December 30, 2016

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C.  20426

Re:    PJM Interconnection, L.L.C., Docket No. ER17-718-000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act, 1 Part 35 of the rules and regulations of the Federal Energy Regulatory Commission (“Commission” or “FERC”), 2 PJM Interconnection, L.L.C. (“PJM”) concurrently 3 with Midcontinent Independent System Operator, Inc. (“MISO”) (collectively referred to herein as “RTOs” and individually as “RTO”) submit for filing proposed revisions to the MISO-PJM Joint Operating Agreement (“JOA”) 4 to create a new interregional transmission project type that facilitates the development of low cost, high value transmission

3 Although the RTOs propose identical amendments to the MISO-PJM Joint Operating Agreement, each RTO maintains its own version of the JOA in its respective e-Tariff database at the Commission. Accordingly, each RTO must separately file the proposed amendments. As a result, three filings are being submitted concurrently to the Commission to implement the proposed amendments: (1) the instant filing by PJM to propose amendments related to the Targeted Market Efficiency Project planning process; (2) a submission by MISO and the MISO Transmission Owners to implement the identical planning process amendments and associated interregional cost allocation provisions; and (3) a submission by the PJM Transmission Owners to implement interregional cost allocation amendments identical to those proposed by MISO and the MISO Transmission Owners under section 9.4.4.2.5 of the JOA. In addition, the PJM Transmission Owners, MISO and the MISO Transmission Owners will file separately proposed regional cost allocation methodologies for Targeted Market Efficiency Projects under their respective regional tariffs no later than 120 days after the date of this filing in order for the Commission to grant an effective date for all proposed revisions related to the implementation of Targeted Market Efficiency Projects no later than 180 days after the date of this filing, or June 28, 2017.
4 The formal name of the MISO-PJM JOA or JOA is the “Joint Operating Agreement Between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.” The MISO-PJM JOA is a FERC-filed rate schedule of both PJM and MISO. The MISO-PJM JOA is designated as PJM’s Rate Schedule No. 38 and is available on PJM’s website at http://www.pjm.com/media/documents/merged-tariffs/miso-joa.pdf and MISO’s Rate Schedule No. 5 and is available on MISO’s website at https://www.misoenergy.org/Library/Pages?RateSchedules.aspx.
projects (hereinafter referred to as “Targeted Market Efficiency Projects” or “TMEPs”) intended to reduce historical congestion on known Reciprocal Coordinated Flowgates along the MISO-PJM border to benefit customers and improve coordination between the RTOs. The proposed amendments also include provisions for cost allocation of these projects between the RTOs. PJM and MISO request an effective date consistent with the effective date of the regional allocation methodologies filed in support of this proposal, which are planned to be filed no more than 120 days after the date of this filing. Accordingly, MISO and PJM request an effective date for the proposed amendments no later than 180 days from the date of the instant filing, or no later than June 28, 2017.

The proposed amendments are designed to implement the Targeted Market Efficiency Project process, which is a streamlined process focused on relatively small, low cost, short lead-time projects intended to deliver “quick hit” solutions with a payback period of only four years. The process complements the existing JOA provisions for larger transmission projects by focusing on addressing known historical congestion with practical solutions for reducing congestion, while not unnecessarily limiting future opportunities for larger projects. These targeted projects address congested areas along the seam that have estimated costs that do not support a major construction project based on production cost. Instead, the proposed targeted approach identifies localized solutions, which the current JOA does not support. Unlike the Interregional Transmission Projects which are first identified through the RTOs’ respective

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5 See JOA § 2.2.54.
6 See supra at 1, n. 3.
7 The RTOs have collaborated in drafting their respective transmittal letters and submit (by separate filings being made contemporaneously) identical language to the MISO-PJM JOA regarding these revisions. .
8 Under the current Interregional Market Efficiency Project analysis, benefits are calculated using a complex present value benefits calculation. See JOA § 9.4.4.1.3.1.
regional processes, these projects are targeted at relieving congestion between MISO and PJM at designated flowgates under the MISO-PJM JOA and would not appear under each RTO’s regional process. For this reason, modifying the JOA process is the appropriate means for identification and resolution of this specific and narrow class of interregional projects.

The RTOs have identified five Targeted Market Efficiency Projects that, as a result of the MISO-PJM joint analyses detailed below, are eligible for recommendation to each RTO’s respective Board for approval upon Commission acceptance of these proposed revisions to the JOA. Collectively, these projects have expected benefits of approximately $100 million (at a total estimated installed cost of $17.25 million for the five projects) in avoided market-to-market congestion along the MISO-PJM border in the first four years after the projects are in service.

These proposed amendments were vetted with stakeholders and are rooted in Commission direction provided in the NIPSCO Order, as well as other Commission proceedings. This proposal has received widespread support among transmission owners and stakeholders at the Interregional Planning Stakeholder Advisory Committee (“IPSAC”).

I. BACKGROUND

PJM and MISO have engaged and continue to engage in efforts to improve interregional coordination along the PJM-MISO seam, including efforts to facilitate construction of interregional projects on the seam. The RTOs have undertaken these efforts in direct response to Commission concerns about interregional coordination along the PJM-MISO seam. Particularly,

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10 See e.g., Competitive Transmission Development Tech. Conf., Docket No. AD16-18-000 (administrative docket opened by the Commission to explore matters related to competitive transmission development programs and matters related to interregional transmission project development).
since the filing of the NIPSCO Complaint on September 11, 2013\textsuperscript{11} which raised concern about congestion costs and operating issues along the MISO-PJM border, the RTOs have made important modifications to the MISO-PJM JOA to enhance the interregional coordination process consistent with Order No. 1000\textsuperscript{12} and other Commission directives.\textsuperscript{13}

A. The RTOs’ Joint Planning Studies

In 2012 – 2014, MISO and PJM conducted a multi-year, long-term joint planning study ("2012 - 2014 Joint Study") focused on relieving future congestion on fifteen market-to-market flowgates showing congestion in the future-year production cost model simulations (2018, 2023 and 2028). Multiple "future scenario studies" involving a range of assumptions were modeled. Approximately 80 potential projects intended to relieve future congestion were evaluated under a multi-year, multi-scenario economic analysis and measured against the Cross Border Market Efficiency Project criteria specified in Article IX of the then-current MISO-PJM JOA. After exhaustive analyses of the approximately 80 projects considered in the 2012 – 2014 Joint JOA study of longer lead-time upgrades, only two projects passed the interregional screening metrics; however, those projects could not be pursued as Interregional Projects because regional criteria

\textsuperscript{11} Complaint of Northern Indiana Public Service Company, Docket No. EL13-88-000 (filed Sept. 11, 2013)("NIPSCO Complaint").


\textsuperscript{13} See supra at 4, note 11.
did not permit approval of projects below 345 kV or upgrades with installed costs estimated at less than $20 million.\textsuperscript{14}

**B. Quick Hit Study**

Informed by the results of the 2012 - 2014 Joint Study, the RTOs decided to explore whether a process could be developed to address historic congestion, as opposed to forward-looking congestion, under the planning models. In 2014 - 2015, the RTOs conducted a “Quick Hit” study to identify near-term, high value, interregional economic transmission projects to alleviate known cross-border constrained facilities. Under the Quick Hit study, the RTOs evaluated known historical constraints along the MISO-PJM border and identified transmission solutions required to mitigate real-time congestion across the MISO-PJM seam promptly.\textsuperscript{15} However, the RTOs had no mechanism under the MISO-PJM JOA with which to approve the Quick Hit projects. The then-current Cross Border Market Efficiency Project criteria (that included both the MISO-PJM interregional requirements, as well as the MISO and PJM regional requirements) included cost thresholds of $20 million, voltage thresholds of 345 kV, and relied on future-looking production cost models to show project benefits. A major difference between the Quick Hit process that was being developed and typical market congestion planning studies was the removal of a computationally intense, very time consuming, forward-looking production cost study process. While the RTOs typically use production cost models to project future

\textsuperscript{14} Details of all 80 projects were included in the IPSAC materials located on the PJM and MISO websites. See January 16, 2014 MISO-PJM IPSAC Presentation, at https://www.misoenergy.org/Library/Repository/Meeting\%20Material/Stakeholder/Workshops\%20and\%20Special\%20Meetings/2014/IPSAMISO%20Joint\%20Planning%20Study\%20Presentation.pdf.

benefits of economic projects, the Quick Hit study used historical Day-Ahead and Real-Time congestion to show planning needs. Additionally, many of the recurring historical congestion issues were not present in the RTOs’ production cost models, highlighting a gap in the identification of transmission planning issues.\footnote{The reference to “gap” throughout this filing refers to the differences between the actual system conditions under which we operate the system and the forecasted conditions used for forward-looking traditional planning studies over a long-range planning horizon. This gap occurs because the actual system conditions never exactly replicate the planned-for future system conditions. In addition, the differences are more pronounced along an interface where there are two separately operated systems. This proposal tries to narrow that gap by planning for facilities to address actual operating conditions.} Many of the upgrades identified by the Quick Hit study were relatively small in scope (in some cases, the estimated costs of the upgrades were below $5 million) and on lower voltage facilities (below 345 kV). The benefits of cross-border upgrades of this type along the MISO-PJM border are often at too granular a level to be seen in the future-looking production cost simulations that are run to support a Market Efficiency Project analysis. Also, as noted above, these smaller scale upgrades could not satisfy the Interregional Market Efficiency Project Criteria\footnote{JOA § 9.4.3.1.2 (i) and (iv).} under the MISO-PJM JOA because they were below the requisite estimated project cost threshold of $20 million and the 345 kV regional threshold required under the MISO Tariff.\footnote{See MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, Attachment FF, Section II.B (iii-iv) (defining requirements for Regionally Beneficial Projects) (“MISO Tariff”). See also Midcontinent Independent System Operator, Inc., Compliance Filing of MISO regarding NIPSCO Complaint, Docket No. ER16-1969-000 at 5 (Jun. 20, 2016) (proposed revisions to remove the voltage threshold and lower the cost threshold).}

Given the results of the Quick Hit study, PJM and MISO began to work with their stakeholders to design a process to complement the longer-term market efficiency analysis and address historical congestion on the PJM-MISO seam. The goal of these efforts was to identify a process for low cost, high value transmission projects (like the Quick Hit solutions) to be reviewed, approved and moved forward.
C. Targeted Market Efficiency Projects Criteria & Study

Due to the encouraging Quick Hit study results, the RTOs engaged in discussions that resulted in a new project type, Targeted Market Efficiency Projects. The Targeted Market Efficiency Project type is an enhancement to the existing Interregional Transmission Projects but, as noted previously, would not otherwise appear in a regional planning process given that by definition these projects are designed and analyzed to address the reduction of congestion across the designated flowgates identified under the JOA.

Recognizing this fact, the RTOs, working with their stakeholders and transmission owners in the IPSAC meetings, developed a study process to identify Targeted Market Efficiency Projects. Key study considerations to identify this new type of project were: (i) the study must be targeted at historical congestion on known Reciprocal Coordinated Flowgates; (ii) given the relatively small cost of such projects and their near term benefits, the study process by which to identify congestion and project benefits must be streamlined so as to avoid delays in implementation of such projects; and (iii) the upgrades must be relatively small, low cost, and short lead-time projects that could be readily implemented.\(^{19}\)

The RTOs’ intent was to develop a process that would identify projects using narrowly defined criteria qualifications to “fill the gap” left by the Interregional Market Efficiency Project process. Thus, in order for an upgrade to qualify as a Targeted Market Efficiency Project, the upgrade must meet the following criteria: (i) must be needed to address historical congestion on known Reciprocal Coordinated Flowgates; (ii) the estimated in-service date must be by the third summer peak season from the year in which the project is approved; (iii) the estimated installed

\(^{19}\) Intra-regional cost allocations for such projects were discussed through the RTOs’ respective stakeholder processes.
cost (in study year dollars) must be less than $20 million; (iv) the upgrade must relieve expected congestion based on historical and current conditions; (v) the upgrade must be recommended by the Joint Reliability Planning Committee (“JRPC”) as a Targeted Market Efficiency Project; and (vi) the final recommended projects must be approved by each respective RTO’s Board.\(^{20}\)

The RTOs conducted a Targeted Market Efficiency Project study during late 2015 and 2016 to identify potential Targeted Market Efficiency Project upgrades that met the above criteria. The final results of the study were presented at the October 28, 2016 IPSAC meeting.\(^{21}\)

PJM and MISO propose this additional enhanced process to complement the Order No. 1000 forward-looking study processes for Interregional Market Efficiency Projects already included in the MISO-PJM JOA. PJM and MISO propose to fill in the gap left by long-term market efficiency planning studies with a new project type to address easily resolvable, historical congestion with low cost, high value upgrades that can be implemented in short order.

In support of this proposal, PJM and MISO reviewed historical data with its stakeholders. Out of the 50 potential Reciprocal Coordinated Flowgates identified as having significant historical congestion, the RTOs found 13 potential Targeted Market Efficiency Project upgrades.\(^ {22}\) From those 13 potential upgrades, the RTOs identified five Targeted Market Efficiency Project upgrades costing an estimated $17.25 million to construct, which would address $57.8 million in historical congestion (2014 - 2015), resulting in approximately $100

\(^{20}\) JOA § 9.4.4.1.5 proposed.


million in Targeted Market Efficiency Project benefits over the first four years in-service.\textsuperscript{23} The RTOs are prepared to recommend these five Targeted Market Efficiency Project upgrades\textsuperscript{24} to their respective Boards upon acceptance of these proposed revisions together with the associated interregional and regional cost allocation methodologies referenced above.

\textbf{D. Stakeholder Process}

During the February 5, 2016 IPSAC meeting, PJM and MISO continued discussions with stakeholders about memorializing a study process in the JOA that would focus on addressing Targeted Market Efficiency Projects. During the stakeholder meetings, which continued through December 2, 2016, the concept of a Targeted Market Efficiency Project study process and cost allocation methodology was discussed extensively and included vetting the following topics: (i) comparing Targeted Market Efficiency Projects with longer term Interregional Market Efficiency Projects;\textsuperscript{25} (ii) evaluating two years of historical congestion data; (iii) developing a benefit-to-cost ratio (\textit{i.e.} a short payback period); (iv) presenting proposed JOA language for stakeholder review and feedback, including circulating a survey seeking stakeholder feedback on two key issues (\textit{i.e.} whether congestion hedges should be included in the benefit calculation and how many years of historical congestion should be considered);\textsuperscript{26} and (v) reviewing results of the


\textsuperscript{24}See Id. at Slide 10.


Targeted Market Efficiency Study and the RTOs’ proposed recommended Targeted Market Efficiency Projects.\(^{27}\)

II. DESCRIPTION OF PROPOSED REVISIONS TO THE MISO-PJM JOA

PJM and MISO propose to modify Article IX of the MISO-PJM JOA, sections 9.3 and 9.4, to add a study process that addresses persistent historic congestion on known Reciprocal Coordinated Flowgates\(^{28}\) that exist today along the MISO-PJM border and, based on operational market results occurring on the border, are expected to persist into the foreseeable future.\(^{29}\)

Fundamentally, the Targeted Market Efficiency Project study process is intended to address the gaps between real-time market operations and forward-looking traditional planning studies.

These low cost, cost-effective upgrades complement longer-term studies of larger, more expensive and typically lower benefit-to-cost ratio projects under a longer-term Coordinated System Plan study consistent with section 9.3.7.2 of the JOA. The challenge is to get the projects in place to address issues that have occurred and are continuing to occur in the near future.

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\(^{27}\) See supra at 8, n.21.

\(^{28}\) Currently, there are approximately 300 Reciprocal Coordinated Flowgates the RTOs actively monitor along the MISO-PJM border. This year’s Targeted Market Efficiency Project study found 50 of the Reciprocal Coordinated Flowgates to have $1 million or more in historical congestion in 2015. See March 7, 2016 MISO PJM IPSAC Presentation, at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/IPSAC/20160307%20MISO%20PJM%20IPSAC/20160307%20MISO%20PJM%20IPSAC%20Presentation.pdf.

\(^{29}\) As agreed upon, the RTOs will verify the expectation that the congestion on the historical Reciprocal Coordinated Flowgates is expected to persist into the foreseeable future. This analysis will evaluate whether the planned or forced transmission outages are the cause of the congestion. If yes, the flowgate will not be considered in the Targeted Market Efficiency Project study, as it would be expected to be alleviated after completion of the outage. If no, the RTOs will evaluate whether the congestion is expected to be mitigated by a planned upgrade. If yes, the flowgate will not be included in the Targeted Market Efficiency Project study. If no, the flowgate will be included in the study to determine if a Targeted Market Efficiency Project is the most efficient or cost effective solution to mitigate the congestion. In order to make that determination, the RTOs will evaluate whether the solution causes more congestion on adjacent flowgates. If yes, the RTOs will not recommend the Targeted Market Efficiency Project and will instead consider it for evaluation under the longer-term Market Efficiency Project analysis.
Using operational expertise and analysis, PJM and MISO have identified real-time congestion issues on known Reciprocal Coordinated Flowgates that likely will continue to persist into the foreseeable future because there are no projects currently planned that are expected to mitigate these issues. The Targeted Market Efficiency Project process is a standalone, innovative concept developed in collaboration with stakeholders who have asked that these issues be addressed.\(^{30}\)

A. The Proposal Appropriately Limits Application of the Targeted Market Efficiency Project Process – JOA Section 9.4.4.1.5

The Targeted Market Efficiency Project process is intended to facilitate the development of small interregional projects that can be built quickly to reduce real-time congestion on known Reciprocal Coordinated Flowgates in order to realize the benefits of reduced congestion costs as compared to the upgrade’s estimated costs. In order to effectuate the purpose of this proposal, the RTOs together with their stakeholders agreed upon limits to the qualification of a Targeted Market Efficiency Project. Specifically, section 9.4.4.1.5 provides that in order for an upgrade to qualify as a Targeted Market Efficiency Project, it must:

(i) Be evaluated as part of a Coordinated System Plan or joint study process under section 9.3.7.2(c) of the JOA and demonstrate an expectation that the upgrade will provide substantial relief of identified history market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project is approved;

(iii) Have estimated installed cost (in study year dollars) less than $20 million;

(iv) Be determined to have expected future congestion relief\(^{31}\) due to the upgrade of the targeted Reciprocal Coordinated Flowgate\(^{32}\) that is equal to the sum of annual

\(^{30}\) See, e.g., NIPSCO Complaint.

\(^{31}\) Proposed § 9.4.4.1.5(iv)(a) of the MISO-PJM JOA provides that expected future congestion relief is the amount of a Reciprocal Coordinated Flowgate’s anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis.
congestion\textsuperscript{33} over the four year period following the study year that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs in study year dollars; and

(v) Be recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO’s Board.

The criteria is focused on developing a streamlined process that will allow the RTOs to propose projects to promptly address historic and near term congestion with small, low cost, short lead-time upgrades. Consistent with such principles, the RTOs propose a four-year payback period. The four-year payback period is appropriate for the specific, limited criteria of Targeted Market Efficiency Projects. Specifically, Targeted Market Efficiency Projects are intended to address historical congestion that, if not addressed, is expected to persist into the foreseeable future and is not expected to be substantially alleviated by system changes planned in the five-year planning horizon. By comparing the total installed cost of a project in current year dollars with the benefits (value of eliminating the historical congestion over a four year period), it was determined using the project criteria that the average benefits to cost ratio represented a conservative number that demonstrated significant value to affected loads. Applying a four-year payback to the five projects recommended to the IPSAC under the Targeted Market Efficiency Project study results in a benefit-to-cost ratio for each of the five projects that is significantly higher than the 1.25 benefit-to-cost ratio used for Market Efficiency Project evaluations.

\textsuperscript{32} Proposed §§ 9.4.4.1.5(iv)(b) and (c) of the MISO-PJM JOA further define historical congestion as it is quantified under each RTO’s respective tariff. For example, historical congestion in PJM is quantified in accordance with PJM’s Open Access Transmission Tariff (“PJM Tariff”) at Attachment K-Appendix, § 5.1 to include charges associated with Day-Ahead and Real-Time market congestion for Market Buyers, Generating Market Buyers and Market Sellers. Historical congestion in MISO is quantified in accordance with the MISO Tariff, §§ 39.2.9 Day-Ahead Energy and Operating Reserve Market Process and § 40.2.15 Real-Time Energy and Operating Reserve Market Process to include charges associated with Day-Ahead and Real-Time market congestion for both load and generator busses.

\textsuperscript{33} Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study period. See JOA § 9.4.4.1.5(iv)(d) proposed.
B. Proposed Method for Determining Benefits to Be Derived From a Targeted Market Efficiency Project – JOA Section 9.4.4.1.5.1

The benefits derived from a Targeted Market Efficiency Project are a critical component of this proposal. The Targeted Market Efficiency Project benefits are based on the RTOs’ actual results of market operations along the MISO-PJM border that rely upon a complex, specific and very unique congestion coordination protocol that is beyond the modeling capabilities of current long-term planning simulation software used in determining the benefits of an Interregional Market Efficiency Project. This unique modeling challenge, which manifests particularly at the operational boundaries of the electric system, creates heightened planning challenges, especially for lower voltage issues near electrical borders.

After consideration of input from stakeholders, the RTOs propose to jointly evaluate the benefits to the combined markets and each RTO for each potential Targeted Market Efficiency Project using the following process set forth in section 9.4.4.1.5.1 of the JOA:

(i) With input from the IPSAC, determine the estimated total installed project capital cost in study year dollars; and

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars where the expected future congestion relief is the sum of each RTO’s expected congestion relief, adjusted by market-to-market settlement payments.

The project benefits are based on historical congestion on known congested Reciprocal Coordinated Flowgates, and the RTOs will select the project that most efficiently eliminates the congestion.

Using a simple benefit-to-cost metric, the following table illustrates the high value expected to be achieved from Targeted Market Efficiency Projects. Included in the table are the

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34 See JOA § 9.4.4.1.3.1.
five Targeted Market Efficiency Project upgrades presented to the IPSAC. The first four columns labeled “TMEP” illustrate, in succession: (i) the average historical congestion on the five Reciprocal Coordinated Flowgates; (ii) the projected benefit calculated as four times the historical congestion; (iii) the estimated installed cost of the Targeted Market Efficiency Project (in study year dollars); and (iv) the calculated benefit-to-cost ratio for each potential project. The four columns on the right side of the table show the calculation of the project benefit-to-cost ratio if a comparable, more complex 15 year present value calculation is performed consistent with the Interregional Market Efficiency Projects identified under a long-term study process. Because the Targeted Market Efficiency Project metric approximates the calculation that would be produced by the more complex Market Efficiency Project metric but is consistently somewhat lower, this table demonstrates that the Targeted Market Efficiency Project metric is reasonable and based on high value expectations.

<table>
<thead>
<tr>
<th>Project Location</th>
<th>Average Historical Congestion* (Million $)</th>
<th>TMEP Benefit (Million $) (4 x average)</th>
<th>TMEP Cost (Million $)</th>
<th>TMEP Benefit/Cost (B/C)</th>
<th>Present Value of 15 Year Benefit</th>
<th>Equivalent Levelized Annual Cost</th>
<th>Present Value of 15 Year Levelized</th>
<th>15 Year B/C</th>
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<td>17.0</td>
<td>0.8</td>
<td>7.5</td>
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</table>

*Average of past two years, historical congestion minus outage driven congestion

**Assumptions:**
- All projects go in service the third summer out: 2019
- Present value calculation uses 15 years of benefits from the current year (2016)
- Present value calculation uses average historical congestion applied to all years; inflated to that year’s dollars
- Present value calculation uses Inflation: 2%
- Present value calculation uses Carrying Charge: 16.7%
- Present value calculation uses Discount Rate: 7.78%

**Conclusion:**
B/C calculated over 15 years with these assumptions will always be ~1.5 times greater than the TMEP B/C. Thus, the TMEP metric ensures high value projects.
Generally, the most efficient, quick and cost effective means to address congestion will be to upgrade existing transmission facilities that are acting to limit parts of the transmission system to less than their maximum conductor ratings. Consistent with this understanding, Targeted Market Efficiency Project upgrades will be limited by the requirement that they must be able to be in service by the third summer peak period. Realistically, only upgrades that are limited in scope can be in service within such a short timeframe. This point is illustrated by the RTOs’ recent analyses: all five Targeted Market Efficiency Projects being recommended, arising from the RTOs’ Targeted Market Efficiency Project study, are upgrades to existing facilities, as were the two projects that came out of the Quick Hit study in the second half of 2015.

C. **The Proposed Targeted Market Efficiency Project Study Process – JOA Section 9.3.7.2(b)(iii)**

The Coordinated System Plan Study process detailed under section 9.3.7.2(b)(iii) of the JOA allows for the formation of an *ad hoc* study group to perform targeted studies to, among other things, ensure the coordinated efficiency of the RTOs’ systems. Proposed section 9.3.7.2(c) provides that section 9.3.7.2(b)(iii) may include a Targeted Market Efficiency Project study to “evaluate, analyze and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border.” To qualify, the identified historical market-to-market congestion must be “expected to persist and [ ] not expected to be substantially alleviated by system changes planned in the five

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year planning horizon.” Additionally, section 9.3.7.2(c) qualifies that the RTOs will identify historical congestion on Reciprocal Coordinated Flowgates known to be caused by outages and will not consider such congestion for purposes of a Targeted Market Efficiency Project study or will determine a proportionally reduced amount of congestion associated with that Reciprocal Coordinated Flowgate, as appropriate. Finally, all Targeted Market Efficiency Project studies initiated under a Coordinated Plan Study will be conducted consistent with section 9.3.7.2 except as provided for under proposed subsections 9.3.7.2(c)(i) through (v), which are necessary to recognize the unique characteristics of this study process that are driven by the temporal limitations of the benefit-to-cost ratio that justifies the upgrades. Thus, section 9.3.7.2(c)(v) provides that:

Solely for the purpose of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTO Boards as described in section 9.3.7.2(b)(xi).

D. The Proposal Is Just and Reasonable

Under Order No. 1000, the developer of an interregional transmission project must first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. According to the MISO-PJM JOA, the submission of the interregional transmission project in each regional transmission planning process will trigger the procedure under which the RTOs, acting through

37 See JOA § 9.3.7.2(c) proposed.
38 See JOA § 9.3.7.2(c)(v) proposed.
39 Order No. 1000 at PP 393, 396.
their regional transmission planning process, will jointly evaluate the proposed transmission project.40

As noted above, this filing proposes a standalone process for Targeted Market Efficiency Projects that is intended to complement, not displace, a longer-term Coordinated System Plan study for interregional reliability or market efficiency projects. Targeted Market Efficiency Projects will provide for high value, low cost upgrades that are small in size and must be placed into service within three summer peak periods to resolve historical market-to-market congestion expected to persist in the near term and not expected to be relieved by system changes planned in the five-year planning horizon. As noted above, the nature of these projects and their drivers, arising from congestion at the designated flowgates under the MISO-PJM JOA, dictate that these projects address issues that would not otherwise appear in the regional processes. As a result, the requirement of Order No. 1000 that projects must first be identified in the regional processes before being submitted for consideration in the interregional processes41 is inapposite given the specific nature of these projects and the drivers of these projects.

Nonetheless, consistent with the interregional transmission coordination requirements of Order No. 1000, this proposal satisfies the four elements characteristic of interregional coordination: (i) coordination; (ii) evaluation; (iii) data exchange; and (iv) transparency.42 Specifically, the RTOs demonstrated through this process their commitment to coordinate and

40 See JOA § 9.3.1.2(b)(vii)(e).
41 Order No. 1000 at P 397. Under Order No. 1000, the Commission left it to the transmission planning regions “adequate discretion to allow for the development and implementation of interregional transmission coordination procedures that suit the needs of the neighboring transmission planning regions . . . .” In addition, the Commission expressed hesitation to provide further guidance on how RTOs should develop and implement interregional transmission coordination procedures as such guidance could inadvertently impose restrictions that are not appropriate for a transmission planning region. Id.
42 Order No. 1000 at P 394.
share not only the results of their respective region’s regional transmission plan but to identify possible issues along the MISO-PJM seam not identified through the reliability and market efficiency processes required for compliance with the Order No. 1000 interregional coordination process. To that end, the RTOs are proposing to improve upon their existing interregional coordination processes by identifying and jointly evaluating through the IPSAC possible Targeted Market Efficiency Project upgrades that more efficiently or cost-effectively address real-time congestion along the MISO-PJM border. As evidenced in the IPSAC presentations, the joint evaluation of possible Targeted Market Efficiency Projects included sharing of information and identifying potential solutions to address those needs.

The criteria qualifications for Targeted Market Efficiency Projects provide for a discrete and clearly-defined category of high value, low cost upgrades that must be placed into service within three summer peak periods to resolve historical market-to-market congestion expected to persist in the near term and not expected to be relieved by system changes planned in the five-year planning horizon. Additionally, this proposal offers a reasonable framework that details the study process to be used to identify Targeted Market Efficiency Projects and the method by which each RTO may determine the project benefits to each RTO.43 The RTOs believe this proposal allows for a determination that is sufficiently detailed for stakeholders to understand why a particular Targeted Market Efficiency Project was recommended or not recommended for approval by each RTO’s respective Board for purposes of cost allocation.44

43 See JOA § 9.4.4.1.5.1 proposed.

44 Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328; Order No. 1000-A, 139 FERC ¶ 61,132 at P 267.
III. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to, and the parties request the Secretary to include on the official service list, the following:

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IV. CONTENTS OF THIS FILING

The following is a list of documents submitted with this filing:

1. This transmittal letter;
2. Attachment A – Revised JOA effective no later than 180 days from the date of the filing (in redlined form); and
3. Attachment B – Revised JOA effective no later than 180 days from the date of the filing (in clean form).

V. EFFECTIVE DATE

PJM and MISO request an effective date consistent with the effective date of the regional allocation methodologies filed in support of this proposal, which are planned to be submitted no more than 120 days after the date of this filing. Accordingly, PJM and MISO request that the effective date for the amendments included with the instant filing be granted an effective date no later than 180 days after the date of this filing, or no later than June 28, 2017. To the extent such an effective date requires waiver of any of the Commission regulations, PJM and MISO respectfully request such waiver from the Commission.
VI. NOTICE AND SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission’s regulations,\(^{45}\) PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: [http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx](http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx) with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region\(^ {46}\) alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC’s eLibrary website located at the following link: [http://www.ferc.gov/docs-filing/elibrary.asp](http://www.ferc.gov/docs-filing/elibrary.asp) in accordance with the Commission’s regulations and Order No. 714.

VII. CONCLUSION

PJM and MISO respectfully request that the Commission accept the proposed revisions to the JOA to include this standalone, innovative concept developed in collaboration with stakeholders to create a new interregional transmission project type that facilitates the

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\(^{45}\) See 18 C.F.R §§ 35.2(e) and 385.2010(f)(3) (2016).

\(^{46}\) PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.
development of low cost, high value transmission projects intended to reduce historical congestion on known Reciprocal Coordinated Flowgates along the MISO-PJM border to benefit customers and improve coordination between the RTOs.

Respectfully submitted,

By:   

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On behalf of PJM Interconnection, L.L.C.

Dated: December 30, 2016
Attachment A

Revisions to the PJM – MISO Joint Operating Agreement

(Marked / Redline Format)
9.3 **Coordinated System Planning.**
The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 **Single Party Planning.**
Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

9.3.2 **Coordinated System Plan.**
The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.7. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.
9.3.3 **Analysis of Interconnection Requests.**

In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for coordination of interconnection studies and Network Upgrades *is detailed below*:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party’s relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The *coordinated interconnection studies* will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party.

(i) *The transmission reinforcement and the study criteria used in the coordinated interconnection studies will conform to and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and the Parties’ respective Tariffs.*

(ii) *The PJM and PJM transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the PJM transmission system when PJM evaluates the impact of MISO generation on PJM transmission facilities.*

(iii) *The MISO and MISO transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact of PJM generation on MISO transmission facilities.*

(iv) *The identification of all impacts on the Parties’ transmission systems shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcements.*

(v) If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.
The Parties will strive to minimize the costs associated with the coordinated study process.

(d) During the course of its interconnection studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. These potential impacts shall be included in the PJM System Impact Study report along with any information regarding the validity of these impacts and any transmission system reinforcements received from MISO and the MISO transmission owners.

(e) Following issuance of the PJM Feasibility Study report and after the Interconnection Customer executes the PJM System Impact Study Agreement, PJM shall forward to MISO, at a minimum of twice per year (April 15 and October 15), information necessary for MISO and the MISO transmission owners to study the impact of the PJM Interconnection Request(s) on the MISO transmission system. MISO and the MISO transmission owners shall study the impact(s) of the PJM Interconnection Request(s) on the MISO transmission system and provide draft results to PJM by:

(i) March 1 for PJM Interconnection Request(s) provided to MISO on or before October 15 of the previous year; and

(ii) September 1 for PJM Interconnection Request(s) provided to MISO on or before April 15 of the same year.

(f) During the determination of reinforcements for an Interconnection Request that are required to mitigate MISO constraint(s), PJM and MISO may identify other planned non-MISO reinforcement(s) that may alleviate such constraint(s) inside the MISO region. Under such circumstances, any PJM interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. MISO shall determine the necessary injection limits associated with the PJM Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through MISO’s affected system analysis are inservice.

(g) During the course of MISO’s interconnection studies, MISO shall monitor the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. Those potential impacts shall be included in the MISO System Impact Study report along with any information regarding the validity of these impacts and possible mitigation received from PJM and the PJM transmission owners.

(h) Prior to commencing the MISO Definitive Planning Phase (“DPP”) study, MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) on the PJM
transmission system. For the prescribed times when MISO provides this information to PJM, January 1 and July 1, PJM and the PJM transmission owners shall study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the draft results to MISO by:

(i) March 31 for requests submitted to PJM on or before January 7 of the same year; and

(ii) September 29 for requests submitted to PJM on or before July 7 of the same year.

(i) During the determination of reinforcements for an Interconnection Request that are required to mitigate PJM constraint(s), PJM and MISO may identify other planned non-PJM reinforcement(s) that may alleviate a constraint(s) inside the PJM region. Under such circumstances, any MISO interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. PJM shall determine the necessary injection limits associated with the MISO Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through PJM’s affected system analysis are in-service.

(j) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party’s Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate Facilities Study agreement as required under the impacted Party’s OATT.

(k) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(l) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(m) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(n) The Interconnection Customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the
appropriate Facilities Study Agreement as required under the impacted Party’s Tariff.

(o) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(p) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

9.3.4 **Analysis of Long-Term Firm Transmission Service Requests.**

In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party’s business practices manuals, which will determine the potential impact on each Party’s system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop
screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate facilities study agreement as required under the impacted Party’s OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.
9.3.5 Analysis of Incremental Auction Revenue Rights Requests.
The Parties will coordinate, as deemed appropriate, the conduct of any studies in response to a request for Incremental Auction Revenue Rights (“Incremental ARRs”) (“Incremental ARR Request”) made under one Party’s tariff to determine its impact on the other Party’s system. Results of such coordinated studies will be included in the impacts reported to the customer requesting Incremental ARRs as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) The Parties will coordinate the base Firm Flow Entitlement values associated with the Coordinated Flowgates that may be impacted by the Incremental ARR Request.

(b) Upon receipt of an Incremental ARR Request or the review of studies related to the evaluation of such request, the Party receiving the Incremental ARR Request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the Incremental ARR Request will notify the other Party and convey the information provided in the request in addition to but not limited to the list of impacted constrained facilities.

(c) During the System Impact Study, the potentially impacted Party may participate in the coordinated study by providing input to the studies to be performed by the Party receiving the Incremental ARR Request. The potentially impacted Party shall determine the Network Upgrades, if any, needed to mitigate constraints on identified impacted facilities. The Parties shall coordinate to ensure any proposed Network Upgrades maintain the reliability of each Party’s transmission system.

(d) Any coordinated System Impact Studies will be performed in accordance with the mutually agreed upon study timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement in accordance with applicable tariff provisions.

(e) During the Facilities Study, the potentially impacted Party may conduct its own Facilities Study as a part of Facilities Study being conducted by the Party that received the Incremental ARR request. The study cost estimates indicated in the Facility Study Agreement between the Party receiving the request and the Incremental ARR customer will reflect the costs and the associated roles of the study participants, including the potentially impacted Party. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.
(f) The Party receiving the Incremental ARR Request shall collect from the Incremental ARR customer, and forward to the potentially impacted Party, the agreed upon payments associated with the performance of such studies.

(g) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted Party, the Party receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the Incremental ARR customer.

(h) The construction of such Network Upgrades will be subject to the terms of the potentially impacted Party’s tariff, the agreement among owners transferring functional control of transmission facilities to the control of the potentially impacted Party, and applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, the Incremental ARR will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

\[\text{\small \textsuperscript{1} Infra (b).}\]
9.3.6 Analysis of Generator Deactivations (retirements and suspensions).

(a) The Party ("Noticed Party") receiving a new request from a generation owner to retire, deactivate, or mothball (or suspend operations as defined under the MISO Tariff) its generation unit will notify the other Party of such deactivation request no later than five (5) business days after receipt of the notice by the Noticed Party. The other Party ("Other Party") will determine if any study is required to evaluate potential impacts to its system due to the proposed generator deactivation in the Noticed Party’s system. Any studies required due to a notice to deactivate (retire or suspend operations as defined under the MISO Tariff) will be performed under each Party’s respective Tariff. Each Party’s regional study results will be documented and provided to the other Party for informational purposes only.

(b) Both Parties will share all information necessary to evaluate potential impacts to their respective systems due to the notice. Such coordination shall provide for:

(i) Exchange of current power flow modeling data as necessary for the study and coordination of generator deactivations (retirements and suspensions). This will include the associated update of the other Party’s generator availability, contingency elements, monitoring elements data, and other data as may be required.

(ii) Coordination by the Parties to align the assumptions of any analyses during development of the scope of any required studies. The scope design will include, as appropriate, evaluation of the transmission system against the criteria applicable to each Party for such studies.

(c) Following the exchange of information pursuant to section 9.3.6(b), the Other Party will conduct screening and evaluation of projects needed to mitigate identified impacts on its system. The Other Party will use reasonable efforts to perform an initial assessment and provide an indication of the impacts on its system to the Noticed Party within 65 days of receipt of the notice from the Noticed Party. The Other Party will provide a list of potential system reinforcements required on its system and estimated time for completion of those system reinforcements to the Noticed Party as soon as they are available.

(d) Each Party will be responsible for any regional Network Upgrades or other mitigation required on their respective system as a result of a request to deactivate (retirement or suspension).
(e) Any impact(s) on the Other Party’s system identified in the analysis will not be used to determine the need to retain the generator requesting to deactivate.

(f) The identification of Network Upgrades required for generator deactivation (retirement or suspension) in the Other Party’s system may require coordination through the JRPC. The Parties will endeavor to make such information available to the JRPC in a timely manner following publication of information through the Parties’ regional processes. Additional coordination, as may be needed, will be conducted pursuant to the Coordinated System Plan study process as mutually agreed to be the Parties in accordance with the provisions of Section 9.3.7.

(i) The JRPC will incorporate any needed regional upgrades that may be identified by the generator deactivation studies coordinated pursuant to this section 9.3.6 into the annual review processes of Section 9.3.7 for the purpose of determining if there is a more efficient or cost effective Interregional Reliability Project that may replace one or more of the identified regional Network Upgrades required for the generator deactivation.

(ii) The JRPC will consider the results of the deactivation analyses forwarded to the committee at the next scheduled JRPC meeting or within 30 days of receipt of the completed study information from both Parties. Depending on the timing of the receipt of the study information, the JRPC will determine the most appropriate process for including the regional deactivation results into the development of the Coordinated System Plan. Such process will include IPSAC review according to the Coordinated System Plan process of Section 9.3.7.

Throughout the interregional review process any confidentiality provisions of the Parties Tariff’s will be respected. Critical identified Interregional Reliability Projects for which the need to begin development is urgent will be presented to the Parties’ Boards for approval as soon as possible after identification through the Coordinated System Plan study process. Other identified Interregional Reliability Projects presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade.
9.3.7 Development of the Coordinated System Plan.

9.3.7.1

Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party’s plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to the integration described in the preceding part (a); and

(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.7.2

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.7.2.a; and 2) Coordinated System Plan study described in Section 9.3.7.2.b.

(a) Determine the Need for a Coordinated System Plan Study.

(i) On an annual basis, beginning in the fourth quarter of each calendar year and continuing through the first quarter of the following calendar year, the Parties shall perform an annual evaluation of transmission issues identified by each Party including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party’s regional planning cycles.
The JRPC’s annual review of transmission issues shall include the following steps:

a. Exchange of the following information during the fourth quarter of each calendar year:

i. Regional issues and newly approved regional projects located near the interface or expected to impact the adjacent region;

ii. Newly identified regional transmission issues for which there is no proposed solution;

iii. Interconnection requests under coordination by the Parties located near the interface or expected to impact the adjacent region;

iv. Market-to-market historical flowgate congestion between the Parties.

b. Joint review by the Parties of regional issues and solutions in January of each calendar year;

c. Receipt of Third Party issues in the first quarter of each calendar year;

d. Review of regional issues with input from stakeholders at the IPSAC meeting conducted during the first quarter of each calendar year; and

e. Decision by the JRPC on whether or not to conduct a Coordinated System Plan study.

The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to be held in the first quarter of each year to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting for consideration by the IPSAC and JRPC.

Within 45 days following the annual issues evaluation meeting with IPSAC in the first quarter of the calendar year, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (1) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (2) if after two consecutive years in which a Coordinated System Plan study has not been
performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study within five business days of the JRPC’s decision.

(v) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study and identify whether it is a targeted study as defined in this Section at (vi) or a more complex, two-year cycle study as defined in this Section at (vii).

(vi) A Coordinated System Plan study may include targeted studies of particular areas, needs or potential expansions to ensure that the coordination of the reliability and efficiency of the Parties’ transmission systems will be conducted during the first half of the calendar year. In years when the Coordinated System Plan study includes only targeted studies as defined herein, they may be conducted at any time during the calendar year but will be targeted for completion within the calendar year in which they are identified.

(vii) A Coordinated System Plan study may include more complex, longer duration studies involving joint model development that addresses reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

(viii) When a Coordinated System Plan study is determined to be necessary by the JRPC, the specific study process steps will depend on the type and scope of the study. The JRPC shall provide the timely, specific deadlines for each step in the Coordinated System Plan study in a timely fashion following the JRPC’s decision to initiate such study.

(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include
evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment at an IPSAC meeting scheduled no later than 30 days after the decision to conduct a Coordinated System Plan study.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented. Targeted studies will utilize the best available regional models for transmission and market efficiency analysis.

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party’s criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.7.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities
as appropriate when different regional assumptions must be accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) When Coordinated System Plan studies are undertaken pursuant to a two-year study cycle defined in this Section at (a)(vii), the following schedule will be followed unless otherwise mutually agreed to be the Parties.

a. Parties will provide updated identification of regional issues identified in this Section at (a) in the first year of the two-year cycle from June through September.

b. Regional models will be made available to the IPSAC for stakeholder review and comment in the first year of the two-year cycle from June through September.

c. Stakeholder Interregional Project proposals, satisfying applicable regional and interregional requirements, will be accepted by PJM in its proposal windows for Long-lead Projects and Economic-based Enhancements or Expansions as detailed in Schedule 6 of the PJM Amended and Restated Operating Agreement.

d. Stakeholder identification of Interregional Project proposals satisfying the applicable regional and interregional requirements will be accepted in the MISO regional process typically between January through March of the second year of the two-year cycle.

e. The Parties will evaluate each project proposal in its regional process during the second year of the two-year cycle to determine if a project is eligible for inclusion in the respective regional plans. An Interregional Project must be included in each Party’s regional plan to become an approved Interregional Project. The Parties shall target the end of the second year of the two-year cycle to include an approved Interregional Project.
(viii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.4.1.

(ix) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses. After the conclusion of the Coordinated System Plan study, any project included in the Coordinated System Plan and designated for interregional cost allocation, if not already engaged in the regional review process, will be submitted to the regional processes for review according to Section 9.3.7.2(b)(x).

(x) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.4.1. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report. The JRPC shall provide the Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.

(xi) The JRPC’s recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform
the IPSAC of the outcome of each Party’s review of the recommended Interregional Projects.

(c) Targeted Market Efficiency Project Study

The Coordinated System Plan study may include a Targeted Market Efficiency Project study consistent with Section 9.3.7.2(b)(ii). The Targeted Market Efficiency Project study will evaluate, analyze, and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border. Identified issues under this section will be expected to persist and are not expected to be substantially alleviated by system changes planned in the five (5) year planning horizon. Identification of issues will include, but not be limited to, the RTO’s determination, based on historical operational information, of any historical flowgate congestion known to be caused by outage conditions. The RTOs will not consider for purposes of a Targeted Market Efficiency Project study, historical congestion on a Reciprocal Coordinated Flowgate caused by outages or will determine a proportionally reduced amount of congestion associated with that flowgate, as appropriate. Any Targeted Market Efficiency Project study initiated by the JRPC under this section will be conducted under the process defined for a Coordinated System Plan study, except as modified by this section and the following subsections.

(i) Issues identified in the Targeted Market Efficiency Project study will be reviewed to determine the cause of the market issues, including: (a) the specific limiting elements, (b) verification of the ratings of the limiting elements, (c) whether approved, planned system changes may alleviate the issue, (d) whether outages contribute to all or a portion of the historical congestion, (e) estimates of the cost of upgrading the limiting elements, and (f) whether upgrades to the limiting elements could substantially relieve the constraints;

(ii) Using the results of the review under subsection (i) and the applicable criteria of Section 9.4, the JRPC will post results of the analysis for input from the IPSAC and will solicit proposals for Targeted Market Efficiency Projects that meet the criteria of Sections 9.3.7.2(c) and 9.4 applicable to a Targeted Market Efficiency Project;

(iii) The JRPC will determine the list of limiting element upgrades and Targeted Market Efficiency Project proposals to analyze the benefits to PJM and MISO for presentation to and input from the IPSAC.
(iv) Based on the analysis and stakeholder process conducted consistent with Sections 9.3.7.2(c) and 9.4, the JRPC will determine any Targeted Market Efficiency Project proposals to recommend to their respective Boards for approval.

(v) Solely for the purposes of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in Section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under Sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTOs’ Board as described in 9.3.7.2(b)(xi).
9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.3 Network Upgrades Associated with Incremental Auction Revenue Rights Requests.

When under Section 9.3.5 it is determined that the granting of an Incremental ARR request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Affected System’s tariff provisions.

9.4.4 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify Interregional Projects as: (i) Cross-Border Baseline Reliability Projects (“CBBRP”), (ii) Interregional Reliability Projects, (iii) Interregional Market Efficiency Projects, and (iv) Interregional Public Policy Projects, and (v) Targeted Market Efficiency Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.4.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. These Interregional Projects will be designated in accordance with the following criteria:
9.4.4.1.1 Cross-Border Baseline Reliability Project Criteria:

Projects that meet all of the following criteria will be designated as CBBRPs:

(i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria;

(ii) the project must be a baseline reliability project as defined under the MISO or PJM Tariffs.

9.4.4.1.2 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. Reliability projects in the MISO regional transmission planning process include Baseline Reliability Projects and Multi-Value Projects that meet Criterion 3 according to MISO’s OATT. MISO and PJM will quantify the benefits of an Interregional Reliability Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan that would be displaced if the proposed Interregional Reliability Project was included in the plan.

9.4.4.1.3 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.7 of the JOA;

(ii) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Market Efficiency Project or a Multi-Value Project that meets Multi-Value Project Criterion 2 or Criterion 3 under the terms of Attachment FF of the MISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM...
RTEP or MISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost; and

(iii) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.4.1.3.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the combined MISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposed project qualified as an Interregional Market Efficiency Project. The RTOs shall perform this evaluation as follows:

(a) The RTOs shall utilize their respective tariffs’ benefit metrics to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

(b) The costs applied in the cost allocation calculation pursuant to Section 9.4.4.2.2 shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.4.2.2 of the JOA, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and
also qualifies as a market efficiency project under the terms of Attachment FF of the MISO OATT.

9.4.4.1.4 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. Public policy projects in the MISO regional transmission planning process include Multi-Value Projects that meet Multi-Value Project Criterion 1 under the terms of Attachment FF to MISO’s OATT. Public policy projects in the PJM regional transmission planning process include both economic and reliability projects. MISO and PJM will quantify the benefits of an Interregional Public Policy Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan for purposes of cost allocation that would be displaced if the proposed Interregional Public Policy Project was included in the plan.

9.4.4.1.5 Targeted Market Efficiency Project Criteria:

Upgrades associated with Targeted Market Efficiency Projects must meet the following criteria:

(i) Are evaluated as part of a Coordinated System Plan or joint study process as described in Section 9.3.7.2(c) and demonstrated to have an expectation for substantial relief of identified historical market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project was approved;

(iii) Have an estimated installed cost less than $20 million in study year dollars;
(iv) Is determined to have expected future congestion relief, due to upgrade of that targeted Reciprocal Coordinated Flowgate, equal to the sum of annual congestion over the four (4) year period after the study year, that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs, in study year dollars, where:

a. Expected future congestion relief in the amount of the Reciprocal Coordinated Flowgate’s anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis;

b. Historical congestion in PJM will be quantified in accordance with PJM OATT, Attachment K-Appendix, Section 5.1. It will include charges associated with Day-ahead and Real-time market congestion for Market Buyers, Generating Market Buyers, and Market Sellers;

c. Historical congestions in MISO will be quantified in accordance with MISO OATT, Sections 39.2.9 “Day-Ahead Energy and Operating Reserve Market Process” and 40.2.15 “Real-Time Energy and Operating Reserve Market Process.” It will include charges associated with Day-Ahead and Real-Time market congestion for both load and generator buses; and

d. Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study year.

(v) Is recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO’s Board.

9.4.4.1.5.1 Determination of Benefits of Each RTO from a Targeted Market Efficiency Project

The RTO shall jointly evaluate the benefits to the combined markets and to each RTO for each potential Targeted Market Efficiency Project resulting from Section 9.3.7.2(c), according to the following process:

(i) With input from IPSAC, determine the estimated total installed project capital cost in study year dollars;

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars, where:

a. Expected future congestion relief is the sum of each RTO’s expected congestion relief, adjusted by market-to-market settlement payments.
9.4.4.2 Interregional Project Benefits and Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.4.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

(a) Method for Thermal Constraints: The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of each RTO to loading on the constrained facility requiring the need for the CBBRP. The loading contribution will be pre-determined using a joint RTO planning model developed and agreed to by the planning staffs of both RTOs. This model will form the basecase from which reliability needs on the combined systems will be determined for the Coordinated System Plan. The model, adjusted for the conditions driving the upgrade needs, will be used to calculate the DFAX for cost allocation purposes for each RTO, using a source of the aggregate of RTO generation (network resources) for each RTO to a sink of all Loads within that RTO. The DFAX is the appropriate distribution factor for the condition causing the upgrade; OTDF for contingency condition flow criteria violations, and PTDF for normal condition flow criteria violations. The DFAX calculation determines the MW flow impact attributable to each RTO on the constraint requiring the transmission system to be upgraded. The total load of each RTO for the condition modeled is multiplied by the DFAX associated with that RTO to determine the respective MW flow contribution of that RTO to the constraint. The RTOs will quantify the relative impact due to PJM’s system and the relative impact due to the MISO’s system and then will allocate between PJM and the MISO the load contributions to the reliability constraint on the system by calculating the relative impacts caused by each RTO. This methodology will determine the extent to which each RTO contributes to the need for a reliability upgrade consistent with the Coordinated System Plan modeling that determined the need for the upgrade. The MISO total load impacts will be allocated to the MISO and the PJM total load impacts will be allocated to PJM. PJM and the MISO will then reallocate their shares internally in accordance with their respective tariffs. By calculating the impacts in this manner, the RTOs will ensure that the relative contribution of each RTO (including both the aggravating and benefiting contributions of generation and load patterns within each RTO) to the need for a particular upgrade, is appropriately captured in the ensuing allocations, and that the allocation is consistent with the Coordinated System Plan modeling that determined the need for the upgrade.

(b) Method for Non-Thermal Constraints: The JRPC will establish an interface, comprised of a number of transmission facilities, to serve as a surrogate for allocation of cost responsibility for non-thermal constraints.
The interface will be established such that the aggregate flow on the
to the interface best represents the non-thermal constraint which the CBBRP is
proposed to alleviate. Allocation of cost responsibility for the non-thermal
constraint will be determined by applying the procedures described in this
Section to the interface serving as a surrogate for the constraint.

\(c\) \textit{Method for Projects that Also Qualify As Interregional Reliability
Projects: For an Interregional Project that meets the criteria of both a
CBBRP under Section 9.4.4.1.1 and an Interregional Reliability Project
under Section 9.4.4.1.2, the cost will be allocated in accordance with the
methodology set forth in Section 9.4.4.2.2.}

\textbf{9.4.4.2.2 Cost Allocation for an Interregional Reliability Project:}

The cost of an Interregional Reliability Project, selected in the regional
transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a
region will be determined by the ratio of the present value(s) of the
estimated costs of such region’s displaced reliability projects as agreed to
by the RTOs to the total of the present value(s) of the estimated costs of
the displaced reliability projects in both regions that have selected the
Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated
costs shall be determined by PJM and MISO in accordance with their
respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their
cost estimates for displaced reliability projects are determined in a similar
manner. The applicable discount rate(s) used for the MISO region shall be
the discount rate proposed by the Transmission Owner that produces the
cost estimate for the proposed project. The applicable discount rate(s)
used for the PJM region shall be the discount rate included in the
assumptions reviewed by the PJM Board of Managers each year for use in
the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region
pursuant to the cost allocation methodology contained in each region’s
respective regional transmission planning process.

\textbf{9.4.4.2.3 Cost Allocation for an Interregional Market Efficiency Project:}

For Interregional Market Efficiency Projects that meet all of the qualifications in
Section 9.4.4.1.2, the applicable project costs shall be allocated to the respective
RTOs in proportion to the net present value of the total benefits calculated for
each RTO pursuant to each RTO’s respective tariff.
9.4.4.2.4 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.4.3 Determination of Interregional Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the interregional cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC.

The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for the MISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred.
since the previous years’ basecase development. The joint RTO planning model will be available to any member of PJM or the MISO.

9.4.4.4 Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.4.5 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.4.6 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.
Attachment B

Revisions to the
PJM – MISO Joint Operating Agreement

(Clean Format)
9.3 **Coordinated System Planning.**
The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 **Single Party Planning.**
Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party’s OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties’ respective systems.

9.3.2 **Coordinated System Plan.**
The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan as further described in Section 9.3.7. The Coordinated System Plan shall also include the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.
9.3.3 **Analysis of Interconnection Requests.**
In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. The process for coordination of *interconnection* studies and Network Upgrades *is detailed below*:

(a) Consistent with the data exchange provisions of the manuals, the Parties will exchange current power flow modeling data annually and as necessary for the study and coordination of interconnection requests. This will include the associated update of the other Party’s relevant queue requests, contingency elements, monitoring elements data, and other data as may be required.

(b) The *coordinated interconnection studies* will determine the potential impact on the direct connect system and on the impacted Party. The direct connect system will be responsible for communicating coordinated interconnection study results to the direct connect interconnection customer.

(c) The Parties will coordinate and mutually agree on the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party.

(i) *The transmission reinforcement and the study criteria used in the coordinated interconnection studies will conform to and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and the Parties’ respective Tariffs.*

(ii) *The PJM and PJM transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the PJM transmission system when PJM evaluates the impact of MISO generation on PJM transmission facilities.*

(iii) *The MISO and MISO transmission owner study and reinforcement criteria will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact of PJM generation on MISO transmission facilities.*

(iv) *The identification of all impacts on the Parties’ transmission systems shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcements.*

(v) If the Parties cannot mutually agree on the nature of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.
The Parties will strive to minimize the costs associated with the coordinated study process.

(d) **During the course of its interconnection studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. These potential impacts shall be included in the PJM System Impact Study report along with any information regarding the validity of these impacts and any transmission system reinforcements received from MISO and the MISO transmission owners.**

(e) **Following issuance of the PJM Feasibility Study report and after the Interconnection Customer executes the PJM System Impact Study Agreement, PJM shall forward to MISO, at a minimum of twice per year (April 15 and October 15), information necessary for MISO and the MISO transmission owners to study the impact of the PJM Interconnection Request(s) on the MISO transmission system. MISO and the MISO transmission owners shall study the impact(s) of the PJM Interconnection Request(s) on the MISO transmission system and provide draft results to PJM by:**

   (i) March 1 for PJM Interconnection Request(s) provided to MISO on or before October 15 of the previous year; and

   (ii) September 1 for PJM Interconnection Request(s) provided to MISO on or before April 15 of the same year.

(f) **During the determination of reinforcements for an Interconnection Request that are required to mitigate MISO constraint(s), PJM and MISO may identify other planned non-MISO reinforcement(s) that may alleviate such constraint(s) inside the MISO region. Under such circumstances, any PJM interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. MISO shall determine the necessary injection limits associated with the PJM Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through MISO’s affected system analysis are inservice.**

(g) **During the course of MISO’s interconnection studies, MISO shall monitor the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. Those potential impacts shall be included in the MISO System Impact Study report along with any information regarding the validity of these impacts and possible mitigation received from PJM and the PJM transmission owners.**

(h) **Prior to commencing the MISO Definitive Planning Phase (“DPP”) study, MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) on the PJM**
transmission system. For the prescribed times when MISO provides this information to PJM, January 1 and July 1, PJM and the PJM transmission owners shall study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the draft results to MISO by:

(i) March 31 for requests submitted to PJM on or before January 7 of the same year; and

(ii) September 29 for requests submitted to PJM on or before July 7 of the same year.

(i) During the determination of reinforcements for an Interconnection Request that are required to mitigate PJM constraint(s), PJM and MISO may identify other planned non-PJM reinforcement(s) that may alleviate a constraint(s) inside the PJM region. Under such circumstances, any MISO interconnection project relying on those reinforcement(s) shall have limited injection rights until those reinforcement(s) are placed into service. PJM shall determine the necessary injection limits associated with the MISO Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through PJM’s affected system analysis are in-service.

(j) If the coordinated interconnection study identifies constraints that require infrastructure additions on the impacted system to mitigate them, then the potentially impacted Party may perform its own analysis, in conjunction with the direct connect Party’s Interconnection Studies. The interconnection customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate Facilities Study agreement as required under the impacted Party’s OATT.

(k) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(l) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such Network Upgrades in the appropriate study report prepared for the interconnection customer.

(m) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(n) The Interconnection Customer whose project requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the
appropriate Facilities Study Agreement as required under the impacted Party’s Tariff:

(o) In the event that Network Upgrades are required on the potentially impacted Party’s system, then interconnection service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

(p) Each Party will maintain a separate interconnection queue. The Parties will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

9.3.4 Analysis of Long-Term Firm Transmission Service Requests.
In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party’s business practices manuals that are publicly available on each Party’s website. Both Parties’ manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will coordinate the study of the request, pursuant to each Party’s business practices manuals, which will determine the potential impact on each Party’s system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party’s OASIS is unnecessary (i.e., the potentially impacted Party is “off the path”), then the potentially impacted Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process. The JRPC will develop
screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party’s system shall enter into the appropriate facilities study agreement as required under the impacted Party’s OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request’s Facilities Study. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the Party receiving the request will identify the need for such Network Upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.
9.3.5 **Analysis of Incremental Auction Revenue Rights Requests.**

The Parties will coordinate, as deemed appropriate, the conduct of any studies in response to a request for Incremental Auction Revenue Rights (“Incremental ARRs”) (“Incremental ARR Request”) made under one Party’s tariff to determine its impact on the other Party’s system. Results of such coordinated studies will be included in the impacts reported to the customer requesting Incremental ARRs as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) The Parties will coordinate the base Firm Flow Entitlement values associated with the Coordinated Flowgates that may be impacted by the Incremental ARR Request.

(b) Upon receipt of an Incremental ARR Request or the review of studies related to the evaluation of such request, the Party receiving the Incremental ARR Request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the Incremental ARR Request will notify the other Party and convey the information provided in the request in addition to but not limited to the list of impacted constrained facilities.

(c) During the System Impact Study, the potentially impacted Party may participate in the coordinated study by providing input to the studies to be performed by the Party receiving the Incremental ARR Request. The potentially impacted Party shall determine the Network Upgrades, if any, needed to mitigate constraints on identified impacted facilities. The Parties shall coordinate to ensure any proposed Network Upgrades maintain the reliability of each Party’s transmission system.

(d) Any coordinated System Impact Studies will be performed in accordance with the mutually agreed upon study timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement in accordance with applicable tariff provisions.

(e) During the Facilities Study, the potentially impacted Party may conduct its own Facilities Study as a part of Facilities Study being conducted by the Party that received the Incremental ARR request. The study cost estimates indicated in the Facility Study Agreement between the Party receiving the request and the Incremental ARR customer will reflect the costs and the associated roles of the study participants, including the potentially impacted Party. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.
(f) The Party receiving the Incremental ARR Request shall collect from the Incremental ARR customer, and forward to the potentially impacted Party, the agreed upon payments associated with the performance of such studies.

(g) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted Party, the Party receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the Incremental ARR customer.

(h) The construction of such Network Upgrades will be subject to the terms of the potentially impacted Party’s tariff, the agreement among owners transferring functional control of transmission facilities to the control of the potentially impacted Party, and applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party’s system, the Incremental ARR will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

1 Infra (b).
9.3.6 **Analysis of Generator Deactivations (retirements and suspensions).**

(a) The Party ("Noticed Party") receiving a new request from a generation owner to retire, deactivate, ormothball (or suspend operations as defined under the MISO Tariff) its generation unit will notify the other Party of such deactivation request no later than five (5) business days after receipt of the notice by the Noticed Party. The other Party ("Other Party") will determine if any study is required to evaluate potential impacts to its system due to the proposed generator deactivation in the Noticed Party’s system. Any studies required due to a notice to deactivate (retire or suspend operations as defined under the MISO Tariff) will be performed under each Party’s respective Tariff. Each Party’s regional study results will be documented and provided to the other Party for informational purposes only.

(b) Both Parties will share all information necessary to evaluate potential impacts to their respective systems due to the notice. Such coordination shall provide for:

(i) Exchange of current power flow modeling data as necessary for the study and coordination of generator deactivations (retirements and suspensions). This will include the associated update of the other Party’s generator availability, contingency elements, monitoring elements data, and other data as may be required.

(ii) Coordination by the Parties to align the assumptions of any analyses during development of the scope of any required studies. The scope design will include, as appropriate, evaluation of the transmission system against the criteria applicable to each Party for such studies.

(c) Following the exchange of information pursuant to section 9.3.6(b), the Other Party will conduct screening and evaluation of projects needed to mitigate identified impacts on its system. The Other Party will use reasonable efforts to perform an initial assessment and provide an indication of the impacts on its system to the Noticed Party within 65 days of receipt of the notice from the Noticed Party. The Other Party will provide a list of potential system reinforcements required on its system and estimated time for completion of those system reinforcements to the Noticed Party as soon as they are available.

(d) Each Party will be responsible for any regional Network Upgrades or other mitigation required on their respective system as a result of a request to deactivate (retirement or suspension).
(e) Any impact(s) on the Other Party’s system identified in the analysis will not be used to determine the need to retain the generator requesting to deactivate.

(f) The identification of Network Upgrades required for generator deactivation (retirement or suspension) in the Other Party’s system may require coordination through the JRPC. The Parties will endeavor to make such information available to the JRPC in a timely manner following publication of information through the Parties’ regional processes. Additional coordination, as may be needed, will be conducted pursuant to the Coordinated System Plan study process as mutually agreed to be the Parties in accordance with the provisions of Section 9.3.7.

(i) The JRPC will incorporate any needed regional upgrades that may be identified by the generator deactivation studies coordinated pursuant to this section 9.3.6 into the annual review processes of Section 9.3.7 for the purpose of determining if there is a more efficient or cost effective Interregional Reliability Project that may replace one or more of the identified regional Network Upgrades required for the generator deactivation.

(ii) The JRPC will consider the results of the deactivation analyses forwarded to the committee at the next scheduled JRPC meeting or within 30 days of receipt of the completed study information from both Parties. Depending on the timing of the receipt of the study information, the JRPC will determine the most appropriate process for including the regional deactivation results into the development of the Coordinated System Plan. Such process will include IPSAC review according to the Coordinated System Plan process of Section 9.3.7.

Throughout the interregional review process any confidentiality provisions of the Parties Tariff’s will be respected. Critical identified Interregional Reliability Projects for which the need to begin development is urgent will be presented to the Parties’ Boards for approval as soon as possible after identification through the Coordinated System Plan study process. Other identified Interregional Reliability Projects presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade.
9.3.7 Development of the Coordinated System Plan.

9.3.7.1

Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties’ systems. Each Party’s annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Section, to obtain financial compensation due to the impact of another Party’s plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

(a) Integrate the Parties’ respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation, market participant funded, or merchant transmission projects) and Network Upgrades identified jointly by the Parties, together with alternatives to Network Upgrades that were considered;

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties’ systems due to the integration described in the preceding part (a); and

(c) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.7.2

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.7.2.a; and 2) Coordinated System Plan study described in Section 9.3.7.2.b.

(a) Determine the Need for a Coordinated System Plan Study.

(i) On an annual basis, *beginning in the fourth quarter of each calendar year and continuing through the first quarter of the following calendar year*, the Parties shall perform an annual evaluation of transmission issues identified by each Party including issues from the respective Party’s market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party’s regional planning cycles.
(ii) The JRPC’s annual review of transmission issues shall include the following steps:
   a. Exchange of the following information during the fourth quarter of each calendar year:
      i. Regional issues and newly approved regional projects located near the interface or expected to impact the adjacent region;
      ii. Newly identified regional transmission issues for which there is no proposed solution;
      iii. Interconnection requests under coordination by the Parties located near the interface or expected to impact the adjacent region;
      iv. Market-to-market historical flowgate congestion between the Parties.
   b. Joint review by the Parties of regional issues and solutions in January of each calendar year;
   c. Receipt of Third Party issues in the first quarter of each calendar year;
   d. Review of regional issues with input from stakeholders at the IPSAC meeting conducted during the first quarter of each calendar year; and
   e. Decision by the JRPC on whether or not to conduct a Coordinated System Plan study.

(iii) The JRPC through each Party’s respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to be held in the first quarter of each year to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting for consideration by the IPSAC and JRPC.

(iv) Within 45 days following the annual issues evaluation meeting with IPSAC in the first quarter of the calendar year, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (1) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (2) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a
Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study within five business days of the JRPC’s decision.

(v) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study and identify whether it is a targeted study as defined in this Section at (vi) or a more complex, two-year cycle study as defined in this Section at (vii).

(vi) A Coordinated System Plan study may include targeted studies of particular areas, needs or potential expansions to ensure that the coordination of the reliability and efficiency of the Parties’ transmission systems will be conducted during the first half of the calendar year. In years when the Coordinated System Plan study includes only targeted studies as defined herein, they may be conducted at any time during the calendar year but will be targeted for completion within the calendar year in which they are identified.

(vii) A Coordinated System Plan study may include more complex, longer duration studies involving joint model development that addresses reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

(viii) When a Coordinated System Plan study is determined to be necessary by the JRPC, the specific study process steps will depend on the type and scope of the study. The JRPC shall provide the timely, specific deadlines for each step in the Coordinated System Plan study in a timely fashion following the JRPC’s decision to initiate such study.

(b) Coordinated System Plan Study Process

(i) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review
and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment at an IPSAC meeting scheduled no later than 30 days after the decision to conduct a Coordinated System Plan study.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented. Targeted studies will utilize the best available regional models for transmission and market efficiency analysis.

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party’s criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.7.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. The JRPC will develop joint study models consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be
accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) When Coordinated System Plan studies are undertaken pursuant to a two-year study cycle defined in this Section at (a)(vii), the following schedule will be followed unless otherwise mutually agreed to be the Parties.

a. Parties will provide updated identification of regional issues identified in this Section at (a) in the first year of the two-year cycle from June through September.

b. Regional models will be made available to the IPSAC for stakeholder review and comment in the first year of the two-year cycle from June through September.

c. Stakeholder Interregional Project proposals, satisfying applicable regional and interregional requirements, will be accepted by PJM in its proposal windows for Long-lead Projects and Economic-based Enhancements or Expansions as detailed in Schedule 6 of the PJM Amended and Restated Operating Agreement.

d. Stakeholder identification of Interregional Project proposals satisfying the applicable regional and interregional requirements will be accepted in the MISO regional process typically between January through March of the second year of the two-year cycle.

e. The Parties will evaluate each project proposal in its regional process during the second year of the two-year cycle to determine if a project is eligible for inclusion in the respective regional plans. An Interregional Project must be included in each Party’s regional plan to become an approved Interregional Project. The Parties shall target the end of the second year of the two-year cycle to include an approved Interregional Project.
(viii) The IPSAC will have the opportunity to provide input into the development of potential solutions. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.4.1.

(ix) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses. After the conclusion of the Coordinated System Plan study, any project included in the Coordinated System Plan and designated for interregional cost allocation, if not already engaged in the regional review process, will be submitted to the regional processes for review according to Section 9.3.7.2(b)(x).

(x) At the completion of the Coordinated System Plan study, the JRPC shall produce a report documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.4.1. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report. The JRPC shall provide the Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study report. The final Coordinated System Plan study report shall be posted on each Party’s website.

(xi) The JRPC’s recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties’ Boards for approval and implementation using each Party’s procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties’ Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform
the IPSAC of the outcome of each Party’s review of the recommended Interregional Projects.

(c) Targeted Market Efficiency Project Study

The Coordinated System Plan study may include a Targeted Market Efficiency Project study consistent with Section 9.3.7.2(b)(iii). The Targeted Market Efficiency Project study will evaluate, analyze, and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border. Identified issues under this section will be expected to persist and are not expected to be substantially alleviated by system changes planned in the five (5) year planning horizon. Identification of issues will include, but not be limited to, the RTO’s determination, based on historical operational information, of any historical flowgate congestion known to be caused by outage conditions. The RTOs will not consider for purposes of a Targeted Market Efficiency Project study, historical congestion on a Reciprocal Coordinated Flowgate caused by outages or will determine a proportionally reduced amount of congestion associated with that flowgate, as appropriate. Any Targeted Market Efficiency Project study initiated by the JRPC under this section will be conducted under the process defined for a Coordinated System Plan study, except as modified by this section and the following subsections.

(i) Issues identified in the Targeted Market Efficiency Project study will be reviewed to determine the cause of the market issues, including: (a) the specific limiting elements, (b) verification of the ratings of the limiting elements, (c) whether approved, planned system changes may alleviate the issue, (d) whether outages contribute to all or a portion of the historical congestion, (e) estimates of the cost of upgrading the limiting elements, and (f) whether upgrades to the limiting elements could substantially relieve the constraints;

(ii) Using the results of the review under subsection (i) and the applicable criteria of Section 9.4, the JRPC will post results of the analysis for input from the IPSAC and will solicit proposals for Targeted Market Efficiency Projects that meet the criteria of Sections 9.3.7.2(c) and 9.4 applicable to a Targeted Market Efficiency Project;

(iii) The JRPC will determine the list of limiting element upgrades and Targeted Market Efficiency Project proposals to analyze the benefits to PJM and MISO for presentation to and input from the IPSAC;
(iv) Based on the analysis and stakeholder process conducted consistent with Sections 9.3.7.2(c) and 9.4, the JRPC will determine any Targeted Market Efficiency Project proposals to recommend to their respective Boards for approval;

(v) Solely for the purposes of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in Section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under Sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTOs’ Board as described in 9.3.7.2(b)(xi).
9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

When under Section 9.3.3 it is determined that a generation or merchant transmission interconnection to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.2 Network Upgrades Associated with Transmission Service Requests.

When under Section 9.3.4 it is determined that the granting of a long-term firm delivery service request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Party’s OATT.

9.4.3 Network Upgrades Associated with Incremental Auction Revenue Rights Requests.

When under Section 9.3.5 it is determined that the granting of an Incremental ARR request with respect to a Party’s system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Affected System’s tariff provisions.

9.4.4 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify Interregional Projects as: (i) Cross-Border Baseline Reliability Projects (“CBBRP”), (ii) Interregional Reliability Projects, (iii) Interregional Market Efficiency Projects, (iv) Interregional Public Policy Projects, and (v) Targeted Market Efficiency Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.4.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. These Interregional Projects will be designated in accordance with the following criteria:
9.4.4.1.1 Cross-Border Baseline Reliability Project Criteria:

Projects that meet all of the following criteria will be designated as CBBRPs:

(i) by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria;

(ii) the project must be a baseline reliability project as defined under the MISO or PJM Tariffs.

9.4.4.1.2 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. Reliability projects in the MISO regional transmission planning process include Baseline Reliability Projects and Multi-Value Projects that meet Criterion 3 according to MISO’s OATT. MISO and PJM will quantify the benefits of an Interregional Reliability Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan that would be displaced if the proposed Interregional Reliability Project was included in the plan.

9.4.4.1.3 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i) is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.7 of the JOA;

(ii) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Market Efficiency Project or a Multi-Value Project that meets Multi-Value Project Criterion 2 or Criterion 3 under the terms of Attachment FF of the MISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM...
RTEP or MISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost; and

(iii) addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a GLDF of 5% or greater with respect to serving load in that adjacent market, as determined using the Coordinated System Plan power flow model.

9.4.4.1.3.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the combined MISO and PJM markets, and to each market individually, by evaluating multiple metrics using a multi-year analysis to determine whether a proposed project qualified as an Interregional Market Efficiency Project. The RTOs shall perform this evaluation as follows:

(a) The RTOs shall utilize their respective tariffs’ benefit metrics to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

(b) The costs applied in the cost allocation calculation pursuant to Section 9.4.4.2.2 shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable to the constructing transmission owner(s).

To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners’ most recent after-tax embedded cost of capital weighted by each transmission owner’s total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner’s most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.4.2.2 of the JOA, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and
also qualifies as a market efficiency project under the terms of Attachment FF of the MISO OATT.

9.4.4.1.4 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region’s cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. Public policy projects in the MISO regional transmission planning process include Multi-Value Projects that meet Multi-Value Project Criterion 1 under the terms of Attachment FF to MISO’s OATT. Public policy projects in the PJM regional transmission planning process include both economic and reliability projects. MISO and PJM will quantify the benefits of an Interregional Public Policy Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan for purposes of cost allocation that would be displaced if the proposed Interregional Public Policy Project was included in the plan.

9.4.4.1.5 Targeted Market Efficiency Project Criteria:

Upgrades associated with Targeted Market Efficiency Projects must meet the following criteria:

(i) Are evaluated as part of a Coordinated System Plan or joint study process as described in Section 9.3.7.2(c) and demonstrated to have an expectation for substantial relief of identified historical market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project was approved;

(iii) Have an estimated installed cost less than $20 million in study year dollars;
(iv) Is determined to have expected future congestion relief, due to upgrade of that targeted Reciprocal Coordinated Flowgate, equal to the sum of annual congestion over the four (4) year period after the study year, that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs, in study year dollars, where:

a. Expected future congestion relief in the amount of the Reciprocal Coordinated Flowgate’s anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis;

b. Historical congestion in PJM will be quantified in accordance with PJM OATT, Attachment K-Appendix, Section 5.1. It will include charges associated with Day-ahead and Real-time market congestion for Market Buyers, Generating Market Buyers, and Market Sellers;

c. Historical congestions in MISO will be quantified in accordance with MISO OATT, Sections 39.2.9 “Day-Ahead Energy and Operating Reserve Market Process” and 40.2.15 “Real-Time Energy and Operating Reserve Market Process.” It will include charges associated with Day-Ahead and Real-Time market congestion for both load and generator buses; and

d. Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study year.

(v) Is recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO’s Board.

9.4.4.1.5.1 Determination of Benefits of Each RTO from a Targeted Market Efficiency Project
The RTO shall jointly evaluate the benefits to the combined markets and to each RTO for each potential Targeted Market Efficiency Project resulting from Section 9.3.7.2(c), according to the following process:

(i) With input from IPSAC, determine the estimated total installed project capital cost in study year dollars;

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars, where:

a. Expected future congestion relief is the sum of each RTO’s expected congestion relief, adjusted by market-to-market settlement payments.
9.4.4.2 Interregional Project Benefits and Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.4.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

(a) **Method for Thermal Constraints:** The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of each RTO to loading on the constrained facility requiring the need for the CBBRP. The loading contribution will be pre-determined using a joint RTO planning model developed and agreed to by the planning staffs of both RTOs. This model will form the basecase from which reliability needs on the combined systems will be determined for the Coordinated System Plan. The model, adjusted for the conditions driving the upgrade needs, will be used to calculate the DFAX for cost allocation purposes for each RTO, using a source of the aggregate of RTO generation (network resources) for each RTO to a sink of all Loads within that RTO. The DFAX is the appropriate distribution factor for the condition causing the upgrade; OTDF for contingency condition flow criteria violations, and PTDF for normal condition flow criteria violations. The DFAX calculation determines the MW flow impact attributable to each RTO on the constraint requiring the transmission system to be upgraded. The total load of each RTO for the condition modeled is multiplied by the DFAX associated with that RTO to determine the respective MW flow contribution of that RTO to the constraint. The RTOs will quantify the relative impact due to PJM’s system and the relative impact due to the MISO’s system and then will allocate between PJM and the MISO the load contributions to the reliability constraint on the system by calculating the relative impacts caused by each RTO. This methodology will determine the extent to which each RTO contributes to the need for a reliability upgrade consistent with the Coordinated System Plan modeling that determined the need for the upgrade. The MISO total load impacts will be allocated to the MISO and the PJM total load impacts will be allocated to PJM. PJM and the MISO will then reallocate their shares internally in accordance with their respective tariffs. By calculating the impacts in this manner, the RTOs will ensure that the relative contribution of each RTO (including both the aggravating and benefiting contributions of generation and load patterns within each RTO) to the need for a particular upgrade, is appropriately captured in the ensuing allocations, and that the allocation is consistent with the Coordinated System Plan modeling that determined the need for the upgrade.

(b) **Method for Non-Thermal Constraints:** The JRPC will establish an interface, comprised of a number of transmission facilities, to serve as a surrogate for allocation of cost responsibility for non-thermal constraints.
The interface will be established such that the aggregate flow on the interface best represents the non-thermal constraint which the CBBRP is proposed to alleviate. Allocation of cost responsibility for the non-thermal constraint will be determined by applying the procedures described in this Section to the interface serving as a surrogate for the constraint.

(c) **Method for Projects that Also Qualify As Interregional Reliability Projects:** For an Interregional Project that meets the criteria of both a CBBRP under Section 9.4.4.1.1 and an Interregional Reliability Project under Section 9.4.4.1.2, the cost will be allocated in accordance with the methodology set forth in Section 9.4.4.2.2.

9.4.4.2.2 Cost Allocation for an Interregional Reliability Project:

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.4.2.3 Cost Allocation for an Interregional Market Efficiency Project:

For Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.2, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to each RTO’s respective tariff.
9.4.4.2.4 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region’s respective regional transmission planning process.

9.4.4.3 Determination of Interregional Cost Allocation Share Outside of Coordinated System Plan:

Either RTO may request that a project be tested against the interregional cost allocation criteria during the interim periods between periodic formal releases of the Coordinated System Plan. The RTOs will conduct reviews between the formal cycles on at least an annual basis. Such tests will be performed on the best available joint planning model, as determined by the JRPC.

The joint planning model will be a minimum 5-year horizon case, modeling peak summer conditions, and will be developed by February of each year. It will be based on the current RTEP basecase for PJM and the current MTEP basecase for the MISO. The basecase developed by each RTO will be based on documented procedures, which, in turn, will guide the development of the joint RTO planning model. Any disputes that arise will be resolved through the dispute resolution procedures documented in Article XIV. Each year the model will be updated by the RTOs to include changes to long term firm transmission service, load forecast, topology changes, generation additions/retirements and any other relevant system changes that may have occurred.
since the previous years’ basecase development. The joint RTO planning model will be available to any member of PJM or the MISO.

9.4.4.4 Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.4.5 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.4.6 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.