size (MW)	Total Network Upgrade Cost ($)	$/MW
J1655	DPP-2020	50	$ 12,091,984.29	$ 241,839.69
J1695	DPP-2020	50	$ 5,975,035.02	$ 119,500.70
J1882	DPP-2021	45	$ 6,310,000.00	$ 140,222.22
J1973	DPP-2021	40	$ 1,777,500.00	$ 44,437.50
J1975	DPP-2021	40	$ 1,721,000.00	$ 43,025.00
J2124	DPP-2021	100	$ 4,016,900.00	$ 40,169.00
J2159	DPP-2021	50	$ 7,190,000.00	$143,800.00
J2161	DPP-2021	50	$ 922,857.85	$ 18,457.16
J2170	DPP-2021	150	$ 122,710,000.00	$ 818,066.67
J2195	DPP-2021	100	$ 8,337,700.00	$ 83,377.00
J2197	DPP-2021	100	$ 8,436,600.00	$ 84,366.00
J2375	DPP-2022	100	-	-
J2376	DPP-2022	60	$ 29,820,000.00	$ 497,000.00
J2377	DPP-2022	300	$ 6,970,000.00	$ 23,233.33
J2379	DPP-2022	200	$ 12,311,000.00	$ 61,555.00
J2383	DPP-2022	100	$ 2,350,000.00	$ 23,500.00
J2402	DPP-2022	200	$ 1,290,000.00	$ 6,450.00
J2413	DPP-2022	150	$ 13,091,560.00	$ 87,277.07
J2426	DPP-2022	200	$ 39,830,000.00	$ 199,150.00
J2532	DPP-2022	200	$ 18,790,000.00	$ 93,950.00
J2536	DPP-2022	200	$ 4,360,000.00	$ 21,800.00
J2551	DPP-2022	110	$ 13,270,000.00	$ 120,636.36
J2552	DPP-2022	80	$ 8,180,000.00	$ 102,250.00
J2575	DPP-2022	198	$ 23,350,000.00	$ 117,929.29
J2607	DPP-2022	200	$ 7,480,000.00	$ 37,400.00
J2627	DPP-2022	150	$ 14,880,000.00	$ 99,200.00
J2647	DPP-2022	300	$ 6,100,000.00	$ 20,333.33
J2724	DPP-2022	300	$ 11,290,000.00	$ 37,633.33
J2853	DPP-2022	100	$ 6,570,300.00	$ 65,703.00
J2974	DPP-2022	50	$ 29,256,500.00	$ 585,130.00
J2998	DPP-2022	200	$ 34,449,313.92	$ 172,246.57
J3011	DPP-2022	100	$ 17,587,400.00	$ 175,874.00
J3031	DPP-2022	200	$ 13,210,000.00	$ 66,050.00
J3200	DPP-2022	250	$ 18,782,500.00	$ 75,130.00
J3216	DPP-2022	300	$ 6,970,000.00	$ 23,233.33

Project developers strive to have the lowest network upgrade costs possible. The range for network upgrade costs can vary but most interconnection projects that move forward in the interconnection process have network upgrade costs that are equal to or less than $200,000 per MW. There are analyses that were completed by MISO and PJM that examined the network upgrade cost per MW and these analyses were utilized to create a general rule of thumb (a project's network upgrade costs are equal to or less than $200,000 per MW) for interconnection customers to use to determine if the project request should move forward in the interconnection process or not. The table above, Table 4-2, has the projects' "$/MW" highlighted in green to indicate that it may move forward based on this rule of thumb. One analysis example that was done by MISO reviewed network upgrade costs per MW in the MISO queue between 2017 and 2020. The average cost per MW for a Phase 1 request was $232,051 across all years.[19] In PJM, 95% of the completed projects between 2020 and 2022 have network upgrade costs under $200,000 per MW.[20] Project developers can lower their network upgrade costs by dropping the NRIS service or by reducing the project size. As shown in Table 4-2, 89% of the studied queue positions show network upgrade costs that are on par with projects that typically move forward in the interconnection process and eventually to project construction. These costs do not include the costs for the physical connection of the projects (facilities costs). Some identified constraints may be mitigated by Network Upgrades outside of the Interconnection Process. In such cases, the interconnection request would not be allocated any network upgrade costs. The MISO projects were studied in their appropriate cluster cycle, so costs for network upgrades were shared appropriately with other equally queued requests. Also, if prior cluster cycle projects do contribute to a constraint, they will then take on the cost of the constraint which will lower the MISO projects' costs.

[19] https://cdn.misoenergy.org/20230719%20PAC%20Item%2006%20Charles%20River%20Associates%20Queue%20Reform%20Report629633.pdf

[20] https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf

4.4 MISO Grid Resilience Results

Over 3,000 extreme events were analyzed for the MISO analysis. For the MISO ESS projects, three projects saw constraints from extreme events. These extreme event violations would be mitigated during the study process via upgrade projects driven by the generation interconnection. Study results can be found in Appendix G.

J2170, J2552, and J2607 would have a positive impact on grid resilience since the violations flagged would be mitigated during the study process. This means that 8.6% of the provided requests in MISO show a positive impact on grid resilience. All other projects have no impact on grid resilience.

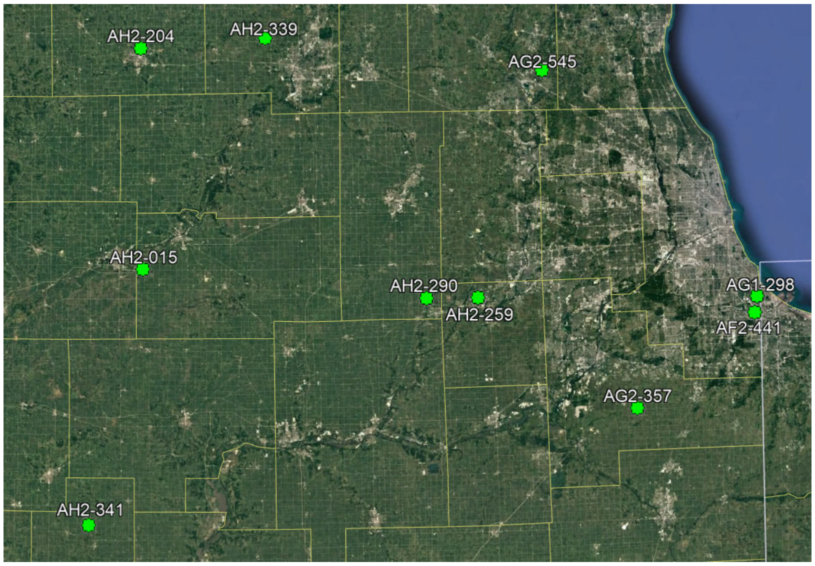
4.5 PJM Model Development and Study Methodology

The PJM ESS projects were studied using the latest released PJM AG1 system impact models. The latest AG1 system impact study cases were released in 2019 and do not contain any network upgrades that the AG1 cluster cycle requires to go into service. The ESS projects not already in the model were added and all ESS projects were studied together as a cluster.

Table 4-4: PJM ESS Queue Positions

Queue Position	Capacity (MW)
AG1-298	500
AG2-357	250
AG2-545	400
AF2-441	250
AH2-015	110
AH2-204	170
AH2-259	150
AH2-290	60
AH2-339	110
AH2-341	250

Figure 4-3: PJM ESS Queue Positions



The PJM ESS projects were studied at their maximum output capacity values that were provided. The PJM Generator Deliverability ("GD") Tool was used to carry out the analysis. The models and input files were updated to reflect the new PJM interconnection procedures and were implemented using the GD Tool. To identify potential violations the transmission facilities were analyzed to determine if there were any overloads.

4.6 PJM Results

Cost estimates for the network upgrades required for mitigation of the identified violations were developed. The cost of the network upgrades depends on factors such as voltage level, line length, and the severity of the observed overloads. The degree of accuracy of the estimates is ± 50%. Details on the cost estimate assumptions can be found in Appendix B. Some constraints may be mitigated by network upgrades outside of the interconnection process. In such cases, the interconnection request would not be allocated any costs to mitigate the constraint. These costs do not include the costs for the physical connection of the project (facilities costs). The models used for generator interconnection studies may not include some planned projects that were assigned after the study models were created, so the constraint is still seen but the project would not receive cost allocation. Under the new PJM interconnection procedures, the PJM ESS projects would be considered in Transition Cycle #1 (AE1, AE2, AF1, AF2, & AG1), Transition Cycle #2 (AG2 & AH1), and Cycle #1 if the projects were to move forward in the PJM interconnection queue. Therefore, projects in Transition Cycle #1(AE1, AE2, AF1, AF2, & AG1), Transition Cycle #2 (AG2 & AH1), and Cycle #1's AH2 may also contribute to the violations. Based on the current status of Transition Cycle #1, Transition Cycle #2, and Cycle #1 it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer. The PJM ESS projects' costs would most likely go down considerably since the projects' individual impact on the violations would most likely be smaller because other projects ahead in the PJM queue would share costs for the network upgrades associated with the violations reported. To reiterate, the prior queued projects in AG2 & AH1 cycles were not part of the EN study since they are still going through the new PJM interconnection process and so the six AH2 queued projects' costs would decrease since there is a high probability the queued projects in the AG2 and AH1 cycles may also be allocated some of the costs of the constraints visible to those six AH2 queued projects.

Table 4-5: PJM ESS Cost of Network Upgrades and Unit Costs

	Project Size (MW)	Network Upgrade Cost ($MM)	$/MW
AG1-298	500	67.47	134,940
AG2-357	250	13.77	55,080
AG2-545	400	19.65	49,125
AF2-441	250	50.08	200,320
AH2-015	110	157.52	1,432,000
AH2-204	170	113.24	666,118
AH2-259	150	119.25	795,000
AH2-290	60	19.29	321,500
AH2-339	110	425.05	3,864,091
AH2-341	250	220.11	880,440

Developers and interconnection customers strive to have the lowest network upgrade cost possible. Ranges for the costs of network upgrades can vary but most projects that move forward in the interconnection process and eventually to construction have network upgrade costs are equal to or less than $200,000 per MW. As shown in Table 4-5 above, it has the projects' "$/MW" highlighted in green to indicate that it may move forward based on this rule of thumb and so 40% of the PJM queue positions show network upgrade costs that are on par with projects that typically move forward in the interconnection process and eventually to project construction. This percentage could be lower than what is seen for the MISO projects for multiple reasons including that the sample size may not be large enough or that where these projects interconnect to the ComEd transmission system is more congested and requires more substantial upgrades. The requests above were studied as an independent cluster, while MISO projects were studied with respect to queue priority, which means that the costs for network upgrades were shared with far fewer projects. When studied by PJM, it is likely that the network upgrades will be shared across other generation requests in the PJM queue. Project developers can potentially lower their network upgrade costs by reducing the project size. It is important to note that costs allocated to projects in the PJM system are subject to change as generation requests make their way through the study process.

4.7 PJM Grid Resilience Results

Over 1,800 extreme events were studied for the PJM analysis. Five of the PJM ESS queue positions experienced violations during extreme events. These extreme event violations would be mitigated during the study process. Detailed results can be found in Appendix G.

AF2-441, AH2-204, AH2-259, AH2-290, and AH2-339 queue positions (50% of the studied requests) have a positive impact on grid resilience since the violations flagged would be mitigated during the study process. All other projects have no impact on grid resilience.

5.0 Task 3: SOO Green HVDC Transmission Line

5.1 Overview

EN performed an injection analysis of the 2,035 MW[21] SOO Green HVDC Transmission Line. Contingencies studied included P0, P1, P2, P4, P5 & P7 events. This study determined the potential network upgrades for the project's interconnection. Preliminary, exploratory costs were provided based on the constraints seen in the study. As previously noted, all the information on the project including capacity and point of interconnection were provided by the project's developer.

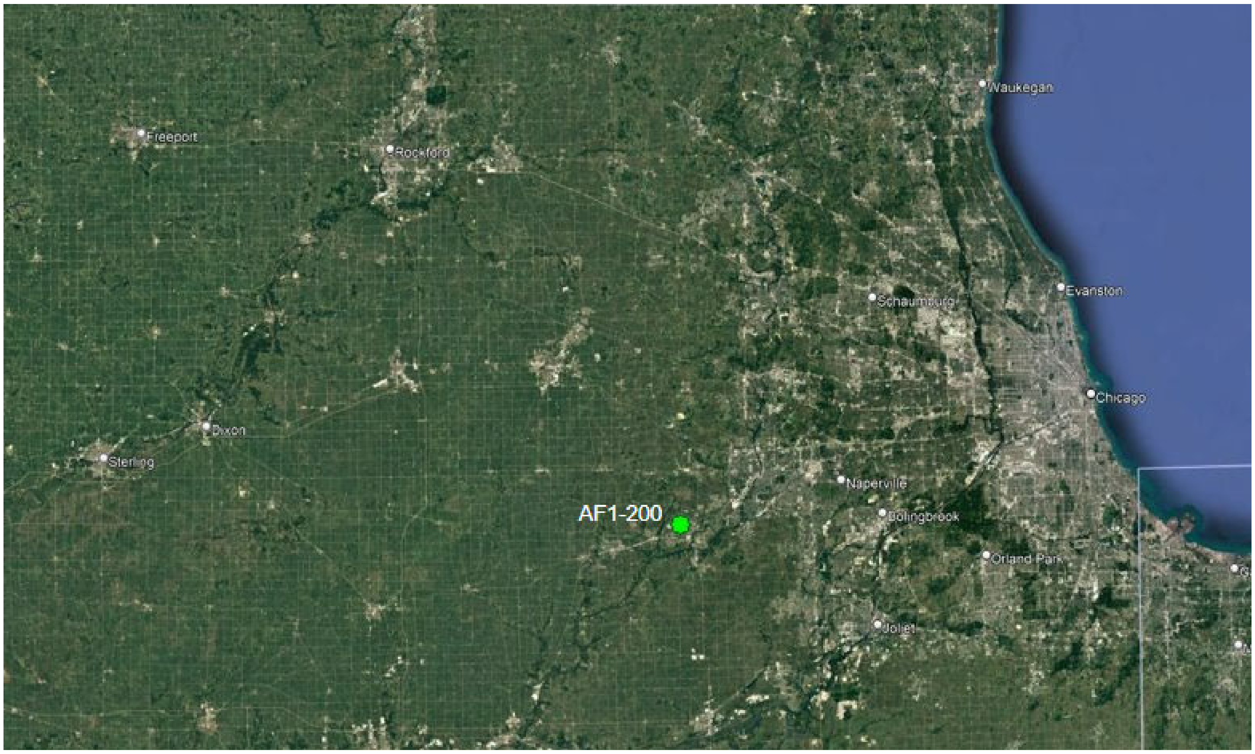


Figure 5-1: SOO Green Location

[21] The line's capacity is 2,100 MW. 2,035 MW takes into account about 65 MW of line losses.

5.2 Model Development and Study Methodology

The HVDC project was studied using the latest released PJM AG1 system impact study models. The released AG1 system impact study cases were released in 2019 and do not contain any network upgrades that the AG1 cluster cycle requires to go into service.

The AG1 system impact study cases do not contain any PJM Queue projects after cluster cycle AG1 and do not contain RTEP projects after 2019. Mitigation for constraints observed in the study can possibly be done using network upgrades from other PJM planning studies.

The HVDC project was studied as a capacity resource. This was done to observe all possible violations to which the project contributes. The PJM GD Tool was used to carry out the analysis. The models and input files were updated to reflect the new PJM interconnection procedures and were implemented using the GD Tool. To identify potential violations the transmission facilities were analyzed to determine if there were any overloads.

5.3 Study Results

There was a total of twenty-four constraints which were identified as being impacted by the addition of the SOO Green HVDC project. Nineteen of the constraints were 345 kV transmission lines, one was a 765 kV transmission line, and four were 765/345 kV transformers.

Cost estimates for the network upgrades required for mitigation of the constraints were developed. The costs for the network upgrades depend on such factors as the voltage level, line length, and severity of observed overloads. The degree of accuracy of the cost estimates is ± 50%. Details on the cost estimate assumptions can be found in Appendix B. These do not include the costs for the physical connection of the project (facilities costs). Some constraints may be mitigated by other projects outside of the interconnection process. The PJM Transmission Expansion Advisory Committee identifies network upgrade projects to resolve baseline reliability criteria violations. These transmission system enhancements may provide mitigation for constraints seen for SOO Green. The SOO Green HVDC project would be considered in the Transition Cycle #1(AE1, AE2, AF1, AF2, & AG1) in the new PJM interconnection process. Other requests in Transition Cycle #1 may also contribute to the overloads reported, and thus share network upgrade costs with SOO Green. Since the SOO Green HVDC project is part of the Transition Cycle #1 and cycles such as Transition Cycle #1, Transition Cycle #2, and Cycle #1 are still a work in progress because of PJM's reform process, any updated cost for the network upgrades for SOO Green will only be known after the completion of the respective cycle. As the cycles go through decision points and projects either withdraw or enter the queue, the cost of the SOO Green project would become more certain.

Table 5-1: Constraints list for SOO Green HVDC Project

	# of Facilities seen with constraints
765 kV Lines	1
345 kV Lines	19
765/345 kV Transformers	4

Table 5-2: Cost of SOO Green Network Upgrades and Unit Cost

Project Size (MW)	Cost of Network Upgrades ($MM)	$/MW
2,035	801.8	394,005

Developers and interconnection customers strive to have the lowest network upgrade cost possible. The $801.8 MM cost is comparable to the $715.1 MM Feasibility Study Cost for the SOO Green project which was conducted by PJM as queue position AF1-

200 in the previous PJM interconnection process. As noted before the EN study is a high level feasibility study. The SOO Green project was studied under the previous PJM process and is currently being studied in the new PJM process as queue position AF1-200. The total cost of network upgrades identified in the Feasibility Study of queue position AF1-200 was $715,116,062[22]. In the following study phase --- the System Impact Study --- the total cost of identified network upgrades were $232,966,340, of which AF1-200 bore the cost responsibility for $163,399,789[23]. Because of the nature of the more detailed system impact study, and the cost allocation that takes place during that phase of the interconnection process, with other queue positions taking in part of the cost responsibility, SOO Green's cost dropped significantly to $163,399,789. Therefore, as SOO Green progresses in Transition Cycle #1, a cluster study, the expectation is that the project's network upgrade costs will most likely go down.

5.4 Grid Resilience Results

Over 1,800 extreme events were analyzed for the PJM analysis. One extreme event was reported as a violation in this study. The reported extreme event violation was found in the ComEd area which is in Illinois and is a P7 contingency (defined in Section 3.2 and detailed results can be found in Appendix H). The SOO Green HVDC project would have a positive impact on grid resilience since the violation flagged would be mitigated during the study process. Detailed results can be found in Appendix H.

[22] AF1-200 (pjm.com)

[23] af1200_imp.pdf (pjm.com)

Appendix A: Study Methodologies

N-1 Thermal Criteria

All facilities 100 kV and above in all PJM or MISO zones were monitored for thermal violations. These facilities shall be loaded below normal ratings for system intact conditions (all lines in-service or N-0) and loaded below long-time emergency (LTE) ratings for post-contingency (N-1) conditions.

This analysis focused on thermal analysis since the upgrades from voltage analysis are generally lower in cost, require shorter time to construct, and face fewer permitting challenges.

For contingencies, all PJM and MISO system contingencies were studied with the corresponding cases.

Study Tools

The study models for steady-state analysis were developed using the Siemens PTI PSS®E power flow software (Version 34). The PJM Generator Deliverability analysis was conducted in PowerGEM TARA software version 2302a using the PJM Generator Deliverability 2022 Reform Tool. The MISO analysis was conducted in PowerGEM TARA software version 2301.1.

Appendix B: Cost Estimate Assumptions

These cost estimates are high-level using per mile costs to reconductor lines and unit costs to purchase and install substation equipment. Cost estimates are based on the snapshot in time provided by the study models. As we see changes in the study model, costs may shift to other generator interconnection requests, or other planning processes within the RTO. Costs may increase or decrease depending on the network upgrades selected through the generator interconnection process performed by the RTO. Costs listed in this report are estimations based on publicly available information.

Line upgrades can be achieved by reconductoring/rebuilding the lines and replacing terminal equipment. Reconductoring can be achieved by replacing the existing conductors with conductors of similar weight but a higher rating without significant work on the structures (lower cost), while rebuilding requires replacing the tower structures and using heavier conductors (higher cost, usually at least 5 times of the reconductoring cost). A cutoff percentage of 135% was used to determine whether reconductoring is sufficient (loading <= 135%) or a rebuilding is necessary (loading > 135%). New transmission lines were not considered to address the identified overloads.

Line upgrades include the cost to reconductor/rebuild the line. Based on publicly available information, it is not possible to determine whether the line is terminal equipment limited (could be addressed by replacing circuit breakers, disconnect switches, wave traps, protective relays, etc.), conductor limited (could require reconductoring the entire length of the line), sag limited (could be addressed by rebuilding specific structures to increase clearance to utilize full conductor rating), or some combination of these conditions. The reconductoring costs are general purpose per mile costs and the actual cost could vary based on the amount of structure work needed to support the weight of new conductors, which may increase mechanical loading on transmission structures.

The transformer cost estimate includes the cost to install a parallel transformer and circuit breakers and associated equipment to connect the transformer to the bus at each voltage level.

The MISO Transmission Cost Estimation Guide[24] was used for the cost estimates. The cost guides are shown in Table 1.

Table 1: Per Mile Cost Basis for Line Upgrades

kV	Type	Upgrade Type	Cost Per Mile ($MM)
138	OH	Reconductor	0.37
138	OH	Rebuild	1.7
345	OH	Reconductor	0.59
345	OH	Rebuild	3.2
765	OH	Reconductor	1.09

EN estimates the transformer additions would require 30-36 months to design, procure, and construct. Line reconductoring for the shorter lines would require on the order of 24 months. The longer lines (> 10 miles) could require 30-36 months.

[24] Transmission Cost Estimation Guide for MTEP22337433.pdf (misoenergy.org)

Appendix C: Offshore Wind POI Comparison

	Stillwell - Dumont 345 kV	Green Acre - Olive 345 kV	17 Green Acre - Green Acre 345 kV	Dumont - Sorenson 765 kV	Jefferson - Clifty 345 kV	AF2-359 Tap - Olive 345 kV	University Park - AF2-359 Tap 345 kV	St. John - Green Acre 345 kV	17 St. John - St. John 345 kV	Jefferson 765/345 kV	Crete – St John 138 kV	Hayes – Beaver 345 kV	Sorenson – AF2-137 tap 765 kV	Burnham – Sheffield 345 kV	Wilton Center 765/345 kV
Stateline 138 kV	x	x	x	x	x	x	x	x	x	x					
Calumet 138 kV	x	x	x	x	x	x	x	x	x	x	x				
Stateline 345 kV	x	x	x	x	x	x	x	x	x	x	x	x	x		
Calumet 345 kV	x	x	x	x	x	x	x	x	x	x	x			x	x
North Harbor 138 kV	x	x	x	x	x	x	x	x	x	x	x				

								Stateline 138 kV							
Model	**Monitored Facility**	**Voltage (kV)**	**Rating (MVA)**	**Contingency Type**	**Contingency**	**Pre Queue Loading %**	**Post Queue Loading %**	**Dfax**	**Impact (MW)**	**Cost Allocation (%)**	**Cost Allocation ($MM)**	**Reconductor Cost ($MM)**	**Rebuild Cost ($MM)**	**Replacement Cost ($MM)**	**Reinforcement Cost ($MM)**
AG1 LL 2024 LL NonDiv NonMTX	STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	146.13	149.35	0.19638	43.2044	100.0	36.64	6.7555	36.64	-	36.64
AG1 LL 2024 LL NonDiv NonMTX	GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	116.99	122.64	0.09265	20.3832	100.0	27.8008	27.8008	150.784	-	27.8008
AG1 LL 2024 LL NonDiv NonMTX	GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	104.13	109.15	0.09265	20.3832	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 LL 2024 LL NonDiv NonMTX	DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	100.22	102.01	0.22935	50.457	100.0	7.63	7.63	7.63	-	7.63
AG1 SIS 2024 TARA NonDiv NonMTX	JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Single	AEP_P1-2_#709_546	175.93	178.24	0.10433	22.953	100.0	2.56	0.472	2.56	-	2.56
AG1 SIS 2024 TARA NonDiv NonMTX	AF2-359_TAP - OLIVE Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	174.35	177.3	0.08038	17.6834	100.0	23.456	4.3247	23.456	-	23.456
AG1 SIS 2024 TARA NonDiv NonMTX	UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	152.74	155.13	0.08038	17.6834	100.0	210.944	38.8928	210.944	-	210.944
AG1 SIS 2024 TARA NonDiv NonMTX	ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.27	130.76	0.06613	14.5484	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 SIS 2024 TARA NonDiv NonMTX	STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.27	130.75	0.06613	14.5484	100.0	4.0002	4.0002	21.696	-	4.0002

								Calumet 138 kV							
Model	Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
AG1 LL 2024 LL	STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	146.12	149.34	0.19578	43.0726	100.0	36.64	6.7555	36.64	-	36.64
AG1 LL 2024 LL	GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	116.99	122.64	0.09257	20.366	100.0	27.8008	27.8008	150.784	-	27.8008
AG1 LL 2024 LL	GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	104.13	109.15	0.09257	20.366	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 LL 2024 LL	DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	100.22	102.01	0.2294	50.4684	100.0	7.63	7.63	7.63	-	7.63
AG1 SIS 2024 TARA	JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Single	AEP_P1-2_#709_546	175.93	178.24	0.10432	22.9505	100.0	2.56	0.472	2.56	-	2.56
AG1 SIS 2024 TARA	AF2-359_TAP - OLIVE Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	174.36	177.31	0.0809	17.7971	100.0	23.456	4.3247	23.456	-	23.456
AG1 SIS 2024 TARA	CRETE_EC_BP - STJOHN Ckt #1 345 kV	345	1399	Single	AEP_P1-2_#695_1681	154.14	157.5	0.06309	9.0675	100.0	38.368	7.0741	38.368	-	38.368
AG1 SIS 2024 TARA	UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	152.75	155.14	0.0809	17.7971	100.0	210.944	38.8928	210.944	-	210.944
AG1 SIS 2024 TARA	ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.28	130.76	0.06673	14.6801	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 SIS 2024 TARA	STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.29	130.76	0.06673	14.6801	100.0	4.0002	4.0002	21.696	-	4.0002
AG1 SIS 2024 TARA	JEFRSO - JEFRSO Ckt #2 765/345 kV	765/345	3039	Single	AEP_P1-2_#709_546	108.14	110.45	0.10432	22.9505	100.0	18	-	-	18	18

								Stateline 345 kV							
Model	Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
AG1 LL 2024 LL	STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	146.22	149.48	0.2001	44.0211	100.0	36.64	6.7555	36.64	-	36.64
AG1 LL 2024 LL	GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	116.97	122.47	0.09128	20.0826	100.0	27.8008	27.8008	150.784	-	27.8008
AG1 LL 2024 LL	GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	104.11	109.00	0.09128	20.0826	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 LL 2024 LL	DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	100.23	101.94	0.22967	50.527	100.0	7.63	7.63	7.63	-	7.63
AG1 SIS 2024 TARA	JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Single	AEP_P1-2_#709_546	175.93	178.24	0.10432	22.9494	100.0	2.56	0.472	2.56	-	2.56
AG1 SIS 2024 TARA	AF2-359_TAP - OLIVE Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	174.37	177.31	0.08103	17.8266	100.0	23.456	4.3247	23.456	-	23.456
AG1 SIS 2024 TARA	CRETE_EC_BP - STJOHN Ckt #1 345 kV	345	1399	Single	AEP_P1-2_#695_1681	154.21	157.55	0.06733	14.8122	100.0	38.368	7.0741	38.368	-	38.368
AG1 SIS 2024 TARA	UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	152.76	155.14	0.08103	17.8266	100.0	210.944	38.8928	210.944	-	210.944
AG1 SIS 2024 TARA	ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.32	130.79	0.06821	15.0053	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 SIS 2024 TARA	STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.32	130.78	0.06821	15.0053	100.0	4.0002	4.0002	21.696	-	4.0002
AG1 SIS 2024 TARA	HAYES - BEAVER Ckt #1 345 kV	345	1844	Single	BEAVER -AD1-103 TAP 345 kV ckt 1	118.74	119.28	0.05894	12.9657	100.0	35.105	35.105	190.4	-	35.105
AG1 SIS 2024 TARA	SORENS - AF2-137_TAP Ckt #1 765 kV	765	4142	Single	AEP_P1-2_#709_546	116.48	117.55	0.24096	53.0103	100.0	45.78	45.78	45.78	-	45.78
AG1 SIS 2024 TARA	JEFRSO - JEFRSO Ckt #2 765/345 kV	765/345	3039	Single	AEP_P1-2_#709_546	108.14	110.45	0.10432	22.9494	100.0	18	-	-	18	18

								Calumet 345 kV							
Model	Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
AG1 LL 2024 LL	STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	145.92	149.17	0.18111	39.845	100.0	36.64	6.7555	36.64	-	36.64
AG1 LL 2024 LL	GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	116.96	122.48	0.09078	19.9715	100.0	27.8008	27.8008	150.784	-	27.8008
AG1 LL 2024 LL	GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	104.1	109.01	0.09078	19.9715	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 LL 2024 LL	WILTON_4M - WILTON Ckt #1 345/765 kV	345/765	1379	Single	COMED_P1-2_765-L11216__-S	101.22	103.18	0.09973	21.9414	100.0	18	-	-	18	18
AG1 LL 2024 LL	DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	100.24	102.03	0.23043	50.6953	100.0	7.63	7.63	7.63	-	7.63
AG1 SIS 2024 TARA	JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Single	AEP_P1-2_#709_546	175.93	178.23	0.10396	22.8721	100.0	2.56	0.472	2.56	-	2.56
AG1 SIS 2024 TARA	AF2-359_TAP - OLIVE Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	174.65	177.59	0.09336	20.5394	100.0	23.456	4.3247	23.456	-	23.456
AG1 SIS 2024 TARA	CRETE_EC_BP - STJOHN Ckt #1 345 kV	345	1399	Single	AEP_P1-2_#695_1681	154.7	158.04	0.09882	21.7399	100.0	38.368	7.0741	38.368	-	38.368
AG1 SIS 2024 TARA	UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	153.03	155.42	0.09336	20.5394	100.0	210.944	38.8928	210.944	-	210.944
AG1 SIS 2024 TARA	ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.61	131.07	0.08255	18.1611	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 SIS 2024 TARA	STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.61	131.07	0.08255	18.1611	100.0	4.0002	4.0002	21.696	-	4.0002
AG1 SIS 2024 TARA	JEFRSO - JEFRSO Ckt #2 765/345 kV	765/345	3039	Single	AEP_P1-2_#709_546	108.14	110.45	0.10396	22.8721	100.0	18	-	-	18	18
AG1 SIS 2024 TARA	BURNHAM_B - SHEFFIELD Ckt #1 345 kV	345	1441	Single	COMED_P1-2_765-L11215__-S	104.11	106.13	0.26088	57.3941	100.0	3.3158	3.3158	17.984	-	3.3158

									N Harbor 138 kV						
Model	Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
AG1 LL 2024 LL	STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	146.12	149.35	0.19591	43.1	100.0	36.64	6.7555	36.64	-	36.64
AG1 LL 2024 LL	GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	116.99	122.64	0.09259	20.3696	100.0	27.8008	27.8008	150.784	-	27.8008
AG1 LL 2024 LL	GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	104.13	109.15	0.09259	20.3696	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 LL 2024 LL	DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	100.22	102.01	0.22939	50.466	100.0	7.63	7.63	7.63	-	7.63
AG1 SIS 2024 TARA	JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Single	AEP_P1-2_#709_546	175.93	178.24	0.10432	22.951	100.0	2.56	0.472	2.56	-	2.56
AG1 SIS 2024 TARA	AF2-359_TAP - OLIVE Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	174.35	177.31	0.08079	17.7734	100.0	23.456	4.3247	23.456	-	23.456
AG1 SIS 2024 TARA	CRETE_EC_BP - STJOHN Ckt #1 345 kV	345	1399	Single	AEP_P1-2_#695_1681	154.14	157.5	0.0628	9.0399	100.0	38.368	7.0741	38.368	-	38.368
AG1 SIS 2024 TARA	UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Single	COMED_P1-2_765-L11215__-S	152.74	155.13	0.08079	17.7734	100.0	210.944	38.8928	210.944	-	210.944
AG1 SIS 2024 TARA	ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.28	130.76	0.0666	14.6527	100.0	0.0944	0.0944	0.512	-	0.0944
AG1 SIS 2024 TARA	STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	128.28	130.76	0.0666	14.6527	100.0	4.0002	4.0002	21.696	-	4.0002
AG1 SIS 2024 TARA	JEFRSO - JEFRSO Ckt #2 765/345 kV	765/345	3039	Single	AEP_P1-2_#709_546	108.14	110.45	0.10432	22.951	100.0	18	N/A	N/A	18	18

Appendix D: PJM ESS Results

The tables below show the generation deliverability results for the discharging/generating mode with of the batteries at their points of interconnection in the PJM Summer case.

The column headings are explained below:

- “Monitored Facility”: the limiting facility.
- “Voltage (kV)”: the operating voltage(s) of the Monitored Facility.
- “Rating”: the long-time-emergency rating of the facility following N-1 contingencies.
- “Contingency Type”: this is the type of contingency.
- “Contingency”: the outage taken on the system resulting in the flows on the Monitored Facility.
- “Pre-Queue Loading %”: this is the loading without the ESS injection.
- “Post Queue Loading %”: this is the impact from the ESS injections. It is determined by the MW size as well as the DFAX of the Batter Storage injections onto this facility (i.e., the percentage of project output that flows across the limiting facility).
- “Reinforcement Cost ($MM)”: the estimated cost in million dollars to replace the transformer or rebuild or reconductor the transmission line.
- “DFAX”: The impact of a generator on a given Monitored Facility.
- “Impact” (MW): The number of Megawatts the project contributes to the flow on the Monitored Facility
- “Cost Allocation (%)”: The percentage of responsibility for the cost of the network upgrade. This is based on relative Impact of each project to the Monitored Facility.
- “Cost Allocation ($MM)”: The cost of the network upgrade that the project is responsible for based on the Cost Allocation percentage.

Table 1: AG1-298 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Breaker	COMED_P4_112-65-BT3-4__	218.07	225.62	36.64	0.1886	94.2987	77.65	28.45
BURNHAM _B - SHEFFIELD Ckt #1 345 kV	345	1441	Breaker	COMED_P4_112-65-BT3-4__	112.53	120.41	3.32	0.28467	142.3375	91.05	3.02

Table 2: AG2-357 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
WILTON_3M - WILTON Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_112-65-BT5-6__	190.46	196.06	18.00	0.28552	71.3804	76.52	13.77

Table 3: AG2-545 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
AURORA_EC_RP - ELECT_JCT_4R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_154-45-BT2-3__	104.16	110.62	0.84	0.25398	101.5917	100	0.84
ESS_W407M_9T - ESS_W407K_9T Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L16704T	97.48	104.88	2.06	0.27703	110.8128	100	2.06
WAYNE_R - ESS_W407M_9T_1 Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L16704T	97.35	104.72	4.83	0.27703	110.8128	100	4.83
ZION_EC _RP - ZION_STA_R Ckt #1 345 kV	345	1201	Single	COMED_P1-2_345-L2221__R-N	100.04	104.08	3.53	0.0788	31.5186	66.36	2.34
ESS_W407K_9T - AURORA_EC_RP Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L16704T	96.5	103.9	0.51	0.27703	110.8128	100	0.51
LIBERTYVI_R - P_HTS_117_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_016-45-BT6-11_	97.62	102.35	9.07	0.17456	69.8225	100	9.07

Table 4: AF2-441 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Breaker	COMED_P4_112-65-BT3-4__	218.07	225.62	36.64	0.19003	27.1367	22.35	8.19
AF2-359TAP - OLIVE Ckt #1 345 kV	345	971	Breaker	COMED_P4_112-65-BT4-5__	205.44	205.66	23.46	0.09009	12.8647	n/a	0
ALLEN - RPMONE Ckt #1 345 kV	345	897	Breaker	AEP_P4_#7445_05MARYSV 765_B	196.19	196.26	78.14	0.07933	11.3285	n/a	0
WILTON_3M - WILTON Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_112-65-BT5-6__	190.46	196.06	18.00	0.1534	21.9052	23.48	4.23
WILTON_4M - WILTON Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_112-65-BT2-3__	192.33	192.68	18.00	0.15664	22.3677	n/a	0
JEFRSO - CLIFTY Ckt #Z1 345 kV	345	1868	Breaker	AEP_P4_#6189_05HANG R 765_D1	188.81	188.84	2.56	0.10383	14.8273	n/a	0
UNIV_PK_N_RP - AF2-359_TAP Ckt #1 345 kV	345	971	Breaker	COMED_P4_112-65-BT4-5__	179.64	179.93	210.94	0.09009	12.8647	n/a	0
AG1-410TAP - MADDOX Ckt #1 345 kV	345	1301	Breaker	AEP_P4_#7445_05MARYSV 765_B	169.39	169.44	13.33	0.07699	10.9936	n/a	0
CRETE_EC_BP - STJOHN Ckt #1 345 kV	345	1399	Single	AEP_P1-2_#695_1681	161.46	161.61	38.37	0.08699	6.9592	n/a	0
RPMONE - AG1-410_TAP Ckt #1 345 kV	345	1301	Breaker	AEP_P4_#7445_05MARYSV 765_B	157.47	157.53	27.49	0.07699	10.9936	n/a	0
MARYSV - MARYSV Xfmr #2 765/345 kV	765/345	1868	Breaker	AEP_P4_#7222_05MALIS 765_D	151.74	151.78	18.00	0.05471	7.8126	n/a	0
MON12 - LALLENDORF Ckt #1 345 kV	345	1702	Tower	ATSI-P7-1-TE-138-025T-A	148.42	148.45	75.04	0.06448	9.2071	n/a	0
GREENACRET - OLIVE Ckt #1 345 kV	345	971	Breaker	COMED_P4_112-65-BT3-4__	143.06	143.49	150.78	0.094	13.4236	n/a	0
AF2-137TAP - MARYSV Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	142.9	142.96	81.75	0.26006	37.136	n/a	0
DUMONT - SORENS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	133.61	133.71	7.63	0.24289	34.6844	n/a	0
E_FRANKFO_B - CRETE_EC_BP Ckt #1 345 kV	345	1399	Single	COMED_P1-2_765-L11215__-S	131.02	131.18	7.48	0.08856	7.0848	n/a	0
ST_JOHN_T - GREEN_ACRE Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	130.6	131.17	0.09	0.07724	6.1788	n/a	0
STJOHN - ST_JOHN_T Ckt #1 345 kV	345	1091	Single	AEP_P1-2_#695_1681	130.59	131.16	4.00	0.07724	6.1788	n/a	0
WILTON - DUMONT Ckt #1 765 kV	765	4105	Tower	COMED_P7-1_345-L0103__R-S_+_345-L0104__B-S	129.85	131.13	98.92	0.23215	33.1506	37.78	37.37
SORENS - AF2-137_TAP Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	130.93	131	45.78	0.26006	37.136	n/a	0
MOROCCO - ALLEN Ckt #1 345 kV	345	1793	Breaker	ATSI-P2-3-TE-345-033T	130.33	130.35	4.96	0.05686	8.1194	n/a	0
AD1-103TAP - BEAVER Ckt #1 345 kV	345	1742	Single	ATSI-P1-2-OEC-345-810	129.47	129.47	18.25	0.05568	4.4547	n/a	0
GREEN_ACRE - GREENACRE_T Ckt #1 345 kV	345	1091	Breaker	COMED_P4_112-65-BT3-4__	127.35	127.73	0.09	0.094	13.4236	n/a	0
DAV-BE - AD1-103_TAP Ckt #1 345 kV	345	1742	Single	ATSI-P1-2-OEC-345-810	126.83	126.83	16.85	0.05568	4.4547	n/a	0
MADDOX - E_LIMA Ckt #1 345 kV	345	1868	Breaker	AEP_P4_#7445_05MARYSV 765_B	126.56	126.59	19.02	0.07673	10.9569	n/a	0
DAV-BE - HAYES Ckt #1 345 kV	345	1878	Single	238569 02BEAVER 345 907200 AD1-103 TAP 345 1	125.37	125.38	35.11	0.05758	4.606	n/a	0
BURNHAM0R - MUNSTER Ckt #1 345 kV	345	1441	Breaker	COMED_P4_112-65-BT3-4__	123.23	123.35	5.20	0.10189	14.5502	n/a	0
BURNHAMB - SHEFFIELD Ckt #1 345 kV	345	1441	Breaker	COMED_P4_112-65-BT3-4__	112.53	120.41	3.32	0.09793	13.9849	8.95	0.30
ELDERBERRY - DUMONT Ckt #1 345 kV	345	1868	Breaker	AEP_P4_#8165_05OLIVE 345_B1	120.3	120.34	8.44	0.06483	9.2572	n/a	0
HAYES - BEAVER Ckt #1 345 kV	345	1844	Single	238569 02BEAVER 345 907200 AD1-103 TAP 345 1	119.26	119.27	35.11	0.05859	4.6875	n/a	0
GOODINGS_4B - GOODINGS_3B Ckt #1 345 kV	345	1802	Single	COMED_P1-2_765-L11215__-S	118.7	118.92	0.18	0.05041	4.0332	n/a	0
JEFRSO - JEFRSO Xfmr #2 765/345 kV	765/345	3039	Breaker	AEP_P4_#6189_05HANG R 765_D1	116.98	116.99	18.00	0.10383	14.8273	n/a	0
LEMOYN - DAV-BE Ckt #1 345 kV	345	1683	Single	ATSI-P1-2-TE-345-601	115.52	115.53	12.69	0.06789	5.4314	n/a	0
TANNER - M.FORT Ckt #1 345 kV	345	2151	Single	AEP_P1-2_#7441_100545-A	113.56	113.57	2.50	0.06241	4.9928	n/a	0
AB2-067TAP - KAMMER Ckt #1 765 kV	765	4142	Single	AEP_P2-1_242516 05MOUNTN 765 242920 05BELMON 765 1	112.41	112.41	43.60	0.15686	12.5492	n/a	0
MARYSV - MALIS Ckt #1 765 kV	765	4142	Breaker	AEP_P4_#2942_05KAMMER 765_PP	108.26	108.28	27.25	0.1495	21.349	n/a	0
COLLINS2M - COLLINS Xfmr #1 345/765 kV	345/765	1379	Single	COMED_P1-2_765-L2315___-S	106.83	107.13	18.00	0.05226	4.1806	n/a	0
GAVIN - MOUNTN Ckt #1 765 kV	765	4571	Breaker	AEP_P4_#8075_05MARYSV 765_A2	105.99	106.01	11.99	0.13143	18.7684	n/a	0

OLIVE - COOK Ckt #1 345 kV	345	1409	Breaker	AEP_P4_#8166_05OLIVE 345_E1	105.69	105.78	14.04	0.06994	9.9881	n/a	0
OLIVE - ELDERBERRY Ckt #1 345 kV	345	1539	Breaker	AEP_P4_#8165_05OLIVE 345_B1	104.11	104.17	0.33	0.06856	9.7902	n/a	0
BAYSH - DAV-BE Ckt #1 345 kV	345	1878	Single	ATSI-P1-2-TE-345-602	103.31	103.32	12.21	0.06657	5.326	n/a	0

Table 5: AH2-015 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
J1180_TAP - SULLIVAN Ckt #1 345 kV	345	1466	Single	EXT_P12:345:DEI-AMIL:AMEREN KANSAS-SUGAR CREEK 34545	162.08	163.17	46.88	0.07227	7.9499	46.77	21.93
AF2-041_TAP - ELECT_JCT_B Ckt #1 345 kV	345	1656	Breaker	COMED_P4_144-45-BT7-8__	153.88	155.29	129.89	0.23757	26.1329	36.88	47.90
AG1-434_TAP - AF2-041_TAP Ckt #1 345 kV	345	1656	Breaker	COMED_P4_144-45-BT6-8__	139.14	140.54	25.92	0.23725	26.0973	100	25.92
AF1-012_TAP - AG1-434_TAP Ckt #1 345 kV	345	1656	Breaker	COMED_P4_144-45-BT6-8__	136.5	137.9	42.56	0.23725	26.0973	100	42.56
NELSON_B - AF1-012_TAP Ckt #1 345 kV	345	1656	Breaker	COMED_P4_144-45-BT6-8__	132.58	133.98	6.55	0.23725	26.0973	100	6.549
ELECT_JCT_B - LOMBARD_B Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L16704T	118.34	120.04	10.41	0.16657	18.3228	66.47	6.92
AF1-280_TAP - LEE_CO_EC_BP Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	112.86	116.02	2.36	0.33049	36.3544	74.97	1.77
NELSON_B - AF1-280_TAP Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	97.78	100.99	5.30	0.33049	36.3544	74.97	3.98

Table 6: AH2-204 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
FREEPORT_RT - ESS_B427_4T Ckt #1 138 kV	138	193	Tower	COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-A	170.54	259.28	3.15	0.9999	169.9828	100	3.15
LANCASTER_R - PECATONIC_B Ckt #1 138 kV	138	275	Tower	COMED_P7-1_138-L11902_B-R_+_138-L19414GR-R-A	119.62	183.73	24.82	0.9999	169.9828	100	24.82
PECATONIC_B - WEMPLETOW_R Ckt #1 138 kV	138	275	Tower	COMED_P7-1_138-L11902_B-R_+_138-L19414GR-R-A	115.12	180.29	14.60	0.9999	169.9828	100	14.60
LANCASTER_R - FREEPORT_RT Ckt #1 138 kV	138	336	Tower	COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-B	106.37	157.18	1.43	0.99484	169.1228	100	1.428
GARDEN_PR_R - SILVER_LK_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	145.54	150.57	108.85	0.18331	31.1635	38.58	42.00
CHERRY_VA_B - GARDEN_PR_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_144-45-BT7-8__	133.96	140.46	56.07	0.21403	36.3843	37.79	21.19
ESS_B427_4T - S_PECATON_R Ckt #1 138 kV	138	498	Tower	COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-B	66.08	100.46	6.05	0.9999	169.9828	100	6.05

Table 7: AH2-259 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
PLANO_3M - PLANO Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_167-45-BT5-6__	134.63	138.52	18.00	0.28679	43.0182	82.74	14.89
PLANO_4M - PLANO Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_167-45-BT9-12_	133.93	137.48	18.00	0.26571	39.8564	80.65	14.52
WILTON - DUMONT Ckt #1 765 kV	765	4105	Tower	COMED_P7-1_345-L0103__R-S_+_345-L0104__B-S	129.85	131.13	98.92	0.36398	54.5965	62.22	61.55
PLANO_B - ELECT_JCT_B Ckt #1 345 kV	345	1341	Breaker	COMED_P4_111-45-L16703_	121.98	125	12.54	0.27412	41.1179	100	12.54
BRAIDWOOD_B - AD1-100_TAP Ckt #1 345 kV	345	1528	Breaker	COMED_P4_086-45-BT1-2__	122.89	123.98	3.26	0.10039	15.0578	100	3.26
PLANO_R - ELECT_JCT_3R Ckt #1 345 kV	345	1528	Breaker	COMED_P4_111-45-L16704T	117.36	120.24	12.50	0.29588	44.3815	100	12.50

Table 8: AH2-290 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
AE2-341_TAP - W_PLANO_R Ckt #1 138 kV	138	498	Tower	COMED_P7-1_138-L11106_B-R_+_345-L15502_B-R-A	130.93	139.78	5.12	0.72134	43.2804	100	5.12
PLANO_3M - PLANO Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_167-45-BT5-6__	134.63	138.52	18.00	0.14954	8.9726	17.26	3.11
PLANO_4M - PLANO Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_167-45-BT9-12_	133.93	137.48	18.00	0.15936	9.5613	19.35	3.48
W_PLANO _R - PLANO_R Ckt #1 138 kV	138	498	Tower	COMED_P7-1_138-L11106_B-R_+_345-L15502_B-R-A	124.03	132.87	0.33	0.72134	43.2804	100	0.33
ELECT_JCT_B - LOMBARD _B Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L16704T	118.34	120.04	10.41	0.15405	9.2432	33.53	3.49
MONTGOMER_RT - OSWEGO_R Ckt #1 138 kV	138	264	Breaker	COMED_P4_167-38-TR81___	100.81	111.72	1.15	0.50545	30.3272	100	1.15
WATERMAN_B - GLIDDEN_BT Ckt #1 138 kV	138	344	Breaker	COMED_P4_167-38-L14609_	97.85	106.02	0.57	0.48083	28.8501	100	0.57
KEWANEE _23 - AG1-435_TAP Ckt #1 138 kV	138	208	Breaker	COMED_P4_074-38-L7413__	86.28	100.03	3.52	0.67964	40.7785	58.31	2.05

Table 9: AH2-339 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
AB1-122_TAP1 - DRESDEN_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_012-45-BT4-5__	169.35	170.87	28.70	0.19892	21.8808	100	28.70
AG1-121_TAP - HENNEPIN_T Ckt #1 138 kV	138	208	Breaker	COMED_P4_074-38-L15508_	154.59	168.59	26.01	0.26989	29.6881	100	26.01
J1180_TAP - SULLIVAN Ckt #1 345 kV	345	1466	Single	EXT_P12:345:DEI-AMIL:AMEREN KANSAS-SUGAR CREEK 34545	162.08	163.17	46.88	0.08224	9.0462	53.23	24.95
AF2-128_TAP - CORBIN Ckt #1 138 kV	138	179	Single	COMED_P1-2_138-L6101___-S-B	145.21	149.81	7.36	0.07887	8.6762	100	7.36
TAZEWELL - AB1-122_TAP1 Ckt #1 345 kV	345	1479	Tower	COMED_P7-1_345-L9806__R-S_+_345-L19601_B-S	147.09	148.78	302.27	0.22323	24.5555	100	302.27
POWERTON - TOWERLINE Ckt #1 138 kV	138	214	Breaker	COMED_P4_074-38-L15508_	120.61	146.64	9.52	0.45723	50.2948	100	9.52
AG1-005_TAP - AF2-128_TAP Ckt #1 138 kV	138	179	Single	COMED_P1-2_138-L6101___-S-B	139.34	143.95	4.54	0.07887	8.6762	100	4.54
KEWANEE _13 - KEWANEE_N Ckt #1 138 kV	138	449	Tower	COMED_P7-1_138-L6101___-S_+_138-L98105_R-S-B	121.24	128.64	0.01	0.30517	33.5691	100	0.01
AG1-435_TAP - AG1-121_TAP Ckt #1 138 kV	138	208	Breaker	COMED_P4_074-38-L15508_	112.95	126.97	2.15	0.26989	29.6881	100	2.15
HENNEEPIN_T - HENNEPIN_S Ckt #1 138 kV	138	305	Breaker	COMED_P4_074-38-L15508_	118.78	126.18	0.24	0.2144	23.5836	100	0.24
AF1-280_TAP - LEE_CO_EC_BP Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	112.86	116.02	2.36	0.11033	12.1361	25.03	0.59
TOULON_R - POWERTON Ckt #1 138 kV	138	194	Bus	COMED_P2-2_111_EJ-345B__1	94.41	115.03	15.91	0.29983	32.9815	100	15.91
NELSON_B - AF1-280_TAP Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	97.78	100.99	5.30	0.11033	12.1361	25.03	1.33
KEWANEE_23 - AG1-435_TAP Ckt #1 138 kV	138	208	Breaker	COMED_P4_074-38-L7413__	86.28	100.03	3.52	0.265	29.1505	41.69	1.47

Table 10: AH2-341 Summer Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
AF2-041_TAP - ELECT_JCT_B Ckt #1 345 kV	345	1656	Breaker	COMED_P4_144-45-BT7-8__	153.88	155.29	129.89	0.17892	44.729	63.12	81.99
GARDEN_PR_R - SILVER_LK_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_111-45-L11124_	145.54	150.57	108.85	0.19844	49.6093	61.42	66.85
CHERRY_VA_B - GARDEN_PR_R Ckt #1 345 kV	345	1479	Breaker	COMED_P4_144-45-BT7-8__	133.96	140.46	56.07	0.23956	59.8899	62.21	34.88
AG1-423_TP - WAYNE_B Ckt #1 345 kV	345	2058	Breaker	COMED_P4_138-45-BT23-45	132.31	134.89	19.86	0.22796	56.9901	100	19.86
AG1-119_TAP - AG1-423_TP Ckt #1 345 kV	345	2058	Breaker	COMED_P4_138-45-BT23-45	127.69	130.27	0.20	0.22796	56.9901	100	0.20
AB1-089_POI - AG1-119_TAP Ckt #1 345 kV	345	2058	Breaker	COMED_P4_138-45-BT23-45	120.79	123.38	9.24	0.22796	56.9901	100	9.24
BYRON_B - AB1-089_POI Ckt #1 345 kV	345	2058	Breaker	COMED_P4_138-45-BT23-45	110.01	112.7	5.91	0.22796	56.9901	100	5.91
ZION_EC _RP - ZION_STA_R Ckt #1 345 kV	345	1201	Single	COMED_P1-2_345-L2221__R-N	100.04	104.08	3.53	0.06392	15.9788	33.64	1.19

Table 11: AG1-298 Light Load Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
WILTON_4M - WILTON Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_112-65-BT2-3__	138.42	141.16	18.0	0.15402	77.0091	100.00	18.00
WILTON_3M - WILTON Xfmr #1 345/765 kV	345/765	1379	Breaker	COMED_P4_112-65-BT5-6__	135.81	138.52	18.0	0.15083	75.4167	100.00	18.00
STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	136.26	134.29	6.8	0.1838	91.9023	n/a	0
GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	113.43	111.34	27.8	0.09087	45.4332	n/a	0

Table 12: AF2-441 Light Load Results

Monitored Facility	Voltage (kV)	Rating (MVA)	Contingency Type	Contingency	Pre Queue Loading %	Post Queue Loading %	Reinforcement Cost ($MM)	Dfax	Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)
STILLWELL - DUMONT Ckt #1 345 kV	345	1409	Single	COMED_P1-2_765-L11215__-S	136.26	134.29	6.8	0.18524	31.4904	n/a	0.00
GREENACRE_T - OLIVE Ckt #1 345 kV	345	971	Single	AEP_P1-2_#695_1681	113.43	111.34	27.8	0.09115	15.4948	n/a	0.00

Appendix E: MISO BESS Unit Results

The below tables show the generation deliverability results for the discharging/generating mode with of the batteries at their POIs in the ~~PJM Summer~~respective MISO cases.

The column headings are explained below:

- "Monitored Facility": the limiting facility.
- "Voltage (kV)": the operating voltage(s) of the Monitored Facility.
- "Rating": the long-time-emergency rating of the facility following N-1 contingencies.
- "Contingency Type": this is the type of contingency; four different types - Single, Bus, Tower, Breaker.
- "Contingency": the outage taken on the system resulting in the flows on the Monitored Facility.
- "Pre-Queue Loading %": this is the loading without the Battery Storage injection.
- "Post Queue Loading %": this is the impact from the Battery Storage injections. It is determined by the MW size as well as the dfax of the Batter Storage injections onto this facility (i.e., the percentage of project output that flows across the limiting facility).
- "Reinforcement Cost ($MM)": the estimated cost in million dollars to replace the transformer or rebuild or reconductor the transmission line.
- "Dfax": The impact of a generator on a given Monitored Facility.
- "Impact" (MW): The number of Megawatts the project contributes to the flow on the Monitored Facility
- "Cost Allocation (%)": The percentage of responsibility for the cost of the network upgrade. This is based on relative Impact of each project to the Monitored Facility.
- "Cost Allocation ($MM)": The cost of the network upgrade that the project is responsible for based on the Cost Allocation percentage.

Table 1: J1882 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	LOCKPORT - KENDALL 345 kV ckt 1	345	16.06	222	CE	Base Case	116.44	114.11	79.48	0.05759	2.62	3.30%	$ 0.31	9.4754	51.392	-	9.4754

Table 2: J1882 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement (Transformer) Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	LOCKPORT - KENDALL 345 kV ckt 1	16.06	-	345	1448	222	CE	Base Case	127.49	1687.14	158.9	5.78%	2.6	117.63	9.4754	51.392	-	2.21%	ER Upgrade
NRIS	MASON_IL 138/69.0 kV xfmr 1	-	-	138/69	56	357	AMIL	Base Case	123.74	36.72	32.57	6.69%	3.01	3.01	-	-	6	100.00%	6.00

Table 3: J1973 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	CAYUGA - 08NUCOR 345 kV ckt 1	32.29	-	345	1279	208	DEI	OLIVE - AF1-215 TAP 345 kV ckt 2	114.16	1066.61	393.53	7.48%	2.99	203.77	19.0511	103.328	1.47%	0.2795
NRIS	ROCKPT - JEFRSO 765 kV ckt 1	128.91	-	765	3854	205	AEP	J2201 POI - KENZIG ROAD 345 kV ckt 1	106.81	3332.82	593.6	7.35%	2.94	329	140.5119	-	0.89%	1.2556
NRIS	NUCOR - WHITST 345 kV ckt 1	27.99	-	345	1195	208	DEI	OLIVE - AF1-215 TAP 345 kV ckt 2	101.02	811.21	393.53	7.48%	2.99	203.77	16.5141	89.568	1.47%	0.2423

Table 4: J1975 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	ROCKPT - JEFRSO 765 kV ckt 1	128.91	-	765	3854	205	AEP	J2201 POI - KENZIG ROAD 345 kV ckt 1	106.81	3332.82	593.6	10.07%	4.03	329	140.5119	-	1.22%	1.721

Table 5: J2124 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Sh Charging	MAHOMET_2 - MAHOMET_1 Ckt #Z 138 kV	138	0.1	357	AMIL	P23:345:AMIL::RISING:V13	105.63	84.59	21.11	-0.21315	21.11	100.00%	$ 0.04	0.037	0.17	-	0.037

Table 6: J2124 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	CAYUGA - NUCOR Ckt #1 345 kV	32.29	-	345	1279	208	DEI	OLIVE - AF1-215 TAP 345 kV ckt 2	114.16	1066.61	393.53	6.66%	6.66	203.77	19.0511	103.328	3.27%	0.6227
NRIS	ROCKPT - JEFRSO Ckt #1 765 kV	128.91	-	765	3854	205	AEP	J2201 POI - KENZIG ROAD 345 kV ckt 1	106.81	3332.82	593.6	6.59%	6.59	329	140.5119	-	2.00%	2.8145
NRIS	NUCOR - WHITST Ckt #1 345 kV	27.99	-	345	1195	208	DEI	OLIVE - AF1-215 TAP 345 kV ckt 2	101.02	811.21	393.53	6.66%	6.66	203.77	16.5141	89.568	3.27%	0.5397

Table 7: J2159 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	HUTSONVL - HEATH Ckt #1 138 kV	11.4	-	138	175	357	AMIL	Base Case	118.61	83.08	124.48	29.58%	29.58	44.37	4.218	19.38	66.67%	2.812
NRIS	ROCKPT - JEFRSO Ckt #1 765 kV	128.91	-	765	3854	205	AEP	J2201 POI - KENZIG ROAD 345 kV ckt 1	106.81	3332.82	593.6	10.25%	10.25	329	140.5119	-	3.12%	4.378

Table 8: J2161 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	LOCKPORT_B - KENDALL _BU Ckt #1 345 kV	345	16.06	222	CE	Base Case	116.44	114.11	79.48	0.05659	2.85	3.59%	$ 0.34	9.4754	51.392	-	9.4754

Table 9: J2161 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	KENDALL_BU - LOCKPORT_B Ckt #1 345 kV	16.06	-	345	1448	222	CE	Base Case	127.49	1687.14	158.9	5.68%	5.68	117.63	9.4754	51.392	4.83%	ER Upgrade
NRIS	J2186_POI - 7MAPLE_RIDGE Ckt #1 345 kV	23.21	-	345	1195	357	AMIL	AA2-116_POI - AA2-116_MAIN 345 kV ckt 1	117.22	369.12	1031.68	30.37%	30.4	714.23	13.6939	74.272	4.26%	0.5829

Table 10: J2170 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	P7:345:AEP:I&M SULLIVAN - AEP DARWIN 345	101.05	104.7	47.58	0.31499	47.58	100.00%	$ 119.90	119.9	119.9	-	119.9
Sh Charging	J1701_POI - IPAVA_1 Ckt #1 138kV	138	7.6	901/357	Are_901/AMIL	Base Case	108.08	112.7	4.82	-0.09709	4.82	100.00%	$ 2.81	2.812	12.92	-	2.812

Table 11: J2170 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	ROCKPT - JEFRSO Ckt #1 765 kV	128.91	-	765	3854	205	AEP	52016 J2201 POI 345 326569 7KENZIG ROAD 345 1	106.81	3332.82	593.6	24.01%	36.02	329	140.5119	-	10.95%	ER Upgrade

Table 12: J2195 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Sh Charging	J1145_POI - J1965_POI Ckt #1 345 kV	345	9.46	356	AMMO	Base Case	180.18	162.97	118.71	-0.05141	5.21	4.39%	$ 1.33	5.5814	30.272	-	30.272
Sh Charging	J1965_POI - MONTGMRY Ckt #1 345 kV	345	18.54	356	AMMO	Base Case	173.69	162.86	97.15	-0.05144	5.22	5.37%	$ 3.19	10.9386	59.328	-	59.328

Table 13: J2195 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	AE1-172_TAP - AD1-100_TAP2 Ckt #1 345 kV	14.69	-	345	1364	222	CE	Base Case	114.48	802.4	759.12	6.68%	6.68	174.05	8.6671	47.008	3.84%	0.3326
NRIS	ROCKPT - JEFRSO Ckt #1 765 kV	128.91	-	765	3854	205	AEP	J2201 POI 345 - 7KENZIG ROAD 345 1	106.81	3332.82	593.6	8.16%	8.16	329	140.5119	-	2.48%	3.4850

Table 14: J2197 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Sh Charging	J1145_POI - J1965_POI Ckt #1 345 kV	345	9.46	356	AMMO	Base Case	180.18	162.97	118.71	-0.05216	5.29	4.46%	$ 1.35	5.5814	30.272	-	30.272
Sh Charging	J1965_POI - MONTGMRY Ckt #1 345 kV	345	18.54	356	AMMO	Base Case	173.69	162.86	97.15	-0.05219	5.29	5.45%	$ 3.23	10.9386	59.328	-	59.328

Table 15: J2197 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	ROCKPT - JEFRSO Ckt #1 765 kV	128.91	-	765	3854	205	AEP	J2201 POI 345 - 7KENZIG ROAD 345 1	106.81	3332.82	593.6	9.03%	9.03	329	140.5119	-	2.74%	3.8566

Table 16: J2376 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.05076	5.08	0.61%	$ 0.25	7.493	40.64	40.64
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.06677	6.68	1.39%	$ 1.67	119.9	119.9	119.9
Summer Peak	ORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.06623	6.62	1.63%	$ 0.19	11.8	64	11.8
Summer Peak	ORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.06623	6.62	1.63%	$ 0.11	6.7673	36.704	6.7673
SH Charging	J2376_POI - PANA_1 Ckt #1 138 kV	138	11.5	357	AMIL	J2694POI - COFFEN-N 345 1	140.15	57.77	65.48	-0.65478	65.48	100.00%	$ 19.55	4.255	19.55	19.55
SH Charging	ISHI - HERRICK_TAP Ckt #1 69.0 kV	69	6.6	357	AMIL	P22:138:AMIL::PANA:1	108.21	44.09	11.75	-0.11751	11.75	100.00%	$ 2.11	2.112	9.9	2.112
SH Charging	PANTHER - PANA_TAP Ckt #1 69.0 kV	69	4.06	357	AMIL	P22:138:AMIL::PANA:1	114.25	49.93	11.75	-0.11751	11.75	100.00%	$ 1.30	1.2992	6.09	1.2992
SH Charging	LAKEWOOD - HERRICK_TAP Ckt #1 69.0 kV	69	2.5	357	AMIL	P22:138:AMIL::PANA:1	111.12	46.93	11.75	-0.11751	11.75	100.00%	$ 0.80	0.8	3.75	0.8
SH Charging	LAKEWOOD - PANA_TAP Ckt #1 69.0 kV	69	12	357	AMIL	P22:138:AMIL::PANA:1	114.13	49.89	11.75	-0.11751	11.75	100.00%	$ 3.84	3.84	18	3.84

Table 17: J2377 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	MCLEAN_R - PONTIAC_R Ckt #1 345 kV	345	10.39	222	CE	P12:COMED345:L8002::S:SRT:A_Dup1	120.64	73.04	134.03	0.21943	67.01	50.00%	$ 3.06	6.1301	33.248	6.1301
Summer Peak	DRESDEN_R - AD1-133_TAP Ckt #1 345 kV	345	20.14	222	CE	Base Case	115.88	82.12	154.12	0.09138	27.91	18.11%	$ 2.15	11.8826	64.448	11.8826
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.12572	38.39	9.43%	$ 1.11	11.8	64	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.12572	38.39	9.43%	$ 0.64	6.7673	36.704	6.7673

Table 18: J2379 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076_POI - GIBSON Ckt #1 345 kV	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.0798	16.28	0.88%	$ 0.39	8.083	43.84	43.84
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.06633	13.53	1.62%	$ 0.66	7.493	40.64	40.64
Summer Peak	J2662_POI - CASEY Ckt #1 345 kV	345	2.5	357	AMIL	J3076POI - GIBSON 345 kV ckt 1	136.42	19.29	758.72	0.40083	81.77	10.78%	$ 0.86	1.475	8	8
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.08065	16.45	3.43%	$ 4.12	119.9	119.9	119.9
Summer Peak	J2662_POI - NEWTON Ckt #1 345 kV	345	24.04	357	AMIL	J3076POI - GIBSON 345 kV ckt 1	103.23	19.18	439.74	0.40283	82.18	18.69%	$ 2.65	14.1836	76.928	14.1836

Table 19: J2379 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	J1266_POI - WSALEM_1 Ckt #1 138 kV	-	2.26	138	264	701/357	central prior queud/AMIL	J2033 POI - XENIA 345 kV ckt 1	187.98	123.47	372.79	6.10%	12.2	266.45	0.836	3.842	4.58%	0.176
NRIS	J3130_POI - J1266_POI Ckt #1 138 kV	1.98	-	138	240	701/357	central prior queud/AMIL	J1241 POI - MTVERNW 345 kV ckt 1	204.96	123.34	368.56	6.10%	12.2	266.45	0.733	3.366	4.58%	0.154
NRIS	KINMUNDY_S - J3130_POI Ckt #1 138 kV	6.09	-	138	240	357	AMIL	J1241 POI - MTVERNW 345 kV ckt 1	186.04	123.82	322.68	6.10%	12.2	220.57	2.253	10.353	5.53%	0.571
NRIS	J3224_POI - KINMUNDY_S Ckt #1 138 kV	20.31	-	138	175	357	AMIL	J2033 POI - XENIA 345 kV ckt 1	100.73	20.24	160.33	9.68%	19.35	114.54	7.515	34.527	16.89%	1.269
NRIS	J1422_POI - ALBION_N Ckt #1 138 kV	-	5.87	138	192	357	AMIL	J1241 POI - MTVERNW 345 kV ckt 1	119.52	-45.74	275.22	6.62%	13.23	97.86	2.172	9.979	13.52%	0.294
NRIS	TANNER - J3224_POI Ckt #1 138 kV	7.29	-	138	175	357	AMIL	J1241 POI - MTVERNW 345 kV ckt 1	119.41	20.14	188.84	9.73%	19.45	70.8	2.697	12.393	27.47%	0.741
NRIS	MTVERNW - ASHLEY Ckt #1 138 kV	12.17	-	138	202	357	AMIL	J1241 POI - MTVERNW 345 kV ckt 1	103.66	43.99	167.06	5.19%	10.39	107.24	4.503	20.689	9.69%	0.436

Table 20: J2383 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	DRESDEN_R - AD1-133_TAP Ckt #1 345 kV	345	20.14	222	CE	Base Case	115.88	82.12	154.12	0.05088	5.19	3.37%	$ 0.40	11.8826	64.448	11.8826
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.06389	6.52	1.36%	$ 1.63	119.9	119.9	119.9
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.06737	6.87	1.69%	$ 0.20	11.8	64	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.06737	6.87	1.69%	$ 0.11	6.7673	36.704	6.7673

Table 21: J2402 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076_POI - GIBSON Ckt #1 345 kV	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.16509	33.68	1.82%	$ 0.80	8.083	43.84	43.84
Summer Peak	ASTER - PR_STATE Ckt #1 345 kV	345	7.2	357	AMIL	Base Case	106.78	64.69	1250.84	0.07966	16.25	1.30%	$ 0.06	4.248	23.04	4.248
Summer Peak	J2662_POI - CASEY Ckt #1 345 kV	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.07521	15.34	1.04%	$ 0.02	1.475	8	1.475
Summer Peak	FRANKLIN - AKINTP Ckt #1 138 kV	138	5.28	361	SIPC	W_FRFT_E - NORRIS 345 1	100.36	35.67	47.36	0.05075	10.35	21.85%	$ 0.43	1.9536	8.976	1.9536

Table 22: J2413 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.05736	8.78	2.16%	$ 0.25	11.8	64	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.05736	8.78	2.16%	$ 0.15	6.7673	36.704	6.7673
Summer Peak	J2809_POI - GILMAN Ckt #1 138 kV	138	7.6	357	AMIL	Base Case	109.65	8.39	278.57	0.0837	12.81	4.60%	$ 0.13	2.812	12.92	2.812
SH Charging	GOOS_CRK - RISING Ckt #1 345 kV	345	14.6	357	AMIL	Base Case	100.78	59.27	225.91	-0.12763	19.14	8.47%	$ 0.73	8.614	46.72	8.614

Table 23: J2413 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate($MM)
NRIS	HOOPESTN_N - PAXTON_E_N Ckt #1 138 kV	20.88	-	138	325	357	AMIL	P12:345:AMIL::CLINTON:BROKAW:4535	135.08	0.02	438.99	58.79%	88.19	264.57	7.726	35.496	33.33%	11.831
NRIS	J2809_POI - GILMAN Ckt #1 138 kV	7.6	-	138	255	357	AMIL	BROKAW - TAZEWELL 345 kV ckt 1	154.52	67.07	326.97	8.56%	12.85	286.4	2.812	12.92	4.49%	ER Upgrade
NRIS	J2565_POI - J2809_POI Ckt #1 138 kV	-	0.025	138	255	357	AMIL	BROKAW - TAZEWELL 345 kV ckt 1	125.15	67.27	251.86	8.56%	12.85	211.28	0.00925	0.0425	6.08%	0.00056

Table 24: J2426 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076_POI - GIBSON Ckt #1 345 kV	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.07269	14.83	0.80%	$ 0.35	8.083	43.84	43.84
Summer Peak	J1266_POI - J3130_POI Ckt #1 138 kV	138	1.98	701/357	CLASSIC PQ/AMIL	J3224POI - TANNER 138 kV ckt 1	138.03	20.82	415.7	0.48836	99.63	23.97%	$ 0.81	0.7326	3.366	3.366
Summer Peak	J1266_POI - WSALEM_1 Ckt #1 138 kV	138	3.15	701/357	CLASSIC PQ/AMIL	J3224POI - TANNER 138 kV ckt 1	130.97	57.06	415.63	0.48828	99.61	23.97%	$ 0.28	1.1655	5.355	1.1655
Summer Peak	J2662_POI - CASEY Ckt #1 345 kV	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.15838	32.31	2.19%	$ 0.03	1.475	8	1.475
Summer Peak	J2794_POI - OTEGO Ckt #1 138 kV	138	12.33	357	AMIL	J3224POI - TANNER 138 kV ckt 1	143.94	35.69	332.63	0.4458	90.94	27.34%	$ 5.73	4.5621	20.961	20.961
Summer Peak	J2794_POI - KINMUNDY_N Ckt #1 138 kV	138	3.43	357	AMIL	J3224POI - TANNER 138 kV ckt 1	105.28	35.7	287.4	0.44625	91.04	31.68%	$ 0.40	1.2691	5.831	1.2691
Summer Peak	J3224_POI - KINMUNDY_S Ckt #1 138 kV	138	20.31	357	AMIL	P22:138:AMIL::RAMSEYEAST:1	150.76	56.85	321.93	0.44449	90.68	28.17%	$ 9.73	7.5147	34.527	34.527
Summer Peak	J3224_POI - TANNER Ckt #1 138 kV	138	7.29	357	AMIL	P22:138:AMIL::RAMSEYEAST:1	237.85	56.85	441.37	0.44332	90.44	20.49%	$ 2.54	2.6973	12.393	12.393
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.07009	14.3	2.98%	$ 3.58	119.9	119.9	119.9
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.07491	15.28	1.82%	$ 0.74	7.493	40.64	40.64
Summer Peak	OTEGO - RAMSEY_CIPS Ckt #1 138 kV	138	11.9	357	AMIL	J3224POI - TANNER 138 kV ckt 1	147.54	56.34	429.88	0.44435	90.65	21.09%	$ 4.27	4.403	20.23	20.23
Summer Peak	SNDVLSW - SANDV_TP Ckt #1 69.0 kV	69	6.83	357	AMIL	J3224POI - TANNER 138 kV ckt 1	124.41	59.91	38.62	0.06883	14.04	36.35%	$ 0.79	2.1856	10.245	2.1856
SH Charging	OTEGO - RAMSEY_CIPS Ckt #1 138 kV	138	11.9	357	AMIL	Base Case	120.02	54.29	109.67	-0.30886	61.77	56.32%	$ 2.48	4.403	20.23	4.403
SH Charging	J3224_POI - TANNER Ckt #1 138 kV	138	7.29	357	AMIL	P12:138:AMIL::OTEGO:RAMSEY-E:1653	109.84	37.48	124.23	-0.4458	89.16	71.77%	$ 1.94	2.6973	12.393	2.6973
SH Charging	J3224_POI - KINMUNDY_S Ckt #1 138 kV	138	20.31	357	AMIL	P12:138:AMIL::OTEGO:RAMSEY-E:1653	108.78	37.4	124.4	-0.44638	89.28	71.77%	$ 5.39	7.5147	34.527	7.5147
SH Charging	J2425_POI - ROOTBEER Ckt #1 345 kV	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.05021	10.04	6.92%	$ 0.54	7.7644	42.112	7.7644
SH Charging	J2425_POI - ENON_TP Ckt #1 345 kV	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.05021	10.04	6.92%	$ 0.24	3.4161	18.528	3.4161

Table 25: J2426 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	J3224_POI - TANNER Ckt #1 138 kV	7.29	-	138	175	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	204.98	4.61	354.1	31.51%	63.01	294.35	2.6973	12.393	21.41%	ER upgrade
NRIS	J1266_POI - WSALEM_1 Ckt #1 138 kV	-	2.26	138	264	701/357	central prior queud/AMIL	J2033 POI - XENIA 345 kV ckt 1	187.98	123.47	372.79	34.04%	68.08	266.45	0.836	3.842	25.55%	ER upgrade
NRIS	J3130_POI - J1266_POI Ckt #1 138 kV	1.98	-	138	240	701/357	central prior queud/AMIL	J2033 POI - XENIA 345 kV ckt 1	186.26	123.48	323.55	34.04%	68.08	266.45	0.7326	3.366	25.55%	ER upgrade
NRIS	KINMUNDY_S - J3130_POI Ckt #1 138 kV	6.09	-	138	240	357	AMIL	J2033 POI - XENIA 345 kV ckt 1	167.35	123.96	277.67	34.04%	68.08	220.57	2.2533	10.353	30.87%	ER upgrade
NRIS	KINMUNDY_S - J3224_POI Ckt #1 138 kV	20.31	-	138	175	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	142.22	4.66	244.22	31.56%	63.12	184.17	7.5147	34.527	34.27%	ER upgrade
NRIS	KINMUNDY_N - J2794_POI Ckt #1 138 kV	3.43	-	138	240	357	AMIL	J2747POI - EDWDSP 345 kV ckt 1	103.35	42.36	206.91	30.84%	61.68	166.93	1.2691	5.831	36.95%	ER upgrade

Table 26: J2532 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Cont Name	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	DRESDEN_R - AD1-133_TAP Ckt #1 345 kV	345	20.14	222	CE	Base Case	115.88	82.12	154.12	0.09427	19.23	12.48%	$ 1.48	11.8826	64.448	11.8826
Summer Peak	BLUEMOUND_B - PONTIAC_B Ckt #1 345 kV	345	27.35	222	CE	P4:COMEDBRO:45:BT3:4:SRT:A	110.46	72.05	44.99	0.22054	44.99	100.00%	$ 16.14	16.1365	87.52	16.1365
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.12616	25.74	6.32%	$ 0.75	11.8	64	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.12616	25.74	6.32%	$ 0.43	6.7673	36.704	6.7673

Table 27: J2536 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	MAZON_R - AD2-066_TAP Ckt #1 138 kV	138	6.14	222	CE	Base Case	115.88	56.95	73.61	0.16215	33.08	44.94%	$ 1.02	2.2718	10.438	2.2718
Summer Peak	DRESDEN_R - ESS_J339_R Ckt #1 138 kV	138	2.9	222	CE	Base Case	104.75	59.76	66.49	0.14622	29.83	44.86%	$ 0.48	1.073	4.93	1.073
Summer Peak	CHANNAHON_R - MAZON_R Ckt #1 138 kV	138	10.02	222	CE	Base Case	101.5	47.06	66.49	0.14622	29.83	44.86%	$ 1.66	3.7074	17.034	3.7074
SH Charging	CORBIN - AF2-128_TAP Ckt #1 138 kV	138	4.33	357/720	AMIL/Are_720	Base Case	106.84	63.68	32.61	-0.1219	24.38	74.76%	$ 1.20	1.6021	7.361	1.6021

Table 28: J2551 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	MAZON_R - AD2-066_TAP Ckt #1 138 kV	138	6.14	222	CE	Base Case	115.88	56.95	73.61	0.12041	13.51	18.35%	$ 0.42	2.2718	10.438	2.2718
Summer Peak	DRESDEN_R - ESS_J339_R Ckt #1 138 kV	138	2.9	222	CE	Base Case	104.75	59.76	66.49	0.10893	12.22	18.38%	$ 0.20	1.073	4.93	1.073
Summer Peak	CHANNAHON_R - MAZON_R Ckt #1 138 kV	138	10.02	222	CE	Base Case	101.5	47.06	66.49	0.10893	12.22	18.38%	$ 0.68	3.7074	17.034	3.7074
SH Charging	KEWANEE_23 - PUTNAM Ckt #1 138 kV	138	30.6	222/357	CE/AMIL	P23:138:AMIL::BUREAU:H7	110.71	48.34	23.16	-0.21051	23.16	100.00%	$ 11.32	11.322	52.02	11.322
SH Charging	CORBIN - AF2-128_TAP Ckt #1 138 kV	138	4.33	357/720	AMIL/Are_720	Base Case	106.84	63.68	32.61	-0.07486	8.23	25.24%	$ 0.40	1.6021	7.361	1.6021
SH Charging	AF2-128_TAP - AG1-005_TAP Ckt #1 138 kV	138	2.67	720/222	Are_720/CE	Base Case	98.96	57.14	32.61	-0.07486	8.23	25.24%	$ 0.25	0.9879	4.539	0.9879

Table 29: J2552 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact (Harmers Only)	Dfax		MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild ($MM
Summer Peak	QUAD_1_3-11 - ROCK_CK3 Ckt #1 345 kV		345	5	222/627	CE/ALTW	P55:161:MEC:HILLS:8T1 8T2:DIFF	126.26	111.33	91.38	0.2099	27.29	29.86%	$ 0.88	2.95	
Summer Peak	ELECT_JCT_B - LOMBARD_B Ckt #1 345 kV		345	17.64	222	CE	Base Case	107.48	98.87	21.95	0.05043	6.56	29.89%	$ 3.11	10.4076	
SH Charging	QUAD_8-10 - MEC_CORDOVA3 Ckt #1 345 kV		345	2.22	222/635	CE/MEC	P611:345-345:CE:CORDOVA:QUAD:1:QUAD:ESS H471:1	190.52	114.1	85.04	-0.38582	50.16	58.98%	$ 4.19	1.3098	

Table 30: J2575 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	KOCH - CINCNATI Ckt #1 69.0 kV	69	1.67	357	AMIL	P23:138:AMIL::TOWERLINE:H3	105.81	53.82	33.3	0.16487	33.3	100.00%	$ 0.53	0.5344	2.505	-	0.5344
Summer Peak	MIDWEST - PEKIN_ENERG Ckt #1 69.0 kV	69	0.06	357	AMIL	P23:138:AMIL::TOWERLINE:H11	161	94.63	21.23	0.10514	21.23	100.00%	$ 0.09	0.0192	0.09	-	0.09
Summer Peak	MIDWEST - GROB_TAP Ckt #1 69.0 kV	69	0.99	357	AMIL	P23:138:AMIL::TOWERLINE:H11	147.26	87.01	21.23	0.10514	21.23	100.00%	$ 1.49	0.3168	1.485	-	1.485
Summer Peak	COURT - COURT_TAP Ckt #1 69.0 kV	69	0.1	357	AMIL	P23:138:AMIL::TOWERLINE:H11	137.67	81.45	21.23	0.10514	21.23	100.00%	$ 0.15	0.032	0.15	-	0.15
Summer Peak	COURT - GROB_TAP Ckt #1 69.0 kV	69	0.48	357	AMIL	P23:138:AMIL::TOWERLINE:H11	145.32	85.71	21.23	0.10514	21.23	100.00%	$ 0.72	0.1536	0.72	-	0.72
Summer Peak	CINCY_TAP - EDWARDS1 Ckt #1 69.0 kV	69	0.97	357	AMIL	P23:138:AMIL::TOWERLINE:H11	155.95	88.65	29.42	0.14567	29.42	100.00%	$ 1.46	0.3104	1.455	-	1.455
Summer Peak	CINCY_TAP - CINCNATI Ckt #1 69.0 kV	69	3.67	357	AMIL	P23:138:AMIL::TOWERLINE:H11	148.06	87.01	29.42	0.14567	29.42	100.00%	$ 5.51	1.1744	5.505	-	5.505
Summer Peak	WHLR_45TAP - COURT_TAP Ckt #1 69.0 kV	69	2.07	357	AMIL	P23:138:AMIL::TOWERLINE:H11	127.2	75.25	21.23	0.10514	21.23	100.00%	$ 0.66	0.6624	3.105	-	0.6624
Summer Peak	WHLR_45TAP - EDWARDS1 Ckt #1 69.0 kV	69	0.32	357	AMIL	P23:138:AMIL::TOWERLINE:H11	127.16	75.19	21.23	0.10514	21.23	100.00%	$ 0.10	0.1024	0.48	-	0.1024
Summer Peak	2CINCNATI - 4CINCINATTI Xfmr #2 138 kV	138/69	-	357	AMIL	P23:138:AMIL::CINCINNATI:H3	213.88	56.3	164.33	0.48727	98.41	59.89%	$ 4.19	-	-	7	7
Summer Peak	4TOWERLINE - 4TAZEWELL Ckt #1 138 kV	138	6.22	357	AMIL	BROKAW - TAZEWELL 345 kV ckt 1	104.63	60.9	66.44	0.32898	66.44	100.00%	$ 2.30	2.3014	10.574	-	2.3014
Summer Peak	4CINCINATTI - 2CINCNATI Xfmr #1 69.0 kV	138/69	-	357	AMIL	P23:138:AMIL::CINCINNATI:H5	224.26	56.3	164.33	0.48727	98.41	59.89%	$ 4.19	-	-	7	7
SH Charging	GRAND_ISLND - TOPEKA Ckt #1 69.0 kV	69	6.13	357	AMIL	J3003POI - HAVANA2 138 V ckt 1	103.92	59.01	12.74	-0.06435	12.74	100.00%	$ 1.96	1.9616	9.195	-	1.9616

Table 31: J2607 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.10162	20.74	2.48%	$ 1.01	7.493	40.64	-	40.64
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.05969	12.18	2.54%	$ 3.05	119.9	119.9	-	119.9
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.05238	10.68	2.62%	$ 0.31	11.8	64	-	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.05238	10.68	2.62%	$ 0.18	6.7673	36.704	-	6.7673
Summer Peak	MORO - LACLEDE_NTP Ckt #1 138 kV	138	7.07	357	AMIL	P71:138-345:AMIL::COFFEEN:ROXFORD:51:WOODRIVER:ROXFORD:02	120.93	95.7	107.27	0.26661	54.38	50.69%	$ 1.33	2.6159	12.019	-	2.6159
SH Charging	J2694_POI - COFFEN-N Ckt #1 345 kV	345	8	357	AMIL	P23:138-345:AMIL::FARADAY:1	125.01	66.04	333.81	-0.26177	52.36	15.69%	$ 0.74	4.72	25.6	-	4.72
SH Charging	J2425_POI - ROOTBEER Ckt #1 345 kV	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.05652	11.3	7.79%	$ 0.60	7.7644	42.112	-	7.7644
SH Charging	J2425_POI - ENON_TP Ckt #1 345 kV	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.05652	11.3	7.79%	$ 0.27	3.4161	18.528	-	3.4161

Table 32: J2647 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076_POI - GIBSON Ckt #1 345 kV	345	13.7	357/208	AMIL/DEI	P23:138-345:AMIL::KANSAS:V23	186.64	7.8	966.13	0.26274	80.4	8.32%	$ 3.65	8.083	43.84	-	43.84
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.05667	17.34	2.07%	$ 0.84	7.493	40.64	-	40.64
Summer Peak	J2662_POI - CASEY Ckt #1 345 kV	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.10047	30.74	2.08%	$ 0.03	1.475	8	-	1.475
Summer Peak	J3076_POI - ALBION Ckt #1 345 kV	345	4.66	357	AMIL	J3076POI 345 - J3076SUB 345 1	101.9	NA	295.54	0.24503	74.98	25.37%	$ 0.70	2.7494	14.912	-	2.7494
Summer Peak	FRANKLIN - AKINTP Ckt #1 138 kV	138	5.28	361	SIPC	7W_FRFT_E 345 - 7NORRIS 345 1	100.36	35.67	47.36	0.07008	21.44	45.27%	$ 0.88	1.9536	8.976	-	1.9536

Table 33: J2627 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact (Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	2HAMLTNAM - 4HAMLTNAM Xfmr #1 138 kV	138/69	-	357	AMIL	P22:161:AECI:5PALMYR_AI:11	184.96	137.03	13.18	0.08616	13.18	100.00%	$ 7.00	-	-	7	7
Summer Peak	J2627_SUB - 4E_QUINCY_S Ckt #1 138 kV	138	1.17	801/357	CLASSIC STUD/AMIL	Base Case	107.14	0	152.76	0.99844	152.76	100.00%	$ 0.43	0.4329	1.989	-	0.4329
SH Charging	5PALMYR_AI - 7PALMYR_AI Xfmr #1 345 kV	345/161	-	330	AECI	P23:345:AMIL::HERLEMAN:V13	122.71	72.3	74.92	-0.30359	45.54	60.78%	$ 6.08	-	-	10	10
SH Charging	VIELE161 - _DENMARK5 Ckt #1 161 kV	161	13.1	627	ALTW	P23:345:AMMO::MAYWOOD:V43	120.72	45.21	41.57	-0.07816	11.72	28.19%	$ 1.37	4.847	22.27	-	4.847

Table 34: J2724 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact (Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	SIOUX - ROXFORD Ckt #1 345 kV	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.0616	18.84	2.25%	$ 0.91	7.493	40.64	-	40.64
Summer Peak	J1263_POI - KANSAS Ckt #1 345 kV	345	13	701/357	CLASSIC PQ/AMIL	P12:765:AEP:AEP ROCKP-AEP JEFF 765 ADJ ROCKP 400MW	120.37	59.93	308.27	0.20005	61.22	19.86%	$ 1.52	7.67	41.6	-	7.67
Summer Peak	J1263_POI - CASEY Ckt #1 345 kV	345	8	701/357	CLASSIC PQ/AMIL	P12:765:AEP:AEP ROCKP-AEP JEFF 765 ADJ ROCKP 400MW	116.21	34.12	309.42	0.20103	61.52	19.88%	$ 0.94	4.72	25.6	-	4.72
Summer Peak	JEFRSO - ROCKPT Ckt #1 765 kV	765	110	205	AEP	Base Case	113.92	111.18	479.1	0.10332	31.62	6.60%	$ 7.91	119.9	119.9	-	119.9

Table 35: J2853 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	DRESDEN_R - AD1-133_TAP Ckt #1 345 kV	345	20.14	222	CE	Base Case	115.88	82.12	154.12	0.05442	5.53	3.59%	$ 0.43	11.8826	64.448	-	11.8826
Summer Peak	LORETTO_B - AD1-100_TAP Ckt #1 345 kV	345	20	222	CE	Base Case	104.42	62.25	407.06	0.08068	8.2	2.01%	$ 0.24	11.8	64	-	11.8
Summer Peak	LORETTO_B - PONTIAC_B Ckt #1 345 kV	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.08068	8.2	2.01%	$ 0.14	6.7673	36.704	-	6.7673
Summer Peak	JACK_IND_S - JACKSNVL Ckt #1 138 kV	138	7.36	357	AMIL	Base Case	109.49	91.59	108.01	0.08601	8.74	8.09%	$ 0.22	2.7232	12.512	-	2.7232
Summer Peak	QUIVER - MASON_IL Ckt #1 138 kV	138	8.24	357	AMIL	Base Case	106.37	42.38	62	0.06489	6.6	10.65%	$ 0.32	3.0488	14.008	-	3.0488
Summer Peak	SPALDING - 4_PORTER Ckt #1 138 kV	138	5.5	360	CWLP	P23:138:CWLP:WESTCHESTER:WCB1	101.81	85.27	101.93	0.46824	47.6	46.70%	$ 0.95	2.035	9.35	-	2.035

Table 36: J2853 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	J2963_POI - PURO Ckt #1 138 kV	0.15	-	138	160	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	163.83	49.86	212.27	7.72%	7.72	156.16	0.0555	0.255	4.944%	0.0126
NRIS	SANJOSERAIL - TOWERLINE Ckt #1 138 kV	13.6	-	138	305	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	149.18	95.5	359.5	5.99%	5.99	57.51	5.032	23.12	10.416%	2.4081
NRIS	J3005_POI - GILLETT Ckt #1 138 kV	7.06	-	138	160	357	AMIL	P12:345:ATC-ITC:W-19:HLV_345:HCKRYCK3:NLL	157.01	0.73	250.5	7.17%	7.17	120.06	2.6122	12.002	5.972%	0.7168
NRIS	GILLETT - DOCKET Ckt #1 138 kV	8.56	-	138	202	357	AMIL	P12:138:CWLP:SPAULDING:WESTCHESTER:1	116.6	-30.98	266.51	13.57%	13.57	125.57	3.1672	14.552	10.807%	0.3423
NRIS	SHOCKEY - J3005POI Ckt #1 138 kV	1.83	-	138	160	357	AMIL	P12:138:CWLP:SPAULDING:WESTCHESTER:1	127.87	-1.36	205.94	8.40%	8.4	74.72	0.6771	3.111	11.242%	0.0761
NRIS	PURO - HAVANA3 Ckt #1 138 kV	12.0	-	138	305	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	120.57	49.69	318.05	7.72%	7.72	156.16	4.44	20.4	4.944%	0.2195
NRIS	YATES - MERE_138 Ckt #1 138 kV	-	19.3	138	159	357	AMIL	P12:345:AMIL-CE::BROKAW:MTPULASKI:18806	110.32	36.96	138.46	5.93%	5.93	85.55	7.141	32.81	6.932%	0.4950

Table 37: J2974 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	HULL - MARION2 Ckt #1 161 kV	161	7	357/356	AMIL/AMMO	P22:138:AMIL::HERLEMAN:1	125.99	25.01	162.46	0.70798	61.59	37.91%	$ 0.98	2.59	11.9	-	2.59
SH Charging	5PALMYR_AI - 7PALMYR_AI Xfmr #1 345 kV	345/161	-	330	AECI	P23:345:AMIL::HERLEMAN:V13	122.71	72.3	74.92	-0.34567	29.38	39.22%	$ 3.92	-	-	10	10
SH Charging	PALMYR_AI - HANW Ckt #1 161 kV	161	9.43	330/356	AECI/AMMO	J2972POI - HERLEMAN 138 kV ckt 1	113.62	60.95	39.07	-0.4596	39.07	100.00%	$ 3.49	3.4891	16.031	-	3.4891
SH Charging	SPALDNG - HANW Ckt #1 161 kV	161	6.92	330/356	AECI/AMMO	J2972POI - HERLEMAN 138 kV ckt 1	108.2	58.7	39.07	-0.4596	39.07	100.00%	$ 2.56	2.5604	11.764	-	2.5604
SH Charging	J2972_POI - HERLEMAN_1 Ckt #1 138 kV	138	8.35	357	AMIL	P22:345:AMMO::MONTGOMERY:A&B	NConv	52.22	59.79	-0.70343	59.79	100.00%	$ 14.20	3.0895	14.195	-	14.195

Table 38: J2974 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	J1268_POI - AUBURNTP Ckt #1 161 kV	-	7.39	161	224	356/330	AMMO/AECI	P12:345:MEC:HILLS:SUB T-SUB 93:1:REACTOR	141.13	82.7	233.43	7.12%	6.05	41	2.7343	12.563	14.756%	1.8538
NRIS	AUBURNTP - WINFIELD Ckt #1 161 kV	-	8.98	161	224	330/356	AMMO/AECI	P12:345:MEC:HILLS:SUB T-SUB 93:1:REACTOR	140.9	82.19	233.43	7.12%	6.05	41	3.3226	15.266	14.756%	2.2527

Table 39: J2998 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC % Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076POI - GIBSON 345 kV ckt 1	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.0922	18.81	1.02%	$ 0.45	8.083	43.84	-	43.84
Summer Peak	SIOUX - ROXFORD 345 kV ckt 1	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.11105	22.65	2.70%	$ 1.10	7.493	40.64	-	40.64
Summer Peak	CAHOKIA - TURKEY HILL 345 kV ckt 1	345	18.73	357	AMIL	Base Case	113.87	42.36	306.71	0.10293	21	6.85%	$ 0.76	11.0507	59.936	-	11.0507
Summer Peak	BALDWIN - BEEHIVE 345 kV ckt 1	345	31.16	357	AMIL	Base Case	109.12	48.72	262.78	0.0508	10.36	3.94%	$ 0.72	18.3844	99.712	-	18.3844
Summer Peak	ASTER - PR STATE 345 kV ckt 1	345	7.2	357	AMIL	Base Case	106.78	64.69	1250.84	0.14544	29.67	2.37%	$ 0.10	4.248	23.04	-	4.248
Summer Peak	J2662POI - CASEY 345 kV ckt 1	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.07404	15.1	1.02%	$ 0.02	1.475	8	-	1.475
Summer Peak	CAHOK - CENTERV 138 kV ckt 1	138	6.09	357	AMIL	Base Case	161.41	57.92	63.09	0.10087	20.58	32.62%	$ 3.38	2.2533	10.353	-	10.353
Summer Peak	J3069POI - HERZOG 138 kV ckt 1	138	1.94	357	AMIL	P12:345:AMIL::ASTER:PRAIRI ESTATE:4513	153.58	95.59	175.04	0.62003	126.49	72.26%	$ 2.38	0.7178	3.298	-	3.298
Summer Peak	S BELLEVLLE - HERZOG 138 kV ckt 1	138	12.11	357	AMIL	P12:345:AMIL::ASTER:PRAIRI ESTATE:4513	137.09	84.13	100.02	0.35626	72.68	72.67%	$ 14.96	4.4807	20.587	-	20.587
Summer Peak	J3074POI - STEELEVLEN 138 kV ckt 1	138	2.56	357	AMIL	Base Case	133.41	24.62	202.69	0.07898	16.11	7.95%	$ 0.08	0.9472	4.352	-	0.9472

Summer Peak	J3069POI - FAYETTEVLLE 138 kV ckt 1	138	2.56	357	AMIL	P12:345:AMIL::ASTER:PRAIRI ESTATE:4513	133.23	95.6	126.56	0.62037	126.56	100.00%	$ 0.95	0.9472	4.352	-	0.9472
Summer Peak	BEL17 RING - S BELLEVLLE 138 kV ckt 1	138	2.57	357	AMIL	Base Case	123.8	65.74	66.86	0.10683	21.79	32.59%	$ 0.31	0.9509	4.369	-	0.9509
SH Charging	J2425POI - ROOTBEER 345 kV ckt 1	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.08322	16.64	11.47%	$ 0.89	7.7644	42.112	-	7.7644
SH Charging	J2425POI - ENON_TP 345 kV ckt 1	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.08322	16.64	11.47%	$ 0.39	3.4161	18.528	-	3.4161

Table 40: J2998 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	J3074POI - STEELEVLE N 138 kV ckt 1	2.2	-	138	160	357	AMIL	J1306 POI - J3063POI 345 kV ckt 1	149.27	7.54	231.29	8.82%	17.63	177.13	0.814	3.74	9.953%	ER Upgrade
NRIS	JORD - 4W_FRFT_E 138 kV ckt 1	6.45	-	138	478	357	AMIL	P12:345:AMIL::MTVERNON-W:WESTFRANKFORT-E:4561	124.85	16.89	579.88	5.74%	11.48	395.26	2.3865	10.965	2.904%	0.0693
NRIS	J3069POI - HERZOG 138 kV ckt 1	1.94	-	138	338	357	AMIL	J1306 POI - J3063POI 345 kV ckt 1	115.86	50.57	341.04	60.54%	121.07	215.46	0.7178	3.298	56.191%	ER Upgrade
NRIS	FAYETTEVLLE - J3069POI 138 kV ckt 1	2.56	-	138	338	357	AMIL	J1306 POI - J3063POI 345 kV ckt 1	101.15	50.72	293.21	60.54%	121.07	167.63	0.9472	4.352	72.225%	ER Upgrade

Table 41: J3011 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076POI - GIBSON 345 kV ckt 1	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.09311	9.45	0.51%	$ 0.22	8.083	43.84	-	43.84
Summer Peak	J3011SUB - PR STATE 345 kV ckt 1	345	2.05	801/357	CLASSIC STUD/AMIL	Base Case	149.79	0	101.4	0.99899	101.4	100.00%	$ 6.56	1.2095	6.56	-	6.56
Summer Peak	SIOUX - ROXFORD 345 kV ckt 1	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.11793	11.97	1.43%	$ 0.58	7.493	40.64	-	40.64
Summer Peak	J2691POI - RUSH 345 kV ckt 1	345	27	356	AMMO	P23:345:AMIL::PRAIRIESTATE :V13	119.08	29.41	257.64	0.20861	21.17	8.22%	$ 1.31	15.93	86.4	-	15.93
Summer Peak	CAHOKIA - TURKEY HILL 345 kV ckt 1	345	18.73	357	AMIL	Base Case	113.87	42.36	306.71	0.05264	5.34	1.74%	$ 0.19	11.0507	59.936	-	11.0507
Summer Peak	BALDWIN - BEEHIVE 345 kV ckt 1	345	31.16	357	AMIL	Base Case	109.12	48.72	262.78	0.07658	7.77	2.96%	$ 0.54	18.3844	99.712	-	18.3844
Summer Peak	GATEWAY - PR STATE 345 kV ckt 1	345	43	357	AMIL	Base Case	105.63	0	357.7	0.1293	13.12	3.67%	$ 0.93	25.37	137.6	-	25.37
Summer Peak	J2662POI - CASEY 345 kV ckt 1	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.08266	8.39	0.57%	$ 0.01	1.475	8	-	1.475
SH Charging	J3011SUB - PR STATE 345 kV ckt 1	345	2.05	801/357	CLASSIC STUD/AMIL	Base Case	168.53	0	100	-0.99999	100	100.00%	$ 6.56	1.2095	6.56	-	6.56
SH Charging	J2425POI - ROOTBEER 345 kV ckt 1	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.08309	8.31	5.73%	$ 0.44	7.7644	42.112	-	7.7644
SH Charging	J2425POI - ENON_TP 345 kV ckt 1	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.08309	8.31	5.73%	$ 0.20	3.4161	18.528	-	3.4161

Table 42: J3011 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	JORD - 4W_FRFT_E 138 kV ckt 1	6.45	-	138	478	357	AMIL	P12:345:AMIL::MTVERNON-W:WESTFRANKFORT-E:4561	124.85	16.89	579.88	6.20%	6.2	395.26	2.3865	10.965	1.569%	0.0374

Table 43: 3031 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076POI - GIBSON 345 kV ckt 1	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.13512	27.56	1.49%	$ 0.65	8.083	43.84	-	43.84
Summer Peak	SIOUX - ROXFORD 345 kV ckt 1	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.07818	15.95	1.90%	$ 0.77	7.493	40.64	-	40.64
Summer Peak	GATEWAY - PR STATE 345 kV ckt 1	345	43	357	AMIL	Base Case	105.63	0	357.7	0.0536	10.93	3.06%	$ 0.78	25.37	137.6	-	25.37
Summer Peak	J2662POI - CASEY 345 kV ckt 1	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.14864	30.32	2.06%	$ 0.03	1.475	8	-	1.475
Summer Peak	WLTNVLSH - WLTNVLTP 138 kV ckt 1	138	2.68	357	AMIL	Base Case	164.68	0.32	203.59	0.99797	203.59	100.00%	$ 4.56	0.9916	4.556	-	4.556
SH Charging	J2425POI - ROOTBEER 345 kV ckt 1	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.05849	11.7	8.07%	$ 0.63	7.7644	42.112	-	7.7644
SH Charging	J2425POI - ENON_TP 345 kV ckt 1	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.05849	11.7	8.07%	$ 0.28	3.4161	18.528	-	3.4161

Table 44: J3031 NRIS Results

Model	Monitored Facility	Line Length (miles)	Estimated Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	JORD - 4W_FRFT_E 138 kV ckt 1	6.45	-	138	478	357	AMIL	P12:345:AMIL::MTVERNON-W:WESTFRANKFORT-E:4561	124.85	16.89	579.88	12.91%	25.82	395.26	2.3865	10.965	0.06532409	0.1559
NRIS	MTVERNW - ASHLEY 138 kV ckt 1	12.17	-	138	202	357	AMIL	J2690POI - MTVERNW 345 kV ckt 1	103.66	43.99	167.06	9.58%	19.15	107.24	4.5029	20.689	0.178571429	0.8041

Table 45: J3200 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact(Harmers Only)	Dfax	MW Impact	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	J3076POI - GIBSON 345 kV ckt 1	345	13.7	357/208	AMIL/DEI	Base Case	159.75	12.27	1851.62	0.08283	21.12	1.14%	$ 0.50	8.083	43.84	-	43.84
Summer Peak	SIOUX - ROXFORD 345 kV ckt 1	345	12.7	356/357	AMMO/AMIL	Base Case	147.4	24.79	837.77	0.12947	33.02	3.94%	$ 1.60	7.493	40.64	-	40.64
Summer Peak	CAHOKIA - TURKEY HILL 345 kV ckt 1	345	18.73	357	AMIL	P23:345:AMIL::PRAIRIESTATE:V13	133.98	41.68	101.79	0.39918	101.8	100.01%	$ 11.05	11.0507	59.936	-	11.0507
Summer Peak	CAHOKIA - GATEWAY 345 kV ckt 1	345	6.54	357	AMIL	P23:345:AMIL::PRAIRIESTATE:V13	127.68	10.14	114.86	0.28372	72.34	62.98%	$ 2.43	3.8586	20.928	-	3.8586
Summer Peak	J2662POI - CASEY 345 kV ckt 1	345	2.5	357	AMIL	Base Case	104.12	21.71	1475.29	0.0682	17.4	1.18%	$ 0.02	1.475	8	-	1.475
SH Charging	CAHOK - CENTERV 138 kV ckt 1	138	6.09	357	AMIL	P23:345:AMIL::TURKEYHILL:V9	118.8	39.84	75.39	-0.30157	37.7	50.01%	$ 1.13	2.2533	10.353	-	2.2533
SH Charging	KREN - PORTR_RD 138 kV ckt 1	138	5.9	357	AMIL	P23:345:AMIL::TURKEYHILL:V9	112.58	51.45	72.79	-0.29114	36.39	49.99%	$ 1.09	2.183	10.03	-	2.183
SH Charging	J2425POI - ROOTBEER 345 kV ckt 1	345	13.16	330/356	AECI/AMMO	Base Case	115.09	NA	145.03	-0.09092	11.37	7.84%	$ 0.61	7.7644	42.112	-	7.7644
SH Charging	J2425POI - ENON_TP 345 kV ckt 1	345	5.79	330/356	AECI/AMMO	Base Case	114.99	84.43	145.03	-0.09092	11.37	7.84%	$ 0.27	3.4161	18.528	-	3.4161

Table 46: J3200 NRIS Results

Model	Monitored Facility	Line Length (miles)	Voltage (kV)	Rating (MVA)	Areas	Areas Name	Contingency	Final AC %Loading	Base FG Flow	Top30 Impact	Dfax	MW Impact (MW)	Cumulative MW Impact (MW)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Cost Allocation (%)	Cost Estimate ($MM)
NRIS	JORD - 4W_FRFT_E 138 kV ckt 1	6.45	138	478	357	AMIL	P12:345:AMIL::MTVERNON-W:WESTFRANKFORT-E:4561	124.85	16.89	579.88	5.46%	13.66	395.26	2.3865	10.965	0.03455953	0.0825

Table 47: J3216 ERIS Results

Model	Monitored Facility	kV	Line Length (miles)	Areas	Areas Name	Contingency	Final AC %Loading	Bench Final AC %Loading	Cumulative MW Impact (Harmers	Dfax	MW Impact (MW)	Cost Allocation (%)	Cost Allocation ($MM)	Reconductor Cost ($MM)	Rebuild Cost ($MM)	Replacement Cost ($MM)	Reinforcement Cost ($MM)
Summer Peak	MCLEAN - PONTIAC 345 kV ckt 1	345	10.39	222	CE	P12:COMED345:L8002::S:SRT:A_Dup1	120.64	73.04	134.03	0.21943	67.01	50.00%	$ 3.06	6.1301	33.248	-	6.1301
Summer Peak	DRESDEN - AD1-133 TAP 345 kV ckt 1	345	20.14	222	CE	Base Case	115.88	82.12	154.12	0.09138	27.91	18.11%	$ 2.15	11.8826	64.448	-	11.8826
Summer Peak	LORETTO - AD1-100 TAP 345 kV ckt 1	345	20	222	CE	Base Case	104.42	62.25	407.06	0.12572	38.39	9.43%	$ 1.11	11.8	64	-	11.8
Summer Peak	LORETTO - PONTIAC 345 kV ckt 1	345	11.47	222	CE	Base Case	102.11	59.9	407.06	0.12572	38.39	9.43%	$ 0.64	6.7673	36.704	-	6.7673

Appendix F: SOO Green HVDC Line Results

Table 1: SOO Green HVDC Line Summer Peak Results

Model	Monitored Facility	kV	Line Length (mi.)	Contingency Type	Contingency	Dfax	Impact (MW)	Reconductor Cost ($MM)	Replacement Cost ($MM)
Summer Peak	PLANO 3M xfmr 1 345/765 kV	345/765	-	Breaker	COMED_P4_167-45-BT5-6__	0.28648	582.9872	-	18
Summer Peak	PLANO 4M xfmr 1 345/765 kV	345/765	-	Breaker	COMED_P4_167-45-BT9-12_	0.26628	541.8831	-	18
Summer Peak	ELECT JCT - LOMBARD ckt 1 345 kV	345	17.64	Single	COMED_P2-1_111-L11120__	0.0841	171.1446	10.4	-

Table 2: SOO Green HVDC Line Light Load Results

Model	Monitored Facility	kV	Line Length (mi.)	Contingency Type	Contingency	Dfax	Impact (MW)	Reconductor Cost ($MM)	Replacement Cost ($MM)
Light Load	AF2-359 TAP - OLIVE ckt 1 345 kV	345	7.33	Single	AEP_P1-2_#695_1681	0.10328	210.1823	4.3	-
Light Load	WILTON 4M xfmr 1 345/765 kV	345/765	-	Breaker	COMED_P4_112-65-BT2-3__	0.15803	321.5897	-	18
Light Load	ALLEN – RPMONE ckt 1 345 kV	345	24.42	Breaker	AEP_P4_#7445_05MARYSV 765_B	0.07287	92.9067	14.4	-
Light Load	AD1-100 TAP - WILTON ckt 1 345 kV	345	18.8	Single	COMED_P1-2_765-L11216__-S	0.08586	174.7329	11.1	-
Light Load	WILTON 3M xfmr 1 345/765 kV	345/765	-	Breaker	COMED_P4_112-65-BT5-6__	0.15475	314.9259	-	18
Light Load	ST JOHN - GREEN_ACRE ckt 1 345 kV	345	0.16	Single	COMED_P1-2_765-L11215__-S	0.09304	189.3394	0.1	-
Light Load	STILLWELL - DUMONT ckt 1 345 kV	345	11.45	Single	COMED_P1-2_765-L11215__-S	0.14791	301	6.8	-
Light Load	UNIV PK N - AF2-359 TAP ckt 1 345 kV	345	65.92	Single	AEP_P1-2_#695_1681	0.10328	210.1823	38.9	-
Light Load	E FRANKFO - CRETE EC ckt 1 345 kV	345	12.68	Single	COMED_P1-2_765-L11215__-S	0.1301	264.7474	7.5	-
Light Load	ST JOHN - ST JOHN ckt 1 345 kV	345	6.78	Single	COMED_P1-2_765-L11215__-S	0.09304	189.3394	4.0	-
Light Load	BURNHAM - MUNSTER ckt 1 345 kV	345	8.82	Single	COMED_P1-2_765-L11215__-S	0.12338	251.0798	5.2	-
Light Load	GREENACRE - OLIVE ckt 1 345 kV	345	47.12	Single	AEP_P1-2_#695_1681	0.0843	171.5429	27.8	-
Light Load	AG1-410 TAP - MADDOX ckt 1 345 kV	345	4.17	Breaker	AEP_P4_#7445_05MARYSV 765_B	0.07287	85.6196	2.5	-
Light Load	PLANO 4M xfmr 1 345/765 kV	345/765	-	Breaker	COMED_P4_167-45-BT8-12_	0.30373	618.0942	-	18
Light Load	J1180 TAP - SULLIVAN ckt 1 345 kV	345	14.65	Breaker	AEP_P4_#3128_05EUGENE 345_A2	0.04681	62.2568	8.6	-
Light Load	RPMONE - AG1-410 TAP ckt 1 345 kV	345	8.59	Breaker	AEP_P4_#7445_05MARYSV 765_B	0.07287	92.9067	5.1	-

Light Load	GREEN_ACRE - GREENACRE ckt 1 345 kV	345	0.16	Single	AEP_P1-2_#695_1681	0.0843	171.5429	0.1	-
Light Load	PLANO 3M xfmr 1 345/765 kV	345/765	-	Single	COMED_P1-3_TR94_PLANO_R-S	0.23594	480.142	-	18
Light Load	BUNSONVILLE - EUGENE ckt 1 345 kV	345	11.51	Single	AEP_P1-2_#695_1681	0.06116	124.4633	6.8	-
Light Load	BURNHAM - SHEFFIELD ckt 1 345 kV	345	5.62	Single	COMED_P1-2_765-L11215__-S	0.09766	198.7339	3.3	-
Light Load	DUMONT - SORENS ckt 1 765 kV	765	91.2	Breaker	AEP_P4_#7334_05JEFRSO 765_A2	0.23949	487.3705	99.4	-
Light Load	AF1-090 TAP - 7PANA ckt 1 345 kV	345	6.9	Single	EXT_P12:345:AMIL::AUSTIN:PANA:1	0.03777	76.8656	4.1	-
Light Load	ELECT JCT - LOMBARD ckt 1 345 kV	345	17.64	Breaker	COMED_P4_012-45-BT5-6__	0.07391	150.4065	10.4	-
Light Load	E FRANKFO - UNIV PK N ckt 1 345 kV	345	5.41	Single	AEP_P1-2_#695_1681	0.10328	210.1823	3.2	-

Table 3: SOO Green HVDC Line Grid Resilience Results

Model	Monitored Facility	kV	Line Length (mi.)	Contingency Type	Contingency	Dfax	Impact (MW)	Reconductor Cost ($MM)	Replacement Cost ($MM)
Light Load	WILTON - DUMONT ckt 1 765 kV	765	90.75	Tower	COMED_P7-1_345-L6607__B-S_+_345-L97008_R-S-A	0.37893	771.1261	98.9	-

Appendix G: ESS Grid Resilience

Table 1: MISO Battery Storage Extreme Event Violations

Queue Position	Number of Extreme Events Seen	Contingencies
J2170	2	P7:345:AEP:I&M SULLIVAN - AEP DARWIN 345 P7:345:AEP:AEP DEQUINE - AEP MEADOW LAKE 345
J2552	2	P55:161:MEC:HILLS:8T1 8T2:DIFF P611:345-345:CE:CORDOVA:QUAD:1:QUAD:ESS H471:1
J2607	1	P71:138-345:AMIL::COFFEEN:ROXFORD:51:WOODRIVER:ROXFORD:02

Table 2: PJM Battery Storage Extreme Event Constraints List

	Number of Extreme Events	Contingency
AF2-441	2	ATSI-P7-1-TE-138-025T-A COMED_P7-1_345-L0103__R-S_+_345-L0104__B-S
AH2-204	5	COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-A COMED_P7-1_138-L11902_B-R_+_138-L19414GR-R-A COMED_P7-1_138-L11902_B-R_+_138-L19414GR-R-A COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-B COMED_P7-1_138-L11902_B-R_+_138-L17121_R-R-B
AH2-259	1	COMED_P7-1_345-L0103__R-S_+_345-L0104__B-S
AH2-290	2	COMED_P7-1_138-L11106_B-R_+_345-L15502_B-R-A COMED_P7-1_138-L11106_B-R_+_345-L15502_B-R-A
AH2-339	2	COMED_P7-1_345-L9806__R-S_+_345-L19601_B-S COMED_P7-1_138-L6101___-S_+_138-L98105_R-S-B

Appendix H: SOO Green Grid Resilience

Table 1: Soo Green Extreme Event Constraints List

	Number of Extreme Events	Contingency
AF1-200	1	COMED_P7-1_345-L6607__B-S_+_345-L97008_R-S-A