Big Rivers
ELECTRIC CORPORATION

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September 14, 2018

RECEIVED

SEP 14 2018

PUBLIC SERVICE
COMMISSION

VIA HAND DELIVERY

Ms. Gwen R. Pinson
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
Frankfort, KY 40601

Re: *In the Matter of: 2017 Integrated Resource Plan of Big Rivers Electric Corporation - Case No. 2017-00384*

Dear Ms. Pinson:

Enclosed for filing in the above-referenced matter are an original and ten (10) copies of: (*i*) the public version of Big Rivers Electric Corporation's responses to the Second Request for Information of the Public Service Commission Staff, the Supplemental Request for Information of the Office of the Attorney General, and the Supplemental Request for Information of Ben Taylor and the Sierra Club; and (*ii*) a petition for confidential treatment of the confidential information contained in these responses. Also enclosed is one (1) sealed copy of the confidential information being filed pursuant to the petition for confidential treatment.

I certify that, on this date, copies of this letter and all public attachments were served on each of the persons listed on the attached service list by Federal Express.

Sincerely,

TSK

Tyson Kamuf
Corporate Attorney,
Big Rivers Electric Corporation
tyson.kamuf@bigrivers.com

cc: Service List
Roger D. Hickman

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

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SEP 14 2018

PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	CASE NO. 2017-00384

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL TREATMENT

1. Big Rivers Electric Corporation ("Big Rivers") hereby petitions the Kentucky Public Service Commission ("Commission"), pursuant to 807 KAR 5:001 Section 13 and KRS 61.878, to grant confidential treatment to certain information contained in Big Rivers' responses and/or the attachments to Big Rivers' responses to Item 8 of the Commission Staff's Second Request for Information ("PSC 2-8"); Item 9 of the Attorney General's Supplemental Request for Information ("AG 2-9"); and Items 1, 2, 7, 10, 23, and 32 of Ben Taylor and the Sierra Club's Supplemental Request for Information ("SC 2-1," "SC 2-2," "SC 2-7," "SC 2-10," "SC 2-23," and "SC 2-32," respectively).

2. The information for which Big Rivers seeks confidential treatment is hereinafter referred to as the "Confidential Information." The Confidential Information consists of the confidential terms of power sales agreements; projected staffing costs; projected variable operating costs; projected power market prices and costs; projected costs to restart idled generating units, retire generating units, or to convert generating units to natural gas; and other terms, such as totals and

projected net margins on transactions, that can be used to calculate other Confidential Information.

3. One (1) copy of the paper pages containing Confidential Information, with the Confidential Information highlighted with transparent ink, printed on yellow paper, or otherwise marked "CONFIDENTIAL," is being filed with this petition. A copy of those pages, with the Confidential Information redacted, or a sheet noting that the entirety of the pages have been redacted, is being filed with the original and each of the ten (10) copies of Big Rivers' responses to the information requests filed with this petition. 807 KAR 5:001 Section 13(2)(a)(3).

4. A copy of this petition and a copy of Big Rivers' responses to the information requests with the Confidential Information redacted have been served on all parties to this proceeding. 807 KAR 5:001 Section 13(2)(b). A copy of the Confidential Information has been provided to all parties that have executed a confidentiality agreement.

5. If and to the extent the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission in writing. *See* 807 KAR 5:001 Section 13(10)(b).

6. As discussed below, the Confidential Information is entitled to confidential treatment based upon 807 KAR 5:001 Sections 13(4) and (9) and/or KRS 61.878(1)(c)(1). *See* 807 KAR 5:001 Section 13(2)(a)(1).

I. Information Exempted from Public Disclosure by 807 KAR 5:001 Sections 13(4) and (9)

7. Big Rivers' responses and/or the attachments to Big Rivers' responses to PSC 2-8, SC 2-2, and SC 2-32 contain Confidential Information consisting of information about the confidential terms of power sales agreements that Big Rivers has entered into with OMU, KyMEA, NextEra, and three entities in Nebraska, as well as related information including projected revenues, margins, and other totals that, if publicly disclosed, would reveal the confidential terms of those agreements. Big Rivers filed each of these agreements with the Commission, and when doing so, Big Rivers requested confidential treatment of the confidential terms of the agreements.

8. The Confidential Information in the attachments to Big Rivers' response to SC 2-1 consists of Confidential Information from three progress reports that Big Rivers filed, along with requests for confidential treatment of that information, as part of the focused audit that the Commission ordered in its April 25, 2014, order in P.S.C. Case No. 2013-00199.

9. 807 KAR 5:001 Section 13(9) provides:

> Use of confidential material. (a) A person who files any paper that contains material that has previously been deemed confidential or for which a request or motion for confidential treatment is pending shall submit one (1) copy of the paper with the adjudged or alleged confidential material underscored or highlighted, and ten (10) copies of the paper with those portions redacted; and
>
> > 1. If the confidential status of the material has been determined previously, a written notice identifying the person who originally submitted the material, the date on which a determination on the materials confidentiality was made and, if applicable, the case number in which the determination was made; or

> 2. If a request for confidential treatment of the material is pending, a written notice identifying the person who made the request and the date on which the request was submitted.

10. The Commission granted confidential treatment to the Confidential Information in the Nebraska contracts by order dated September 10, 2014, in *In the Matter of: Big Rivers Electric Corporation Filing of Wholesale Contracts Pursuant to KRS 278.280 and KAR 5:011 Section 13*, P.S.C. Case No. 2014-00134, and the Commission should continue to afford confidential treatment to that information for the reasons stated in that order and the related petition, which Big Rivers requests be incorporated herein by reference.

11. On January 10, 2018, the Commission's Executive Director issued three letters granting confidential treatment to the Confidential Information contained in Big Rivers' April 1, 2016, October 3, 2016, and April 3, 2017, focused audit progress reports, and the Commission should continue to afford confidential treatment to that information for the reasons stated in those letters and the related petitions, which Big Rivers requests be incorporated herein by reference.

12. On August 5, 2016, Big Rivers filed the KyMEA contract with the Commission in Case No. 2016-00306, along with a petition for confidential treatment of the Confidential Information contained in that agreement. On October 21, 2016, and June 1, 2018, Big Rivers filed the NextEra contracts with the Commission along with petitions for confidential treatment of the Confidential Information contained in those agreements. *See* TFS 2016-00584 and TFS 2018-00272. On June 27, 2018, Big Rivers filed the OMU contract with the Commission along with a petition for confidential treatment of the Confidential Information

contained in that agreement. *See* TFS 2018-00318. All of these petitions for confidential treatment are pending.

13. 807 KAR 5:001 Section 13(4) provides, "Pending action by the [C]ommission on a motion for confidential treatment or by its executive director on a request for confidential treatment, the material specifically identified shall be accorded confidential treatment." As such, the Confidential Information relating to the KyMEA, NextEra, and OMU agreements should be afforded confidential treatment while the petitions are pending and thereafter for the reasons stated in those petitions, which Big Rivers requests be incorporated herein by reference.

II. <u>Information Exempted from Public Disclosure by KRS 61.878(1)(c)(1)</u>

14. KRS 61.878(1)(c)(1) protects "records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records." Section A below explains that Big Rivers operates in competitive environments in the wholesale power market and in the credit market. Section B below shows that the Confidential Information is generally recognized as confidential or proprietary. Section C below demonstrates that public disclosure of the Confidential Information would permit an unfair commercial advantage to Big Rivers' competitors.

A. Big Rivers Faces Actual Competition.

15. As a generation and transmission cooperative, Big Rivers competes in the wholesale power market. This includes not only the short-term bilateral energy market, the day-ahead and real time energy and ancillary services markets, and the

capacity market to which Big Rivers has access by virtue of its membership in Midcontinent Independent System Operator, Inc. ("MISO"), but also forward bilateral long-term agreements and wholesale agreements with utilities and industrial customers. Big Rivers' ability to successfully compete in the market is dependent upon a combination of its ability to: (i) obtain the maximum price for the power it sells, and (ii) keep its cost of production as low as possible. Fundamentally, if Big Rivers' cost of producing a unit of power increases, its ability to sell that unit in competition with other utilities is adversely affected.

16. Big Rivers also competes for reasonably priced credit in the credit markets, and its ability to compete is directly impacted by its financial results. Lower revenues and any events that adversely affect Big Rivers' margins will adversely affect its financial results and potentially impact the price it pays for credit. A competitor armed with Big Rivers' proprietary and confidential information will be able to increase Big Rivers' costs or decrease Big Rivers' revenues, which could in turn affect Big Rivers' apparent creditworthiness. A utility the size of Big Rivers that operates generation and transmission facilities will always have periodic cash and borrowing requirements for both anticipated and unanticipated needs. Big Rivers expects to be in the credit markets on a regular basis in the future, and it is imperative that Big Rivers improve and maintain its credit profile.

17. Accordingly, Big Rivers has competitors in both the power and capital markets, and its Confidential Information should be protected to prevent the imposition of an unfair competitive advantage.

B. The Confidential Information is Generally Recognized as Confidential or Proprietary

18. The Confidential Information for which Big Rivers seeks confidential treatment under KRS 61.878(1)(c)(1) is generally recognized as confidential or proprietary under Kentucky law.

19. As noted above, Big Rivers' responses and/or the attachments to Big Rivers' responses to PSC 2-8, SC 2-2, and SC 2-32 contain Confidential Information consisting of, or that would reveal, the confidential terms of power sales agreements, which Big Rivers is prohibited from publicly disclosing under nondisclosure agreements between the parties to those power sales agreements. KRS 278.160 specifically recognizes that terms of a special contract are not required to be publicly disclosed if such terms are entitled to protection under KRS 61.878(1)(c)(1). KRS 278.160(3). Moreover, the Commission has previously granted confidential treatment to the confidential terms of such power sales agreements. *See, e.g., In the Matter of: Big Rivers Electric Corporation Filing of Wholesale Contracts Pursuant to KRS 278.280 and KAR 5:011 Section 13*, Order, P.S.C. Case No. 2014-00134 (Sept. 10, 2014).

20. The attachments to Big Rivers' responses to SC 2-2 and SC 2-32 also contain Confidential Information consisting of projections of Big Rivers' variable operating costs and other expenses and projections of energy and capacity prices

and costs. The Confidential Information in Big Rivers' response to AG 2-9 consists of project staffing costs. The Confidential Information in Big Rivers' response to SC 2-7 consists of projections of power market prices and projected revenues that reveal Big Rivers' projections of power market prices. The Confidential Information in Big Rivers' response to SC 2-23 and in the attachment to Big Rivers' response to SC 2-10 consists of the projected costs to restart idled generating units, retire generating units, or convert generating units to natural gas. This information provides insight into Big Rivers' cost of producing power; the prices at which Big Rivers is willing to buy or sell power; and the amounts Big Rivers is willing to pay for capital projects. Information such as this which bears upon a company's detailed inner workings is generally recognized as confidential or proprietary. *See, e.g., Hoy v. Kentucky Indus. Revitalization Authority*, 907 S.W.2d 766, 768 (Ky. 1995) ("It does not take a degree in finance to recognize that such information concerning the inner workings of a corporation is 'generally recognized as confidential or proprietary'"); *Marina Management Servs. v. Cabinet for Tourism, Dep't of Parks*, 906 S.W.2d 318, 319 (Ky. 1995) (unfair commercial advantage arises simply from "the ability to ascertain the economic status of the entities without the hurdles systemically associated with the acquisition of such information about privately owned organizations").

Additionally, the Commission has previously granted confidential treatment to similar information. *See, e.g., In the Matter of: 2014 Integrated Resource Plan of Big Rivers Electric Corporation*, Order, P.S.C. Case No. 2014-00166 (August 26, 2014) (granting confidential treatment to fuel cost projections, power price projections, projected environmental compliance-related capital and O&M costs, NPV results of production cost model runs, and rate projections); *In the Matter of: Big Rivers Electric Corporation Filing of Wholesale Contract Pursuant to KRS 278.180 and KAR 5:011 Section 13*, Order, P.S.C. Case No. 2014-00134 (September 30, 2014) (granting confidential treatment to projected energy and capacity prices); *id.*, Order (October 9, 2014) (granting confidential treatment to financial forecast, projections of capital expenditures, projects of revenues and expenses from off-system sale, and commercial negotiations); *id.*, Order (November 21, 2014) (granting confidential treatment to forecasted rates, revenues, and costs).

21. The Confidential Information is not publicly available, is not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information, and is not disseminated to others without a legitimate need to know and act upon the information.

22. Accordingly, the information for which Big Rivers seeks confidential treatment is recognized as confidential or proprietary under Kentucky law and is entitled to confidential protection as further discussed below.

C. Public Disclosure of the Confidential Information Would Permit an Unfair Commercial Advantage to Big Rivers' Competitors.

23. Public disclosure of the Confidential Information would permit an unfair commercial advantage to Big Rivers' competitors. As discussed above, Big Rivers faces actual competition in the wholesale power market and in the credit

market. It is likely that Big Rivers would suffer competitive injury if that Confidential Information was publicly disclosed.

24. The Confidential Information includes material such as Big Rivers' projections of operating costs, power prices, capital project costs, and other information revealing Big Rivers' cost of producing power. If that information is publicly disclosed, market participants would have insight into the prices at which Big Rivers is willing to buy and sell power, and the amount Big Rivers is willing to pay for capital projects, and those market participants could manipulate the bidding process when selling to or buying from Big Rivers, increasing Big Rivers' costs or reducing its revenues. Increased costs would impair Big Rivers' ability to generate power at competitive rates and thus to compete in the wholesale power markets. Furthermore, any competitive pressure that adversely affects Big Rivers' revenue and margins could make the company appear less creditworthy and thus impair its ability to compete in the credit markets. These effects were recognized in P.S.C. Case No. 2003-00054, in which the Commission granted confidential treatment to bids submitted to Union Light, Heat & Power ("ULH&P"). ULH&P argued, and the Commission implicitly accepted, that if the bids it received were publicly disclosed, contractors on future work could use the bids as a benchmark, which would likely lead to the submission of higher bids. *In the Matter of: Application of the Union Light, Heat and Power Company for Confidential Treatment*, Order, P.S.C. Case No. 2003-00054 (August 4, 2003); *see also In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc.*

from May 1, 2007 through October 31, 2007, Letter, P.S.C. Case No. 2007-00523 (February 27, 2008). The Commission also implicitly accepted ULH&P's further argument that the higher bids would lessen ULH&P's ability to compete with other gas suppliers. *In the Matter of: Application of the Union Light, Heat and Power Company for Confidential Treatment*, Order, P.S.C. Case No. 2003-00054 (August 4, 2003).

25. Similarly, the Commission recently granted confidential treatment to pricing information provided by Cumberland Valley Electric, Inc. ("Cumberland Valley") in P.S.C. Case No. 2018-00056. *In the Matter of: Application of Cumberland Valley Electric, Inc. for Commission Approval for a Certificate of Public Convenience and Necessity to Install an Advanced Metering Infrastructure (AMI) System Pursuant to KRS 807 KAR 5:001 and KRS 278.020*, Order, P.S.C. Case No. 2018-00056 (May 9, 2018). In that case, the Commission recognized "that the specific cost information may be used to the financial detriment of Cumberland Valley and its ratepayers by allowing potential future vendors to bid just under the cost of its current vendor, which, in turn, would place Cumberland Valley at a competitive disadvantage." *Id.*

26. The same competitive harm that the Commission recognized in P.S.C. Case Nos. 2003-00054 and 2018-00056 would befall Big Rivers if the Confidential Information in this case were publicly disclosed.

27. Public disclosure of the Confidential Information would provide potential purchasers of power from Big Rivers; potential sellers of power to Big

Rivers; potential contractors on capital projects; and other wholesale power providers competing against Big Rivers for purchases or sales power with insight into the prices and the terms under which Big Rivers is willing to buy and sell. These market participants could use this information as a benchmark, leading to higher costs, lower revenues, or less favorable terms to Big Rivers, hurting Big Rivers' ability to compete in the wholesale power and credit markets.

28. Public disclosure of the confidential terms of special contracts would also cause competitive harm to Big Rivers. In P.S.C. Case No. 2003-00054, the Commission additionally implicitly accepted ULH&P's argument that the bidding contractors would not want their bid information publicly disclosed, and that disclosure would reduce the contractor pool available to ULH&P, which would drive up ULH&P's costs, hurting its ability to compete with other gas suppliers. *In the Matter of: Application of the Union Light, Heat and Power Company for Confidential Treatment*, Order, P.S.C. Case No. 2003-00054 (August 4, 2003). Similarly, in *Hoy v. Kentucky Indus. Revitalization Authority*, the Kentucky Supreme Court found that without protection for confidential information provided to a public agency, "companies would be reluctant to apply for investment tax credits for fear the confidentiality of financial information would be compromised. *Hoy v. Kentucky Indus. Revitalization Authority*, 907 S.W.2d 766, 769 (Ky. 1995).

29. In Big Rivers' case, Big Rivers is currently in negotiations with potential counterparties for power purchase and sale agreements, and expects to engage in negotiations with other counterparties in the future. If confidential

treatment of the confidential terms of the power sales contracts is denied, potential counterparties would know that the confidential terms of their contracts could be publicly disclosed, which could reveal information to their competitors about their competitiveness. Because many companies would be reluctant to have such information disclosed, public disclosure of the Confidential Information would likely reduce the pool of counterparties willing to negotiate with Big Rivers, reducing Big Rivers' ability to buy and sell power on favorable terms and impairing its ability to compete in the wholesale power and credit markets.

30. Accordingly, the public disclosure of the information that Big Rivers seeks to protect pursuant to KRS 61.878(1)(c)(1) would provide Big Rivers' competitors with an unfair commercial advantage. As such, the Commission should grant confidential treatment to the Confidential Information.

III. Time Period

31. Pursuant to 807 KAR 5:001 Section 13(2)(a)(2), Big Rivers requests that the Confidential Information be afforded confidential treatment for the time periods explained below.

32. With regard to Big Rivers' responses and/or the attachments to Big Rivers' responses to PSC 2-8, SC 2-2, and SC 2-32, Big Rivers requests that the Confidential Information in the Nebraska contracts be afforded confidential treatment indefinitely pursuant to the Commission's September 10, 2014, order in P.S.C. Case No. 2014-00134. Big Rivers requests that the confidential terms of the other power sales agreements, and the related revenue projects, also remain confidential indefinitely because the competitive harm resulting from public

disclosure of confidential contract terms is not time dependent for the reasons stated above.

33. Big Rivers requests that the Confidential Information contained in the focused audit progress reports attached to its response to SC 2-1 be afforded confidential treatment for the time periods contained in the Commission's letters granting confidential treatment to that information, for the reasons stated in those letters and the related petitions.

34. Big Rivers requests that all other Confidential Information remain confidential for a period of five (5) years from the date of this petition, which should allow sufficient time for the projected data to become sufficiently outdated such that it could not be used to determine similar confidential information at that time or to competitively disadvantage Big Rivers.

IV. Conclusion

35. Based on the foregoing, the Confidential Information is entitled to confidential treatment pursuant to 807 KAR 5:001 Section 13 and KRS 61.878. If the Commission disagrees that Big Rivers' Confidential Information is entitled to confidential treatment, due process requires the Commission to hold an evidentiary hearing. *See Utility Regulatory Comm'n v. Kentucky Water Serv. Co., Inc.*, 642 S.W.2d 591 (Ky. App. 1982).

WHEREFORE, Big Rivers respectfully requests that the Commission grant this petition and classify and treat as confidential the Confidential Information.

On this the 14th day of September, 2018.

Respectfully submitted,

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Corporate Attorney
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Counsel for Big Rivers Electric Corporation

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Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF	)	Case No.
BIG RIVERS ELECTRIC CORPORATION	)	2017-00384

Responses to the Office of the Attorney General's Supplemental Request for Information dated August 17, 2018

FILED: September 14, 2018

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION CASE NO. 2017-00384

Response to the Office of the Attorney General's Supplemental Request for Information dated August 17, 2018

September 14, 2018

Item 1) *Refer to Big Rivers' Response to the Attorney General's Initial Request for Information, Item 8. Explain the nature and extent of the repairs and/or modifications which would be required to return Reid Unit 1 to service.*

- ***a.*** *Using the above information, explain whether Big Rivers is able to provide an estimate of the additional years of lifespan which would then calculated for Reid Unit 1. If so, provide the new projected lifespan.*
- ***b.*** *If the remaining lifespan cannot be provided or calculated, provide the lifespan for comparable units with a similar age, run time and operating characteristics.*

Response) Returning Reid Unit 1 to service would require conversion of the unit to burn Natural Gas and typical unit Maintenance Outage repairs and inspections.

- a. Until the specific details regarding the nature and extent of the repairs and/or modifications required to return Reid Unit 1 to service are known, Big Rivers is unable to provide an estimate of the additional years of lifespan or new Reid Unit 1 projected lifespan.
- b. The lifespan for comparable units, with a similar age, run time and operating characteristics, is typically 55 to 65 years with 400,000 operating hours.

Witness) Michael T. Pullen

Item 2) *Refer to Big Rivers' Response to the Sierra Club's Initial Request for Information, Item 6. Explain the projected timeline for planning to restore interconnection service into MISO for the Coleman Station.*

a. *How long after a decision to restart Coleman would Big Rivers begin this process of entering the generation queue?*

b. *How long does it typically take to complete the generation interconnection queue process? Explain fully.*

Response) The projected timeline for planning to restore interconnection service into the Midcontinent Independent System Operator, Inc. ("MISO") for the Coleman Station is dependent upon the issues and processes described in the responses to sub-parts a and b. Additional details can be found in the MISO Generator Interconnection Business Practice Manual attached to this response.

a. When Big Rivers would begin the process of entering the generation queue after a decision to restart Coleman would depend on the duration of the longest critical path task to return Coleman to service. Acquiring the necessary permitting and approvals, plus installing and commissioning the appropriate environmental control technologies, are likely to be the longest duration tasks.

b. MISO conducts two Definitive Planning Phase (DPP) cycles per year to evaluate generator interconnection requests. Each cycle consists of three (3) phases. MISO will utilize reasonable efforts to complete the DPP cycle within three hundred fifty-five (355) calendar days. The development and execution of a generator interconnection agreement is expected to be completed within an additional one hundred fifty (150) calendar days for a total generator interconnection process time of five hundred five (505) calendar days.

Witnesses) Michael T. Pullen (*a. only*)
Christopher S. Bradley (*b. only*)

Case No. 2017-00384
AG 2-2 (MTP) (Att) - MISO Business Practice Manual Generator Interconnection

Manual No. 015

Business Practices Manual

Generator Interconnection

Disclaimer

This document is prepared for informational purposes only, to support the application of the provisions of the Tariff and the services provided thereunder. MISO may revise or terminate this document at any time at its discretion without notice. While every effort will be made by MISO to update this document and inform its users of changes as soon as practicable, it is the responsibility of the user to ensure use of the most recent version of this document in conjunction with the Tariff and other applicable documents, including, but not limited to, the applicable NERC Standards. Nothing in this document shall be interpreted to contradict, amend, or supersede the Tariff. MISO is not responsible for any reliance on this document by others, or for any errors or omissions or misleading information contained herein. In the event of a conflict between this document, including any definitions, and either the Tariff, NERC Standards, or NERC Glossary, the Tariff, NERC Standards, or NERC Glossary shall prevail. In the event of a conflict between the Tariff and the NERC Standards, or NERC Glossary, the Tariff shall prevail until or unless the Federal Energy Regulatory Commission ("FERC") orders otherwise. Any perceived conflicts or questions should be directed to the Legal Department.

Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-015-r17	Revised Coordination language for studies between MH, MPC and MISO in Section 6.5. Inserted new Section 6.7 for language on Existing Generating Facility modification evaluation	N. Shah	SEP-27-2017
BPM-015-r16	GI Process Flow Diagram update, GI dispatch assumptions changes, application of local planning criteria and applicable reliability criteria.	P. Muncy N. Shah	AUG-01-2017
BPM-015-r15	Revised to reflect the January 4, 2017 FERC Order for Queue Reform and Annual Review.	P. Muncy	JUN-14-2017
BPM-015-r14	Correction to constraint criteria in Section 6.1.1.1.6	P. Muncy	MAR-15-2017
BPM-015-r13	Annual ERIS Evaluation and Interim Deliverability Study language revisions. Conditions to GIA (Appendix A10) language revisions. Annual Review Completed	P. Muncy	JAN-27-2017
BPM-015-r12	Annual Review completed. External Network Resource Interconnection Service Process and additional language, Applicable Reliability Criteria and Applicable Transmission Owner Criteria, Coordination of GI studies between SPP and MISO, Annual Deliverability and AERIS Study language revisions, Provisional Interconnection Agreement Limit Methodology.	D. Vasquez	FEB-12-2016
BPM-015-r11	Revised A10 Conditionality Methodology, Wind Generation Plant Power Factor and Low Voltage Ride Through criteria, Study of PJM Interconnection Requests, Modeling process updates, Generation to Include and Deposit Refunding to match Tariff changes. Added section on M2 Refunding Process & Annual ERIS and Annual Interim	C. Craven	MAR-19-2015

	Deliverability Study.		
BPM-015-r10	Revised Backfill procedures	C. Craven	OCT-31-2014
BPM-015-r9	Revised to add language regarding MISO-PJM Coordination of GI Projects. Also updated Table of Contents. Annual Review completed.	S. Turner	JAN-17-2014
BPM-015-r8	Annual Review completed. Revised Midwest ISO to Midcontinent Independent System Operator, Inc.	P. Muncy	AUG-20-2013
BPM-015-r7	Revised to reflect the November 1st, 2011 filing of the modifications to the Generator Interconnection Procedures and Agreement.	E. Laverty	NOV-13-2012
BPM-015-r6	Annual Review completed	E. Laverty	SEP-11-2012
BPM-015-r5	MISO Rebranding Changes	E. Nicholson	MAR-21-2011
BP-015-r5	Revised to reflect the sixth M2 milestone option and separate deliverability analysis into its own subsection.	E. Laverty	MAR-21-2011
BPM-015-r4	Revised to reflect July 15th filing for Shared Network Upgrades	E. Laverty	JUL-16-2010
BPM-015-r3	Revised to reflect numbering protocol	E. Laverty	JAN-01-2010
TP-BPM-004-r2	Revised to reflect the Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.	E. Laverty	JAN-06-2009
TP-BPM-004-r1	Revised to reflect the June 25th, 2008 filing of the modifications to the Generator Interconnection Procedures and Agreement.	J. Doner	AUG-25-2008

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1. Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM) for Generator Interconnection* includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about MISO BPMs in general. The second section (Section 1.2) is an introduction to this BPM in particular. The third section (Section 1.3) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

1.1. Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of MISO markets, provisions of transmission reliability services, and compliance with MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

1.2. Purpose of this Business Practices Manual

This *BPM for Generator Interconnection* contains the business practices of MISO in implementing Attachment X of its Open Access Transmission, Energy and Operating Reserves Markets Tariff (Tariff). These practices are intended to supplement the Tariff, and to the extent that there is a conflict between the Tariff and these practices, the Tariff controls.

MISO prepares and maintains this BPM for Generator Interconnection as it relates to the reliable operation of MISO's region of authority. This BPM conforms and complies with the Agreement of Transmission Owners to Organize MISO, Federal Energy Regulatory Commission (FERC) Order 2000, MISO's Tariff, North American Electric Reliability Corporation (NERC) (the Electric Reliability Organization (ERO)) operating policies, and the applicable Regional Entities' reliability principles, guidelines, and standards and is designed to facilitate administration of efficient Energy and Operating Reserve Markets.

1.3. References

Other reference information related to this BPM includes:

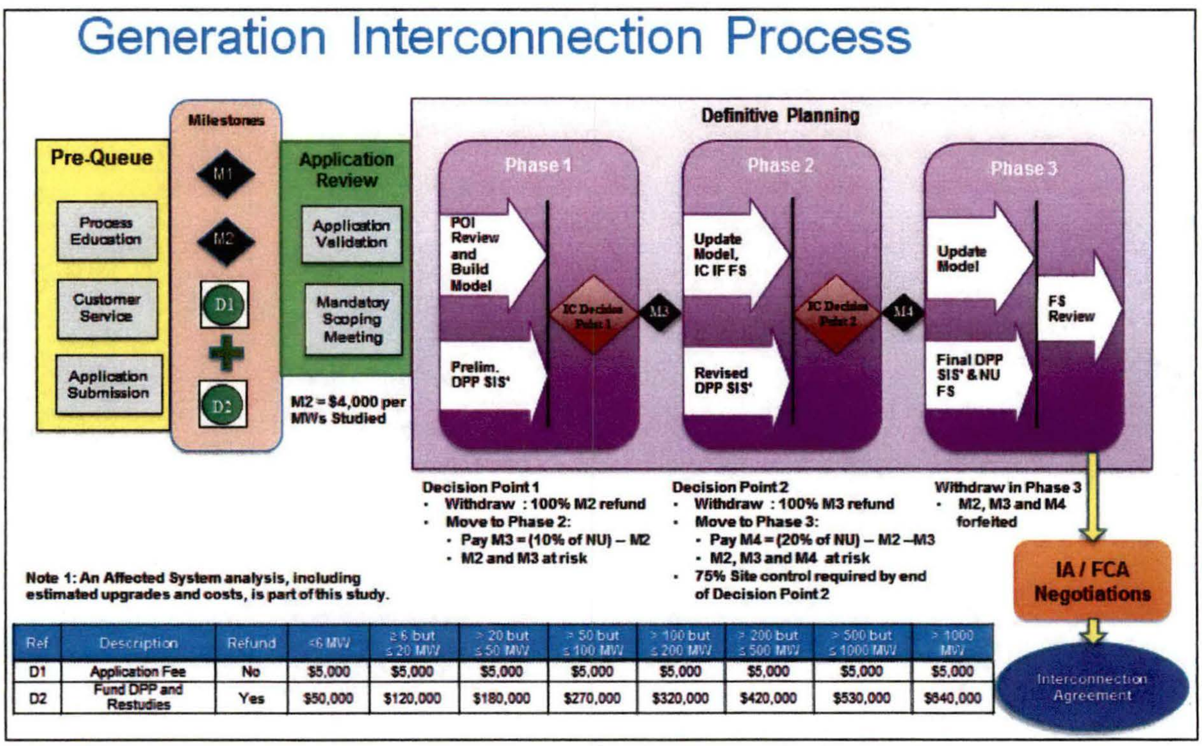
- BPM 001 Market Registration
- BPM 004 FTR and ARR
- BPM 010 Network and Commercial Model
- BPM 020 Transmission Planning
- Agreement of the Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (MISO Agreement)
- The Tariff
- Attachment X (Generator Interconnection Procedures and Agreement) of the Tariff

2. Generator Interconnection Process Overview

The Generator Interconnection Process is divided into three phases:

- Pre-Queue (represented by yellow in the diagram)
- Application Review (green)
- Definitive Planning (purple)

An overview of the process is shown in Figure 2-1. The process incorporates interaction between generator Interconnection Customers and MISO and uses Milestone achievement as a method of moving Interconnection Requests (IRs) through the queue. Milestones (represented by black diamonds in the diagram) serve as control checkpoints where MISO assesses IRs based on pre-defined criteria. Milestone achievement is a key determinant in how an IR is progressing through the process. Milestones may be technical (such as a stability model) or business-related (such as proof of Site Control).



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but ≤ 1000 MW	> 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 2-1 Generator Interconnection Process Overview

3. Pre-Queue Phase

The Pre-Queue Phase is designed to provide the Interconnection Customers an overview of the process, timeline, and expectations pertaining to the output of the Generator Interconnection process. The goal of the Pre-Queue Phase is to provide various channels for communication between the Interconnection Customer and MISO so that the Interconnection Customer is well informed about the queue process and requirements in every phase of the process. Figure 3.1 outlines the steps involved in the Pre-Queue Phase.

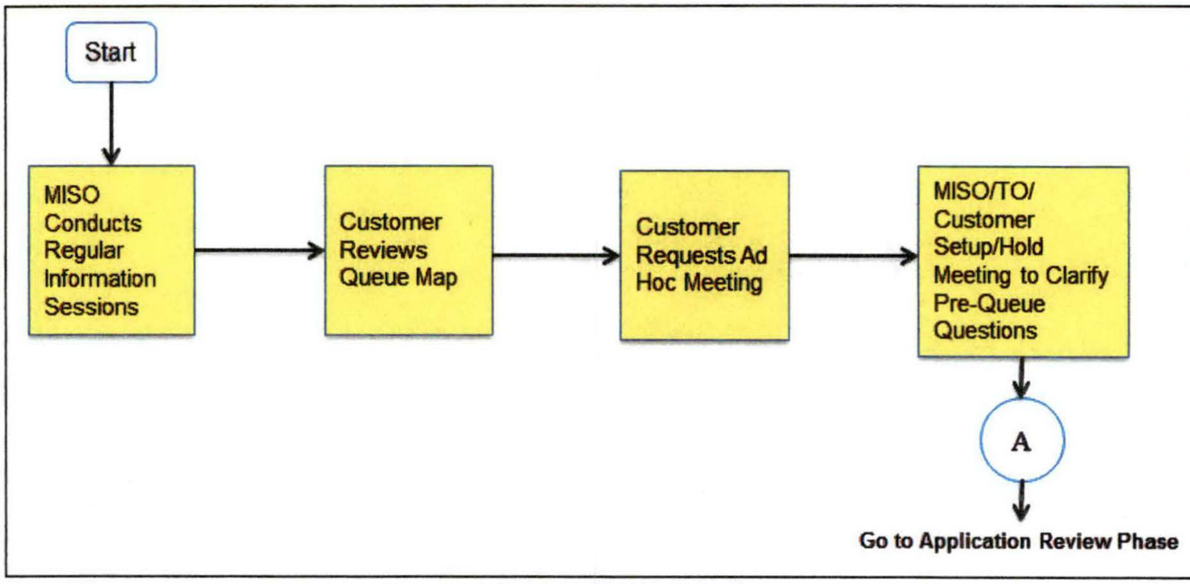


Figure 3-1 Overview of Pre-Queue Phase

3.1. Resources Available

Prior to entering the queue, an Interconnection Customer can utilize various resources available to familiarize themselves with the Tariff, queue processing and Milestones in the process. The MISO website will have online training programs, learning tools, contour maps indicating incremental transfer capability on the system, and other informational material. These programs are provided to help educate Interconnection Customers about the queue rules, process steps and requirements in each phase, to prepare them for successful completion of the MISO Generator Interconnection process. Additionally, Interconnection Customers can participate in the periodically scheduled information sessions or request a meeting to discuss specific issues.

3.1.1. Contour Map

MISO will post a contour map presenting an indicative estimate of the transmission capacity based on a relative pattern of incremental injection capability under first contingency conditions in the MISO footprint. The intent of this contour map is to provide Interconnection Customers an indication of the time it would take to study and eventually connect their project at the desired location. Generally an area with a large concentration of Interconnection Requests will have a low or negative incremental transfer capability. Therefore, studies would take longer to mitigate constraints and construction would take longer to build new transmission, thereby prolonging the overall time to interconnect a project in that area. Note that the purpose of the contour map is to provide guidance to an Interconnection Customer for making an informed decision. The map should not be treated as a substitute for studies. There may be other complex and physical limitations on the Transmission System which will be revealed only after detailed planning and engineering studies.

Once the Base Case for the Definitive Planning Phase System Impact Study is finalized, the updated assumptions will be used to refresh the contour map. The contour map will be developed for the near term and out year scenario. The contour map represents the incremental injection capacity at each bus in the MISO footprint under N-1 condition. The following steps are involved in developing the contour map:

- The power flow model developed for the current System Impact studies will be used for the purpose of this analysis.
- A transfer of 10,000 MW (subject to change in future as the network topology changes) is simulated from each bus in each MISO Local Balancing Authority to the whole MISO footprint and a First Contingency Incremental Transfer Capability (FCITC) analysis is performed using a load flow software tool. A distribution factor cutoff of three (3%) is used for the purpose of this analysis. This gives the incremental injection capacity at each bus.
- The injection capacity at each bus is decremented by the existing and queued generation at the bus to obtain the net injection capacity that is available. For this purpose, the nameplate rating of the generation (Pmax) is considered.
- The net injection capacity at each bus is mapped to the Geographical Information Systems (GIS) coordinates and the information is fed into the PowerWorld Corporation's PowerWorld Simulator tool to generate the contour map.
- A sample contour map is shown in Appendix A of this BPM.

3.1.1.1 Ongoing Efforts

MISO will continue to review the process and business practices for potential improvements on an ongoing basis. To address the transmission limitations in highly constrained areas, MISO will coordinate the transmission projects to accommodate the queued requests. MISO will continue to coordinate the Generator Interconnection process with the other planning activities outside the queue to provide the Interconnection Customer with more cost-efficient and timely solutions to their Interconnection Request.

3.2. Regularly Scheduled Information Sessions

MISO conducts on-the-road workshops on a quarterly basis for Interconnection Customers with a desire to participate and become familiar with the interconnection process and/or ask questions. All workshops are open to any potential or existing Interconnection Customers, Transmission Owners, Affected Systems, and other RTOs/ISOs wishing to learn about the MISO Generator Interconnection process. The workshops will address topics such as Milestones in the process, study timelines, Interconnection Customer inputs, requirements to enter each phase, estimated costs, Interconnection Customer responsibilities, etc. The schedule for all workshops will be posted in advance on the MISO website, at the Generator Interconnection page.

The workshops will be conducted in either the Carmel, IN or Eagan, MN MISO offices and will move based on an alternating schedule or at the request of the potential participants. Depending on interest and requests in the queue, locations may be revised in the future to include locations outside MISO offices.

3.3. Ad Hoc Information Sessions

Interconnection Customer can request an ad hoc information session with MISO and likely affected Transmission Owners in the following circumstances:

i. Interconnection Customer has identified a site location for a potential project
ii. Interconnection Customer has questions unique to his situation
iii. Interconnection Customer wants to get a better understanding of the available Points of Interconnection near their project site and any known issues on the local Transmission System
iv. If Interconnection Customer's questions or concerns were not addressed in the monthly update calls or during the on-the-road workshops

In order to request an ad hoc information session, the Interconnection Customer will submit an online request. The request will entail filling out a form which would include a tentative agenda for the meeting and specific questions. MISO will review the request for a meeting and decide which Transmission Owners to invite for the meeting. Within five (5) Business Days of receiving the request, MISO will send an email notification to Interconnection Customer with earliest available dates/times for the meeting, which will be scheduled within thirty (30) Calendar Days of receiving the request, unless another date is agreed upon by MISO and Interconnection Customer. An example of the template form to request a meeting is included in Appendix B of this manual.

MISO may review the following information in the meeting with the Interconnection Customer:

i. Contour map details in the area
ii. Existing loadings on the transmission outlet from the project site
iii. General stability and short circuit issues in the area
iv. General voltage issues including the ride through capabilities of the Generating Facility
v. General power quality issues including voltage flicker and harmonics
vi. General local and regional reliability issues
vii. Results of any previously completed study at or near the same location
viii. Estimated timing of request proceeding to the Definitive Planning Phase
ix. Estimated in-service date for the Interconnection Request
x. Any other existing information which could be helpful for the Interconnection Customer

4. Application Review Phase

The Application Review Phase, as depicted in Figure 4.1, will include preliminary work required before a study can begin. During information review, MISO will communicate with the Interconnection Customer to verify the information provided in the application and clarify any ambiguity.

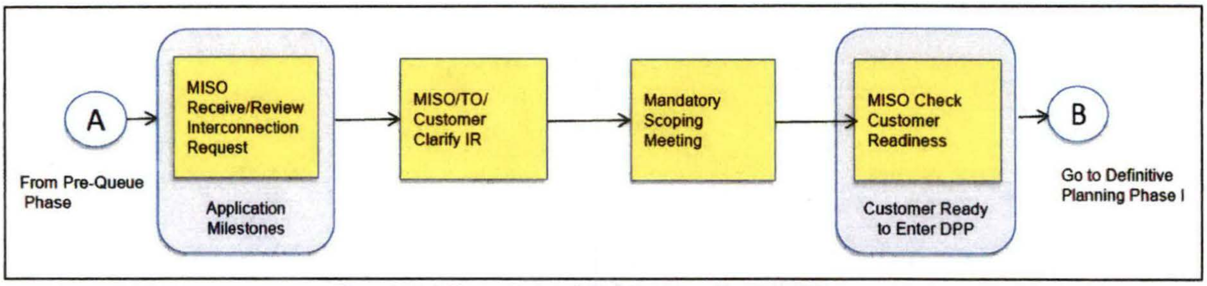


Figure 4-1 Overview of Application Review Phase

4.1. Scoping Meeting

Upon receiving a new Interconnection Request, MISO will review the information and data provided to verify that the Interconnection Request is complete and valid. MISO will send an acknowledgement of receiving a valid application or a request for additional information to the Interconnection Customer within five (5) Business Days of receiving the application. An Interconnection Request will not be accepted until all of the required sections are completed in the Application. The Interconnection Customer must provide any additional information requested to constitute a valid request at least forty-five (45) Calendar Days prior to the start of the next Definitive Planning Phase cycle. Within ten (10) Business Days after the receipt of a valid Interconnection Request MISO will provide a summary of the request to the Interconnection Customers and likely affected Transmission Owners. MISO shall establish a date that is agreeable to the Interconnection Customer and the Transmission Owner for a mandatory Scoping Meeting. That date will be at least five (5) Business Days prior to and no more than forty-five (45) Calendar Days prior to the start of the Definitive Planning Phase, unless mutually agreed upon by MISO, the Transmission Owner and the Interconnection Customer. MISO, the Interconnection Customer, and the Transmission Owner must attend the Scoping Meeting. MISO shall use Reasonable Efforts to include any other Affected System Operators in the Scoping Meeting.

Topics for discussion during the Scoping Meeting may include, but are not limited to:

i. Consider a reasonable number of alternative interconnection options to determine potential feasible Points of Interconnection.
ii. General Facility loadings
iii. General stability and short circuit issues in the area
iv. General voltage issues including the ride through capabilities of the Generating Facility
v. General power quality issues including voltage flicker and harmonics
vi. General local and regional reliability issues
vii. Diagrams and/or layout of applicable substations and transmission lines

The Interconnection Customer may as a result of the Scoping Meeting modify its Point of Interconnection. The Interconnection Customer will have five (5) Business Days from the date of the Scoping Meeting to submit the modified Point of Interconnection to MISO. Any issues or questions that arise during the Scoping Meeting will be addressed by the responsible parties within a timeframe agreed upon by the meeting participants before the end of the Scoping Meeting.

4.2. Initial Screening

All Interconnection Requests will go through a set of screenings before they can enter the Definitive Planning Phase. This screening will include verifying the application submitted has the required technical information, met the necessary Milestones, and study deposits.

4.2.1. Application Milestones (M1)

The Interconnection Customer must meet the requirements of Milestone (M1) in order for the application to be determined valid by MISO. The application Milestone (M1) will include *all* of the requirements in Section 4.2.1.1, Section 4.2.1.1.1, and Section 4.2.1.2.

4.2.1.1 Non-Technical Requirements

- Complete Application (Appendix 1 with Attachments A, B and C).
- The (D1) Application Fee paid at least forty-five (45) Calendar Days prior to the start of the next DPP cycle.
- The (D2) DPP Study Funding deposit paid at least forty-five (45) Calendar Days prior to the start of the next DPP cycle.

- Proof of minimum of seventy-five percent (75%) Site Control or one hundred thousand dollar ($100,000) deposit in lieu of Site Control (See Section 4.2.1.1.1 for details):
    - Project site map indicating lease/ownership interest boundaries.
    - Copies of each agreement or agreement signature pages with a complete sample agreement.
    - Document signed by a company executive that states all the listed agreements are on file in their entirety, all referenced land is within the proposed project boundaries, and those agreements constitute seventy-five percent (75%) or greater ownership of the project's total site. This document should also include a statement as necessary regarding land for which Site Control cannot be obtained due to federal, state, or local regulatory/ permitting requirements or obligations.
- Must supply a W-9 form for accounting purposes.
- Attend a mandatory Scoping Meeting. Figure 5-1 Overview of Definitive Planning Phase

4.2.1.1.1 Site Control Requirements Detail

The Interconnection Customer needs to demonstrate proof of Site Control for at least seventy-five percent (75%) of the project's total site at the time of the Interconnection Request application. Site Control is defined as documentation demonstrating ownership, leasehold interest in, or a right to develop a site for the purpose of constructing a Generating Facility and when applicable the Interconnection Facilities, and that the site has sufficient land area equal to at least seventy-five percent (75%) of that required to support the size and type of the Generating Facility proposed. This can be demonstrated by providing MISO with copies of each agreement, or the agreement signature pages, and a complete sample agreement. Additionally, a project site map indicating the lease and/or ownership boundaries must be included. Finally, a signed Site Control Affidavit signed by a company executive attesting that the Interconnection Customer has a minimum of seventy-five percent (75%) Site Control must be provided. Alternatively, the Interconnection Customer may pay a one hundred thousand dollar ($100,000) deposit in lieu of Site Control. This Site Control deposit is refundable upon future demonstration of Site Control.

The Interconnection Customer must provide proof of a minimum of seventy-five percent (75%) Site Control by the end of Interconnection Customer Decision Point II. After Site Control evidence is provided, the one hundred thousand dollar ($100,000) Site Control deposit will be refunded. If the Interconnection Customer fails to provide the Site Control evidence by the end of Interconnection Customer Decision Point II, then the project will be deemed withdrawn and any Site Control deposit will be refunded. The minimum of seventy-five (75%) Site Control threshold shall apply throughout the generation interconnection process, to include the Interconnection Customer's Site Control demonstration requirement within a certain amount of time as specified in the Generation Interconnection Agreement following its effective date.

In cases where the Interconnection Customer cannot partially or fully demonstrate Site Control for Interconnection Facilities as a result of regulatory/ permitting requirements, obligations, and processes, and thereby not achieve the seventy-five percent (75%) Site Control threshold, the following steps are required:

1. The Site Control Affidavit signed by a company executive shall include a statement that federal, state, and local regulatory/ permitting requirements, obligations related to Site Control for all or part of the Interconnection Facilities cannot be reasonably obtained, and detail what portions of the Interconnection Facilities this applies to. This shall serve as demonstration of the regulatory requirements, noted immediately above, causing the Interconnection Customer to not be able to provide Site Control demonstration for all or portion of the Interconnection Facilities.
2. The Transmission Provider will continue to allow the one hundred thousand dollar ($100,000) deposit in lieu of Site Control, if the Interconnection Customer provides a signed Affidavit by a company executive attesting to lack of Site Control associated with Interconnection Facilities as noted in 1). This shall be applicable throughout the Generation Interconnection Procedures to include any Site Control demonstration requirements specified in the Generation Interconnection Agreement.

MISO shall at each stage in the process provide a statement to the Interconnection Customer from senior management that Site Control documentation has been reviewed, along with specification of any deficiencies MISO finds with such documentation. Site Control documentation that has already been provided with the application and deemed not deficient, will also be considered valid documentation as permissible by the Tariff at later stages in the Generation Interconnection Process, to include Decision Point II, and Site Control documentation required once the Generation Interconnection Agreement is effective.

4.2.1.2 Technical Requirements

- Definitive gross and net generator output (MW) as measured at the POI
- Definitive Point of Interconnection (POI)
    - Only one POI may enter into DPP, unless required by State regulations to take two POI's
- Definitive one-line diagram for the POI
    - Information shall include:
        - Breaker layout and bus configuration (if available)
        - Number of generators
        - The zero sequence impedance for the generators (if available)
        - Distance from the collector substation to the POI, referenced in miles, including line impedance
        - If the POI is a line tap: the distance from the tap to the endpoints of the existing line, referenced in miles
        - Generator step up (GSU) transformer data and the collector substation transformer data (if applicable)
        - For inverter based generators, FERC Order 827 requires:
            - Location and size of any dynamic and/or static VAR compensation devices
            - Equivalent collector system impedance
- All Generator Types: Actual Stability Model representing the dynamics of the Generating Facility in a .dyr, .obj or .lib file format and the instruction manual (Models to be compatible with the PSS/E version of the DPP Base Case)
    - Wind: If the model is not available, a letter attesting to the type of turbine technology and reactive power capability at the POI
    - For inverter based/non-synchronous generators, FERC Order 827 requires:
        - Demonstration that the plant can meet a PF of 0.95 lead/lag at the high side of the main GSU(s) (The TO's planning criteria will supersede if they require a more stringent PF)
        - Base turbine or inverter reactive capability
    - For inverter based (wind or solar) generators, the IC shall provide the short circuit modeling instruction manual and associated model data
- All Generator Types: **All applicable information requested in Attachment A of Appendix 1**

** FERC Order 827:*
https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2016-08-04%20Docket%20No.%20ER16-2374-000.pdf
**The Interconnection Customer must submit one application for each site. Additionally, multiple Interconnection Requests can be submitted for a single site (each application will require a separate deposit in this case).*

- Financial Milestones:
  There are no financial Milestones attached to the Milestone (M1) submission. (However there are the (D1) Application fee and (D2) DPP Study Funding deposit which occur at the same time; please refer to Section 4.2.4).

4.2.2. Definitive Planning Phase Entry Milestones (M2)

The requirements for the Definitive Planning Phase (DPP) Entry Milestone (M2) are comprised of the items that follow. At the (M2) Milestone submission stage, the Interconnection Customer must meet *all* of the (M1) requirements, plus *the DPP Entry Milestone* in the form of a cash deposit or an irrevocable letter of credit in the amount of four thousand dollars ($4,000) per MW. If an Interconnection Customer is required by a state regulatory body to take two POIs through the study process, satisfaction of the non-technical Milestones is not required for the second Interconnection Request. All technical and non-technical Milestones and study deposits must be received by MISO no later than forty-five (45) Calendar Days prior to the next scheduled Definitive Planning Phase start date.

4.2.2.1 Requirements

- (M2) Definitive Planning Phase Entry Milestone Deposit
  - Cash or irrevocable letter of credit in the amount of four thousand dollars ($4,000) per MW for the project

**(M2) cash deposit or irrevocable letter of credit would be fully refundable upon withdrawal prior to Interconnection Customer Decision Point I. Please see section 6.2.11 for more information. For detail on Letter of Credit requirements see Section 4.2.3.*

When the (M1) and (M2) Milestones are received and validated, a project will be placed in the Definitive Planning Phase.

4.2.3. Letter of Credit Requirements

The Letter of Credit should clearly specify the "Issuer," the "Account Party", "Beneficiary (MISO)," the term for which the Letter of Credit will remain open, and the dollar amount available. It should also include a statement as to the instructions and terms for funds disbursement. The party issuing the Letter of Credit must have a minimum corporate debt rating of "A-" by S&P, "A3" by Moody's, and "A-" by Fitch. All costs associated with obtaining the Letter of Credit will be the responsibility of the Interconnection Customer. If the Letter of Credit option is chosen to fulfill the DPP Entry Milestone it would need to remain open until submission of the first GIA Milestone payment or withdrawal.

4.2.4. Study Deposits and Refunds

Study deposits are those deposits from the Interconnection Customer that are put towards the cost of performing the interconnection studies. As depicted in Figure 4.2 and described in the following Sections, there is the (D1) Application Fee, (D2) Study Funding deposit, and (M2) DPP Entry deposit required for an Interconnection Request to proceed through the process.

Thirty (30) Calendar Days after the execution of a permanent GIA with conditions, Interconnection Customer may replace any non-encumbered balance of the study deposits with an irrevocable letter of credit reasonably acceptable to MISO. After MISO acceptance of the letter of credit, MISO will refund the cash remaining in the Interconnection Customer's study deposits.

In the event of restudy, MISO shall notify the Interconnection Customer providing the option to submit the cash equivalent of the letter of credit within thirty (30) Calendar Days; thereby reducing the letter of credit in the amount of their deposit. Should the Interconnection Customer fail to respond within the requested timeframe, MISO shall draw upon the letter of credit as necessary to cover incurred restudy expenses

Additional studies available for projects:

Deliverability Only Study

Deposit for a deliverability only study – The study funding deposit for an Interconnection Request to change ER Interconnection Service to NR Interconnection Service for a Generating Facility in Commercial Operation or with an executed GIA shall be the same as for a new Interconnection Request, per Section 3.3 of the GIP. The (D1) Application Fee and (D2) DPP

Study Funding deposit is also required at the time of application for a deliverability only study request. The (M2) DPP Entry Milestone deposit is required as well, in the form of four thousand dollars ($4,000) per MW, and must be paid at least forty-five (45) Calendar Days prior to the start of the next Definitive Planning Phase cycle.

External NR Interconnection Service Study

The study funding deposit for an Interconnection Request to determine availability of NR Interconnection Service for a Generating Facility external to MISO shall be the same as for a new Interconnection Request, per Section 3.3 of the GIP. The (D1) Application Fee and (D2) DPP Study Funding deposit is also required at the time of application for an External NR Interconnection Service study request. The (M2) DPP Entry Milestone deposit is required as well, in the form of four thousand dollars ($4,000) per MW, and must be paid at least forty-five (45) Calendar Days prior to the start of the next Definitive Planning Phase cycle. To be eligible for study, a Generating Facility must meet at least one of the following criteria:

i. In-service
ii. Under Construction
iii. Have an Interconnection Agreement with the Transmission Provider to which it directly physically connects

Deliverability study for External Resources will be processed in the same manner as for any other Generating Facility that has existing injection rights and is requesting Network Resource Interconnection Service on the MISO system.

Upon receiving a valid application, MISO will place the request in the next applicable DPP cycle and evaluate it for deliverability test only. No additional analysis will be performed.

Generating Facilities that are granted a Service Agreement for External NR Interconnection Service will be required to procure Transmission Service to the MISO border in order to validate the External NRIS request.

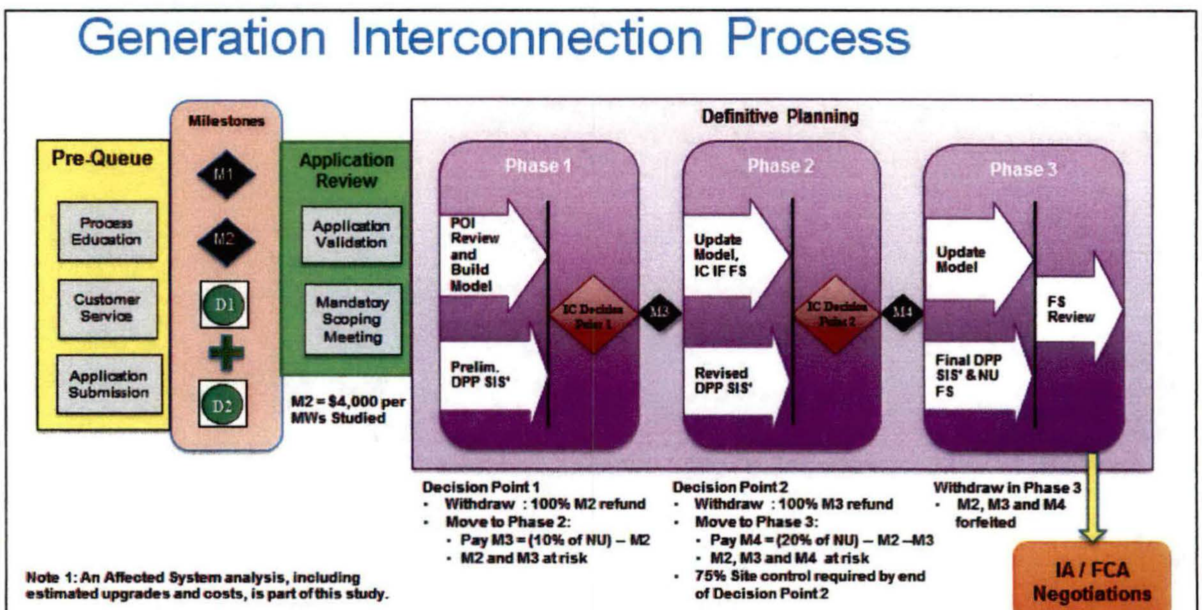
Optional Interconnection Study

The Interconnection Customer can request an Optional Interconnection Study for their project solely to get additional information/results to help them in making business decisions on their project. Request for a study can be made on a standalone basis or in parallel with an ongoing Interconnection Study. The studies will be performed based on the assumptions outlined by the

Interconnection Customer. Results of such informational studies will be non-binding. Interconnection Customer shall execute the Optional Interconnection Study Agreement Appendix 5 of the GIP within ten (10) Business Days from receipt and deliver the Optional Interconnection Study Agreement Appendix 5 of the MISO Tariff, the technical data, and a deposit of sixty thousand dollars ($60,000) to MISO. MISO will use reasonable efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement.

If MISO determines that it will not meet the required time frame for completing the Optional Interconnection Study, MISO shall notify the Interconnection Customer regarding:

i. The schedule status of the Optional Interconnection Study,
ii. An estimated completion date and an explanation of the reasons why additional time is required, and
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised.



Ref	Description	Refund	<6 MW	≥6 but ≤20 MW	> 20 but ≤50 MW	> 50 but ≤100 MW	> 100 but ≤200 MW	> 200 but ≤500 MW	> 500 but ≤1000 MW	> 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 4-2 Application Fee and Study Deposits

Application Fee (D1)

The amount of the Application Fee (D1) is five thousand dollars ($5,000) for all project sizes. The Application Fee is used to offset the cost of the Pre-Queue expenses and is non-refundable. Failure to pay the (D1) Application Fee will result in withdrawal of the Interconnection Request.

DPP Study Funding Deposit (D2)

Deposit amounts to fund the Definitive Planning Phase studies will be the same for projects in a certain MW range (i.e. < 6, 7-20 ...), which are shown in Figure 4.2 and in the Table below. The amount of the study deposit is representative of the expected costs associated with completing the study for projects in those ranges. Prior to entry into the Definitive Planning Phase, the Interconnection Customer will have to select a single POI, unless they are required by a state regulatory body to take two POIs through the study process, in which case they will have to submit study deposits for each POI. Failure to pay the (D2) DPP Study Funding deposit will result in withdrawal of the Interconnection Request.

Table 4-1: D2 Definitive Planning Phase Study Funding Deposit Amounts

D2 DPP Study Funding Deposit	
< 6 MW	$50,000
≥ 6 but ≤ 20 MW	$120,000
> 20 but ≤ 50 MW	$180,000
> 50 but ≤ 100 MW	$270,000
> 100 but ≤ 200 MW	$320,000
> 200 but ≤ 500 MW	$420,000
> 500 but < 1000 MW	$530,000
≥ 1000 MW	$640,000

Refunds of Study Deposits

For additional details of the information contained in the following paragraphs regarding withdrawals and any refunds of the (M2), (M3), and (M4) deposits, refer to Section 6.2.11 of this BPM and GIP Section 7.6.1, Section 7.6.2, and Section 7.8 of Attachment X.

If the Interconnection Customer withdraws prior to entry into DPP Phase I, then the (D2) DPP Study Funding Deposit and any (M2) DPP Entry Deposit will be refunded one hundred percent (100%). Any refunds due to the Interconnection Customer will occur once MISO has been notified of the withdrawal.

If the Interconnection Customer withdraws by the end of Decision Point I, then the (D2) DPP Study Funding Deposit will be refunded, less the actual cost of the applicable Interconnection Study performed during DPP Phase I. In addition, the (M2) DPP Entry Deposit will be refunded one hundred percent (100%). An Interconnection Customer withdrawing during DPP Phase I but before Decision Point I will be responsible for its pro rata portion of the group Interconnection Study costs for DPP Phase I. Any refunds due to the Interconnection Customer will be processed after Decision Point I. Once the Interconnection Customer pays the (M3) deposit and enters DPP Phase II, the (M2) deposit becomes at risk.

If the Interconnection Customer withdraws by the end of Decision Point II, then the (M3) Milestone will be refunded one hundred percent (100%). Any (D2) DPP Study Funding Deposit will be refunded, less the actual cost of the applicable Interconnection Study performed during DPP Phase II. An Interconnection Customer withdrawing during DPP Phase II but before Decision Point II will be responsible for its pro rata portion of the group Interconnection Study costs for DPP Phase II. Any refunds due to the Interconnection Customer will be processed after Decision Point II. Once the Interconnection Customer pays the (M4) deposit and enters DPP Phase III, the (M2), (M3), and (M4) Milestone deposits become at risk.

If the Interconnection Customer withdraws any time during DPP Phase III, and MISO determines that an Interconnection Study restudy is required, then the withdrawing Interconnection Customer will be responsible to fund all such restudies in DPP Phase III, up to the amount of any remaining study deposits. However, if MISO determines that no Interconnection Study restudy is required due to the withdrawal of the Interconnection Customers Interconnection Request, then the withdrawing Interconnection Customer will not be responsible to fund any further Interconnection Studies during DPP Phase III and MISO shall refund any unused portion of the study deposit paid to enter the Definitive Planning Phase.

4.3. Determination of Project Linkages and Potential Grouping

MISO may perform a power flow analysis and use in-house post processing tools to determine project grouping. Each project will be dispatched against the generation in the MISO footprint and a distribution factor cut-off of five percent (5%) will be used for the purpose of this analysis. All projects contributing to any common constraint will be grouped together for study. Additionally the following guidelines will be used to form a study group:

i. Group Studies will not be limited by size. Upgrades for Group Studies will be determined in incremental blocks of MW capacity. The size of each block will depend on the factors such as the constrained area, transmission voltage, Right of Way availability, room for expansion in the existing substations etc. The blocks of MW (sub-groups) will be selected based on the queue position, the impact of Generation Interconnection Requests on the limiting constraints, loading on the limiting constraint, available study work and engineering judgment.

ii. Other factors such as number/type of projects, queue position, electrical proximity of the Point of Interconnections as determined in the Feasibility Study, etc. will be considered when defining a study group

4.4. Queue Position

The Initial Queue Position for the Definitive Planning Phase will be based on the date and time that the Interconnection Customer satisfies all of the requirements to enter the Definitive Planning Phase cycle. MISO will record the dates Milestones are received for each project. Within a study group, the queue positions for projects will be determined based on the date they met the last Milestone in the process. The queue position will be used to determine the cost responsibility of Network Upgrades for a project, except if the project was part of a Group Study, in which case cost responsibility will be determined according to Section 6.1.1.1.8 of this Business Practices Manual.

4.5. Applicable Reliability Criteria

NERC Standard FAC-002-2 requires a reliability impact assessment of a new generating facility on the transmission system, which is to be undertaken and results coordinated with Transmission Owners, Load Serving Entities, Transmission Providers, and other Affected Systems. Attachment FF of the Tariff provides that the Transmission Provider shall evaluate the transmission system to address Transmission Issues to meet applicable planning criteria, including accepted NERC reliability standards, reliability standards adopted by Regional Entities, local transmission planning criteria of the Transmission Owner, transmission planning criteria required by State or local authorities, and any Applicable Laws and Regulations.

To ensure compliance with the latest NERC reliability standards, Attachment FF of the Tariff, FERC Form 715, and additional Applicable Laws and Regulations, all applicable Regional, sub-Regional, and individual system local transmission planning criteria will be used to ensure that the assessment includes steady state, short circuit, and dynamic studies as necessary to evaluate system performance under both normal and contingency conditions. The Transmission Provider, in applying the local transmission planning criteria, will comply with the Tariff, ISO Agreement and applicable FERC orders governing the provision of access to and use of the Transmission System on terms that are open, transparent, comparable, and not unduly discriminatory.

4.5.1. Applicable Transmission Owner Planning Criteria - General

Transmission Owner has the exclusive authority to establish and modify its local transmission planning criteria at any time. Annually, the Transmission Owner files updates to its local transmission planning criteria as part of the FERC Form 715 filing. In addition, whenever the Transmission Owner updates its local transmission planning criteria, the Transmission Owner provides the updated local transmission planning criteria to MISO sufficiently in advance of when the Transmission Owner intends for it to be effective to enable MISO to evaluate the potential impacts of such modifications on pending interconnection requests and their relationship to other Tariff processes in order to facilitate the Transmission Providers obligations to provide transmission access on a non-discriminatory basis. As the Transmission Provider, MISO will post the new transmission owner criteria on the Planning page of the MISO website or provide a link to the Transmission Owner's web site. Concurrently, MISO will post a notice on the Planning page of MISO's web site indicating MISO has received updated local transmission owners' planning criteria.

The following describes the process for Transmission Owners to update their Local Planning Criteria and when those updates will be used in planning studies:

i. The effective date of the Transmission Owner's local transmission planning criteria will be the date that the Transmission Owner submits revised criteria to MISO. The Transmission Owner should use best efforts in notifying MISO that the Transmission Owner is in the process of modifying its local transmission planning criteria 30 days or more, prior to when the Transmission Owner expects to submit the modified criteria to MISO.
ii. The Transmission Owner's local transmission planning criteria in effect prior to the (M2) Milestone deadline will be applied to the immediate DPP cycle. Modified local transmission planning criteria in effect after the (M2) Milestone deadline, but before the beginning of a DPP System Impact Study phase, will be reviewed on a case-by-case basis as to whether it will be applied to the immediate DPP study phase. Modified local transmission planning criteria submitted after the start date of the DPP

study phase will not be applied to the immediate or ongoing DPP System Impact Study phase but will be applied to subsequent DPP cycles and may be applied to the subsequent DPP System Impact Study phase, on a case-by-case basis. However, if the immediate DPP System Impact Study undergoes a restudy and the modified local transmission planning criteria is submitted prior to the start of the restudy, the modified local transmission planning criteria will be reviewed on a case-by-case basis as to whether it will be applied to the restudy of the immediate DPP cycle.

iii. MISO will coordinate with the Transmission Owner when necessary to understand newly posted local transmission planning criteria so that MISO is able to apply the criteria.

iv. MISO will inform, in writing, the projects/requests to which newly posted local transmission planning criteria will be applied in accordance with i, ii, and iii of this section.

In the event that a modification to a Transmission Owner local transmission planning criteria conflicts with any provisions of an established MISO Business Practice Manual, in addition to the process in this section, MISO will work directly with the Transmission Owner to discuss and attempt to resolve the differences. If necessary, MISO will convene the applicable MISO stakeholder forum to address the necessary modifications to the Business Practice to enable consistency with the specific Transmission Owner modification to local transmission planning criteria.

5. Definitive Planning Phase

All Definitive Planning Entry Milestones (M1 and M2) and the DPP Study Funding deposit (D2) must be met no later than forty-five (45) Calendar Days prior to the start of the next Definitive Planning Phase cycle. These Milestones and deposits have been described in Section 4.2.1, 4.2.2 and 4.2.5 respectively. MISO will conduct two Definitive Planning Phase cycles every year. Each Definitive Planning Phase (DPP) cycle will consist of three (3) DPP Phases, as described in the following sections. MISO will utilize Reasonable Efforts to complete the DPP cycle within three hundred fifty-five (355) Calendar Days.

An overview of the Definitive Planning Phase is shown in Figure 5-1 on the following page.

Generator Interconnection Process

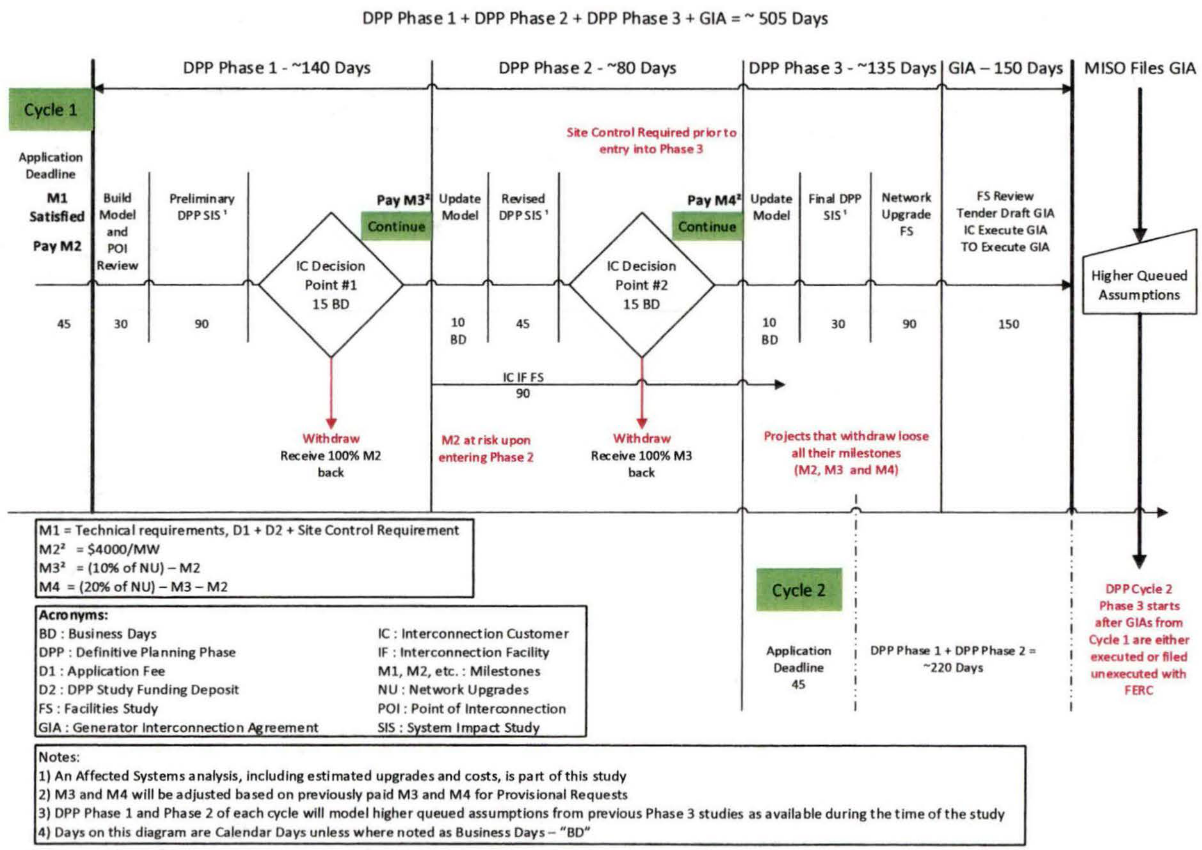


Figure 5-1 Overview of Definitive Planning Phase

5.1. Definitive Planning Phase Entry

When the Interconnection Customer satisfies the (M1) requirements and provides the (D1) Application Fee, (D2) DPP Study Funding deposit, and the (M2) DPP Entry Milestone deposit at least forty-five (45) Calendar Days prior to the start of the DPP, the Interconnection Request will be placed in Definitive Planning Phase I. The project will enter into the DPP as described in the following sections, providing the deliverables for each phase. Details of each of the DPP processes and methodologies are discussed in Section 6 below. If the Interconnection Customer elects not to meet the (M1) requirements and the (M2) Milestone deposit the project will be considered withdrawn.

5.2. Definitive Planning Phase I

The Definitive Planning Phase I will start on a defined, periodic basis. Phase I of the DPP is designed to provide the Interconnection Customer with a preliminary detailed analysis of their Interconnection Request's impact on the reliability of the Transmission System and will be approximately one hundred forty (140) Calendar Days in length. During this phase MISO will perform the initial Model Building and Review, which is scheduled for thirty (30) Calendar Days. Following this, a preliminary Interconnection System Impact Study and preliminary Affected System analysis including estimated upgrades and costs, as applicable, will be performed and is scheduled for ninety (90) Calendar Days. Once the analysis is done, the Interconnection Customer will enter into Interconnection Customer Decision Point I, which will last fifteen (15) Business Days.

5.2.1. Model Building and System Impact Study

Prior to starting the preliminary System Impact Study, MISO will distribute the study models to the Interconnection Customer and the Transmission Owner. The Interconnection Customer and the Transmission Owner may recommend changes to the study model by providing a completed Interconnection Study Model Review Form, Appendix 10 to the GIP within ten (10) Business Days after receipt of the study models. The proposed changes will be incorporated into the study models after mutual agreement on the changes by MISO, the Interconnection Customer, and the Transmission Owner, such agreement not to be unreasonably withheld. The preliminary System Impact Study will begin after agreement has been reached and the changes have been incorporated into the model, or by the end of the allotted thirty (30) Calendar Days set aside for this process. Failure of the Interconnection Customer to provide a completed Interconnection Study Model Review Form within ten (10) Business Days of receipt of the study models will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of the GIP.

5.2.2. Delays to Phase I Timeline

At the request of the Interconnection Customer, or at any time MISO determines that it will not meet the required time frame for completing the preliminary Interconnection System Impact Study, MISO shall notify the Interconnection Customer regarding:

i. The schedule status of the preliminary Interconnection System Impact Study
ii. An estimated completion date and an explanation of the reasons why additional time is required
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the Interconnection Customer must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the Interconnection Customer to provide this additional deposit will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of the GIP.

5.2.3. Interconnection Customer Decision Point I

Once the preliminary System Impact Study and preliminary Affected System analysis including estimated upgrades and costs, as applicable, is delivered, the Interconnection Customer will pass through the Interconnection Customer Decision Point I. The Interconnection Customer Decision Point I will last for fifteen (15) Business Days and the Interconnection Customer can either proceed to Definitive Planning Phase II or withdraw its Interconnection Request. During the Interconnection Customer Decision Point I, the Interconnection Customer may reduce the size of its Interconnection Request by as much as one hundred percent (100%), but the required Definitive Planning Phase II Milestone (M3) calculation will be based on the Definitive Planning Phase I results. If the Interconnection Customer decides to withdraw its Interconnection Request during, or at any time before the end of the Interconnection Customer Decision Point I, then pursuant to Section 7.6 of the GIP, MISO will refund the Interconnection Customer with the Definitive Planning Phase I Milestone (M2) and any remaining study deposits. If the Interconnection Customer decides to proceed to the Definitive Planning Phase II, then it will be required to pay the Definitive Planning Phase II Milestone (M3), pursuant to Section 7.3.1.4.1 of the GIP.

5.2.4. The (M3) Milestone Calculation

The Definitive Planning Phase II Milestone (M3) will be calculated as ten percent (10%) of the amount of Network Upgrades identified in the DPP Phase I System Impact Study less the amount previously provided at (M2), but in no event shall (M3) be less than zero dollars.

Network Upgrades are all of the upgrades identified on the MISO system. Network Upgrades do not include Interconnection Facilities or Affected System (external to MISO) upgrades. The (M3) Milestone will be in the form of either cash or irrevocable letter of credit reasonably acceptable to the Transmission Provider and must be received prior to the start of Definitive Planning Phase II.

5.2.5. Withdrawal from DPP Phase I

If MISO does not receive written confirmation from the Interconnection Customer regarding whether it wants to proceed to the Definitive Planning Phase II or withdraw its Interconnection Request, during the Interconnection Customer Decision Point I, MISO will deem the Interconnection Request as withdrawn. After the Interconnection Customer enters the Definitive Planning Phase II, the Definitive Planning Phase I (M2) Milestone payment becomes one hundred percent (100%) non-refundable, pursuant to Section 7.6.2 of the GIP.

5.3. Definitive Planning Phase II

The Definitive Planning Phase II will start the next day after the fifteen (15) Business Days Interconnection Customer Decision Point I window expires. Phase II of the Definitive Planning Phase is to designed to provide the Interconnection Customer a revised and detailed analysis of their Interconnection Project's impact on the reliability of the Transmission System after incorporating updated generation assumptions resulting from the withdrawal of Interconnection Requests during Definitive Planning Phase I, and will be approximately eighty (80) Calendar Days in length. MISO will perform an update to the Model Building and Review results done in Definitive Planning Phase I, scheduled for ten (10) Business Days. Following this, MISO will conduct a revised System Impact Study, scheduled for forty-five (45) Calendar Days. At the beginning of the Definitive Planning Phase II, MISO will also conduct the Interconnection Facilities Study, scheduled for ninety (90) Calendar Days.

5.3.1. Revised Model Building and Revised System Impact Study

Prior to starting the revised System Impact Study, MISO will update the study models built during Phase I by removing all the Interconnection Requests that did not proceed to the Definitive Planning Phase II. MISO will distribute the study models to the Interconnection Customer and the Transmission Owner for final review. Any comments or corrections from the Transmission Owner or Interconnection Customer to the revised study models must be submitted to MISO within five (5) Business Days after receipt of the revised study models. Should the Transmission Owner or the Interconnection Customer fail to provide feedback on the revised study models within five (5) Business Days after receipt of the revised study models, MISO shall deem the models acceptable. After this point, the revised System Impact Study can begin.

5.3.2. Delays to Phase II Timeline

At the request of the Interconnection Customer, or at any time MISO determines that it will not meet the required time frame for completing the revised Interconnection System Impact Study, MISO shall notify the Interconnection Customer regarding:

i. The schedule status of the revised Interconnection System Impact Study
ii. An estimated completion date and an explanation of the reasons why additional time is required
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the Interconnection Customer must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the Interconnection Customer to provide this additional deposit will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of the GIP.

5.3.3. Interconnection Customer Decision Point II

Once the revised System Impact Study and revised Affected System analysis, including estimated upgrades and costs, is delivered, the Interconnection Customer will pass through the Interconnection Customer Decision Point II. The Interconnection Customer Decision Point II will last for fifteen (15) Business Days, and the Interconnection Customer can either proceed to Definitive Planning Phase III or withdraw its Interconnection Request. During the Interconnection Customer Decision Point II, the Interconnection Customer may reduce the size of its Interconnection Request by as much as ten percent (10%), but the (M4) Milestone calculation will be based on the Definitive Planning Phase II results. If the Interconnection Customer decides to proceed to the Definitive Planning Phase III, then it will be required to pay the Definitive Planning Phase III Milestone (M4), pursuant to Section 7.3.1.4.1 of the GIP, and provide reasonable evidence of Site Control prior to the end of Interconnection Customer Decision Point II. The details of the Site Control provision are in Section 4.2.1.1.1. After providing proof of Site Control, the Interconnection Customer's one hundred thousand dollar ($100,000) Site Control deposit will be refunded. Failure to provide Site Control at Interconnection Customer Decision Point II will result in the Interconnection Request to be withdrawn, and any Site Control deposit will be refunded.

5.3.4. The (M4) Milestone Calculation

The Definitive Planning Phase III Milestone (M4) will be calculated as twenty percent (20%) of the amount of Network Upgrades identified in the revised System Impact Study less the amount previously provided at (M2) and (M3), but in no event shall (M4) be less than zero dollars. The (M4) Milestone will be in the form of either cash or irrevocable letter of credit reasonably acceptable to the Transmission Provider and must be received prior to the start of Definitive Planning Phase III.

5.3.5. Withdrawal from DPP Phase II

If MISO does not receive written confirmation from the Interconnection Customer regarding whether it intends to proceed to the Definitive Planning Phase III or to withdraw its Interconnection Request during the Interconnection Customer Decision Point II, MISO will deem the Interconnection Request as withdrawn and refund the Interconnection Customers Definitive Planning Phase II Milestone (M3) and any remaining study deposits pursuant to Section 7.6 of the GIP. After the Interconnection Customer enters the Definitive Planning Phase III, the Definitive Planning Phase II (M3) Milestone payment becomes one hundred percent (100%) non-refundable, pursuant to Section 7.6.2 of the GIP.

5.3.6. Initial Interconnection Facilities Study

The first portion of the Interconnection Facilities Study will begin the first day of Definitive Planning Phase II. This portion will focus on identifying cost estimates and the time required to construct the Interconnection Facilities. MISO shall use reasonable efforts to complete this portion of the Interconnection Facilities Study within ninety (90) Calendar Days.

5.4. Definitive Planning Phase III

The Definitive Planning Phase III will start the next Business Day after the Interconnection Customer Decision Point II window expires. Phase III is designed to provide Interconnection Customers a final, detailed analysis of their Interconnection Project's impact on the reliability of the Transmission System after incorporating updated generation assumptions due to potential withdrawal of Interconnection Requests during Definitive Planning Phase II and will be approximately one hundred thirty-five (135) Calendar Days in length. MISO will perform an update to the Model Building and Review results done in Definitive Planning Phase II, scheduled for ten (10) Business Days. Following this, MISO will conduct a final System Impact Study, scheduled for thirty (30) Calendar Days. MISO will also conduct the Interconnection Facilities Study for Network Upgrades, which is scheduled for ninety (90) Calendar Days.

5.4.1. Model Updates and Final Interconnection System Impact Study

Prior to starting the final Interconnection System Impact Study, MISO will update the study models built during Phase II by removing all the Interconnection Requests that did not proceed to the Definitive Planning Phase III. MISO will distribute the study models to the Interconnection Customer and the Transmission Owner for final review. Any comments or corrections from the Transmission Owner or Interconnection Customer to the revised study models must be submitted to MISO within seven (7) Calendar Days after receipt of the revised study models. Should the Transmission Owner or the Interconnection Customer fail to provide feedback on the revised study models within seven (7) Calendar Days after receipt of the revised study models, MISO shall deem the models acceptable. After this point, the final System Impact Study can begin. Section 6.1 provides details of the System Impact Study methodologies and deliverables.

5.4.2. Delays to Phase III Final Interconnection System Impact Study Timeline

At the request of the Interconnection Customer, or at any time MISO determines that it will not meet the required time frame for completing the final Interconnection System Impact Study, MISO shall notify the Interconnection Customer regarding:

i. The schedule status of the final Interconnection System Impact Study
ii. An estimated completion date and an explanation of the reasons why additional time is required
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the Interconnection Customer must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the Interconnection Customer to provide this additional deposit will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of the GIP.

5.4.3. Final Interconnection Facilities Study

The second portion of the Interconnection Facilities Study shall start after the final Interconnection System Impact Study is complete. This study will estimate the cost and time required to build necessary Network Upgrades that are identified in the final Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facilities to the Transmission or Distribution System, as applicable, as well as that equipment, to the extent known and available in accordance with Section 3.5 of the GIP. MISO shall use reasonable efforts to complete this portion of the Interconnection Facilities Study within ninety (90) Calendar Days.

5.4.4. Delays to the Phase III Final Interconnection Facilities Study Timeline

At the request of the Interconnection Customer, or at any time MISO determines that it will not meet the required time frame for completing the final Interconnection Facilities Study, MISO shall notify the Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If MISO is unable to complete the Interconnection Facilities Study and issue a draft GIA appendices and, as applicable, associated draft appendices for the related FCA(s) and/or MPFCA(s), along with supporting documentation, within the time required, it shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. If MISO is unable to complete the Interconnection Facilities Study with the study deposit provided by the Interconnection Customer, MISO shall notify the Interconnection Customer and provide a revised cost estimate with an explanation of the reasons why. The Interconnection Customer shall provide an additional deposit equal to the difference between the initial and revised cost estimate within fifteen (15) Calendar Days of MISO's notice. Failure of the Interconnection Customer to provide this additional deposit will result in the withdrawal of the Interconnection Request pursuant to Section 3.6 of the GIP.

5.4.5. Facilities Studies

The Interconnection Customer and Transmission Owner may, within fifteen (15) Calendar Days after receipt of the draft Interconnection Facilities report, which information will be incorporated into the GIA appendices, and, as applicable, associated draft appendices for the related FCA(s) and/or MPFCA(s) and supporting documentation, provide written comments to be included in the final Interconnection Facilities report. As described above, MISO shall issue the final Interconnection Facility Study within ten (10) Calendar Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's statement that it will not provide comments. MISO may reasonably extend the fifteen (15) Calendar Days period upon notice to the Interconnection Customer if the Interconnection Customer's comments require MISO to perform additional analysis or make other significant revisions prior to the issuance of the final Interconnection Facilities Study report. Upon request, MISO shall provide the Interconnection Customer with supporting documentation, work papers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements provided in Section 13.1 of the GIP.

Within ten (10) Business Days of providing the draft Interconnection Facilities Study report and supporting documentation to the Interconnection Customer, MISO and the Interconnection Customer may meet to discuss the results of the Interconnection Facilities Study.

5.4.6. Interconnection Study Restudy

If MISO determines restudy is required because one of the contingencies in Article 11.3.1 of the GIA has occurred, or at MISO's discretion, MISO will reevaluate the need for the Common Use Upgrade and/or Shared Network Upgrade, and if still required, reallocate the cost and responsibility for any Common Use Upgrade and/or Shared Network Upgrade, without a restudy when possible, or with a restudy if MISO deems it necessary in order to ensure reliability of the Transmission System.

If a restudy of any Interconnection Study is required because an Interconnection Request withdraws or is deemed to have withdrawn prior to all GIAs, FCAs, and/or MPFCAs, as applicable, for each respective Definitive Planning Phase cycle have been executed or filed unexecuted with the Federal Energy Regulatory Commission, MISO shall provide notice of a restudy as necessary. MISO will include in the notice of restudy a preliminary analysis supporting the need for an Interconnection Study restudy, an explanation of why an Interconnection Study restudy is required, and a good faith estimate of the cost to perform the Interconnection Study restudy. The Interconnection Study restudy will be performed according to the GIP and the Business Practice Manuals in effect at the time the notice is given by MISO. The Interconnection Customer shall notify MISO within five (5) Business Days whether the Interconnection Customer wishes to proceed with the Interconnection Study restudy or withdraw its Interconnection Request. MISO will deem a failure to notify MISO to proceed to perform the Interconnection Study restudy as the Interconnection Customers withdrawal of its Interconnection Request in accordance with Section 3.6 of the GIP. MISO will use reasonable efforts to complete the Interconnection Study restudy within sixty (60) Calendar Days from the date of notice. MISO may perform the Interconnection Study restudy of Network Upgrades common to more than one Interconnection Request as a Group Study.

6. Definitive Planning Phase Processes and Methodologies

6.1. Generator Interconnection System Impact Study

A System Impact Study (SIS) will be conducted which will include thermal analysis, short circuit analysis, transient and voltage stability analysis. The System Impact Study will provide a list of facilities (including Interconnection Facilities, Network Upgrades, Distribution Upgrades, Generator Upgrades, Common Use Upgrades, Shared Network Upgrades, and, if such upgrades have been determined, upgrades on Affected Systems) that are required as a result of the Interconnection Request. The study may also include system protection, and loss analyses depending on the recommendation from the ad hoc group. SIS results will include a preliminary indication of the planning level estimate of cost and length of time that would be necessary to implement any Network Upgrades identified in the analysis. The Network Upgrades may be identified to accommodate a group of generators together, wherever applicable.

6.1.1. Steady State Analysis

The Steady State Analysis will include the evaluation of system performance under both normal and contingency conditions for all new generation Interconnection Requests, including energy storage devices, in accordance with Reliability TPL Standards. The Steady State Analysis will generally include the following analyses:

i. Thermal analysis
ii. Voltage analysis
iii. Power factor requirement analysis
iv. Prior outage analysis

For Interconnection Requests related to energy storage devices, MISO will evaluate the plant for an entire range of operation by testing the plant as a generator and a load.

6.1.1.1 Thermal analysis

Steady State Thermal analysis will be performed by adhering to all applicable standards as discussed in 0. A new ad hoc study group will be formed and chaired by MISO for each study. MISO will determine, with input from the ad hoc group, the monitored element and contingency list and other study assumptions. Based on the recommendations and input received from the ad hoc group, facilities in the Affected System that could potentially be impacted by the interconnection are monitored. For any identified significantly affected facility, the study will determine upgrades and costs required to mitigate the constraints for full power output.

The bench case (pre-project case) will be created by considering the most recent MTEP 5 year out LBA dispatch case as the starting case. The higher queued generators (without a GIA) shall be added to the bench case and shall be dispatched at their expected output level as per fuel type such that generators in MISO North (Classic) are sunk into MISO North (Classic) and generators in MISO South are sunk into MISO South[1]. The study case (post-project case) will be created by adding the study generator(s) and associated interconnection facilities to the Base Case. The study generator(s) shall be turned on at their expected output level described in Section 6.1.1.1.1.1 and dispatched against other units across MISO North or MISO South region as described above. The post case will undergo a DC screen to identify monitored element and contingency pairs which are significantly loaded (e.g. ninety percent (90%) or more). The loadings will be recorded for the post and Base Cases and distribution factors will be calculated by using the Monitored Sensitivity function in PSS MUST. All monitored element and contingency pairs which are overloaded (worst case loading) in the post case using AC analysis and which meets the criteria in Section 6.1.1.1.6 will be reported.

To mitigate a constraint, MISO will check the MTEP appendices and discuss with the impacted Transmission Owner(s) to determine if there already exists a planned project which will alleviate the constraint. If there is no such planned or proposed project, MISO will work with the impacted Transmission Owner(s) and Interconnection Customers to identify a prudent transmission upgrade based on Good Utility Practices. If a transmission project(s) resolves the constraint, and that project(s) is approved by the Board within (1) calendar year of the Generator Interconnection Agreement (GIA) execution or execution of an amendment thereof, then the Interconnection Customer will not be responsible for transmission upgrade(s) that would resolve the constraint. If that project(s) is not approved within one (1) calendar year of the Generation Interconnection Agreement (GIA) execution or execution of an amendment thereof, the Interconnection Customer will be responsible for those transmission upgrade(s).

6.1.1.1.1 Base Case Assumptions

The Base Cases for a System Impact Study in the new DPP study will be the most recent Summer Peak and Shoulder Peak (high wind scenario: wind at 90%) MTEP 5 year out LBA dispatch cases wherein dispatch of existing generators and new generators with signed Generator Interconnection Agreement (GIA) will not be modified. The Base Cases will be

[1] After dispatching generators per fuel type, the total generation in MISO North (Classic) and MISO South shall be equal to total generation in the respective region as seen in the starting MTEP case. This ensures that the total load & losses in a region are being served by total generation in the respective region and thereby implicitly respecting the N-S constraint/transfer limit.

updated to include only those projects in the queue that have a DPP Queue Position with their associated Network Upgrades. Any approved transmission projects (in MTEP Appendix A) and projects recommended by MISO for board approval (e.g. recommended short-term Transmission Plan defined in BPM 20) will be included in the Base Cases.

6.1.1.1.1.1 Study Case Development

The ERIS Study Cases will be created for power flow analysis for the near-term (5 year out) Summer Peak and Shoulder Peak scenarios by dispatching the higher queued generators (without a GIA) and the study generators to the MISO footprint as per Table 6-1.

Table 6-1 Dispatch per Fuel Type for Study and Higher Queued Generators (without a GIA)

Fuel Type under Study and Higher Queued	Summer Peak Dispatched as % of Nameplate	Shoulder Peak Dispatched as % of Nameplate
Combined Cycle	100%	50%
Combustion Turbine	100%	0%
Diesel Engines	100%	0%
Hydro	100%	100%
Nuclear	100%	100%
Pumped Storage[2]	+/- 100%	+/- 100%
Steam – Coal	100%	100%
Oil	100%	0%
Waste Heat	100%	100%
Wind	15.6%[3]	100%
Solar	100%	50%[4]
Battery[5]	+/- 100%	+/- 100%

Any other seasonal model with appropriate load and generation dispatch level, if required to adequately assess the system reliability in the region, may replace one or more of the cases listed above.

[2] Pumped Storage plants will also be evaluated for load interconnection
[3] Dispatch level for wind resources will be aligned with wind capacity credit used in the MTEP summer peak case. It is 15.6% in 2017 MTEP summer peak case.
[4] Dispatch level for solar resources will be aligned with solar dispatch in the MTEP shoulder peak case. It is 50% in 2017 MTEP shoulder peak case.
[5] Battery plants will also be evaluated for load interconnection

6.1.1.1.1.2 Generation to Include

The System Impact Study Base Case will include the following queued generation projects, including energy storage devices, in the region:

i. All projects with a Generation Interconnection Agreement (GIA); generators with provisional GIAs will be included only if they meet criteria ii) below.
ii. All projects that have a DPP Queue Position and their associated Network Upgrades.
iii. All queued projects on the Affected System (in the Generator Interconnection queue of the other Transmission or Distribution Providers) will be modeled per MISO and Affected System joint agreements.

Generators requesting Retirement or Suspension under MISO Attachment Y process are notified about their approval by a letter from MISO upon completion of the necessary studies. Such generators will be treated as follows:

i. Generators under study will be modeled available for dispatch up to their interconnection service level.
ii. Generators approved for Suspension or designated as System Support Resources (SSR) for Suspension period will be modeled available for dispatch up to their interconnection service level.
iii. Generators approved for Retirement will be modeled available for dispatch up to their interconnection service level until the date the generator is approved to retire as specified in the Attachment Y Notice
iv. Generators requesting Retirement but designated as System Support Resources (SSR) will be modeled available for dispatch up to their interconnection service level until the latest in-service date of system improvements necessary to ensure system reliability as listed in the Attachment Y study report

6.1.1.1.2 Applicable Reliability Criteria

FAC-002-2 standard requires a reliability impact assessment of new generating facility, on the transmission system, to be undertaken and results coordinated with Transmission Owners, Load Serving Entities, Transmission Providers other Affected Systems. To ensure compliance with NERC reliability standard FAC-002-2, all applicable Regional, sub-regional, Power Pool and individual system local transmission planning criteria will be used to ensure that the assessment includes steady state, short circuit, and dynamic studies as necessary to evaluate system performance under both normal and contingency conditions[6] in accordance with reliability TPL standards.

All applicable NERC TPL and FAC standards can be referenced at the following link: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf

6.1.1.1.3 Cascading Outage Conditions

Based on the ad hoc group's recommendation, select events may be studied to identify potential cascading outage conditions. After taking appropriate NERC/ERO/Regional action, including the controlled reduction of generation, load and curtailing firm transfers, if the transmission facility is still overloaded, then additional upgrades may be required to alleviate the condition (Refer to section 6.1.1.1.2 for details pertaining to applicable reliability criteria).

6.1.1.1.4 Prior Outage Conditions

Based on the ad hoc group's recommendation, and in compliance with 6.1.1.1.2, contingency analysis in the local area will be performed for selected prior outage conditions. The purpose of this review is to identify operating restrictions or additional Network Upgrades to prevent unreliable operating conditions under prior outage conditions. In the event that Special Protection Systems (SPS) or an operating plan cannot be developed to prevent cascading uncontrolled outages, either a permanent reduction in generation (i.e., a relay scheme that trips the synchronizing breaker past a certain MW level) or a Network Upgrade may be identified.

The output of this study will be an appendix to the Interconnection System Impact Study report. Also, the results of this study may be included in the operating sections of the appendices to the Interconnection and Operating Agreement.

6.1.1.1.5 Permissible Software Tools

Siemens PTI's PSS/E and PSS MUST software for power system studies will be used to perform the studies. MISO will use in-house software tools in conjunction with PSS/E and PSS MUST to generate and post-process the study results. MISO may consider using other industry accepted power system analysis software tools with similar capabilities.

[6] The System Impact Study includes only select contingencies, based on inputs from the ad-hoc study group, for which system adjustments are permitted as per the TPL standards.

6.1.1.1.6 Criteria Used to Determine Constraints

In order to obtain any type of Interconnection Service, all generators, including energy storage devices, must mitigate injection constraints identified in the study. A constraint is identified as an injection constraint if:

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

Further, the Generating Facilities, including energy storage devices, requesting Network Resource Interconnection Service must mitigate constraints under system intact and single contingency conditions, by using the deliverability algorithm, if the generator impact (incremental flow caused by the generator) is equal to or greater than five percent (5%) of the net injected power into the grid.

Mitigations for a NERC TPL multiple contingency events will be determined in accordance with reliability criteria identified in 6.1.1.1.2. Engineering judgment may be used for special cases.

6.1.1.1.7 Deliverability Analysis

For the purpose of Deliverability Analysis, impacts of higher queued or pre-existing requests for Energy Resource Interconnection Service (ERIS) will not be considered unless they have a confirmed firm transmission service reservation associated with the generator. In that case, only the level of firm transmission service will be modeled in the Base Case when studying a lower queued project for deliverability. Network Resource Interconnection Service (NRIS) will be evaluated at one hundred percent (100%) of the requested capability of the Interconnection Request, including those for energy storage devices. The NRIS will be granted for the amount for which a generator commits to build the Network Upgrades, up to the requested capability of the Interconnection Request, as identified through the deliverability analysis. The Interconnection Customer must choose the NRIS level prior to the start of the Network Upgrade Facility Studies phase. Once the Interconnection Customer chooses a NRIS MW level, that MW amount will be used in the Network Upgrade Facilities Study and be included in the GIA. The Interconnection Customer will not be allowed to downgrade the Interconnection Service after the start of the Network Upgrade Facilities Study.

The methodology for deliverability analysis can be found in a whitepaper posted on the MISO website:
https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/ActiveStudyReportsandPolicyStatements.aspx

6.1.1.1.8 Network Upgrade Cost Allocation

The Network Upgrades cost for a set of projects (one or more sub-groups or entire group with identified Network Upgrades) will be allocated based on the MW impact from each project on the constrained facilities in the Post Case. With all such projects in the Base Case, all thermal constraints will be identified and a distribution factor from each project, including energy storage devices, on each constraint will be obtained. Finally, the cost will be allocated based on the pro rata share of the MW contribution on all constraints from each project, including energy storage devices.

The following table provides a simplistic example of the cost allocation methodology described in this section.

Table 6-2 Example of Project Cost Allocation Methodology

Constraint	MW contribution from Project x	MW contribution from Project y	MW contribution from Project z
c1	x1	y1	z1
c2	x2	y2	z2
c3	x3	y3	z3
Cn	Xn	Yn	Zn
Total MW contribution on constrained facilities from project x equals: X = x1+x2+x3+…+xn			
Total MW contribution on constrained facilities from project y equals: Y = y1+y2+y3+…+yn			
Total MW contribution on constrained facilities from project z equals: Z = z1+z2+z3+…+zn			
Total MW flowing on all constraints from Group Study projects = X+Y+Z			
Project x's share on the total NU cost = X/(X+Y+Z) Project y's share on the total NU cost = Y/(X+Y+Z) Project z's share on the total NU cost = Z/(X+Y+Z)			

Note that the allocation is applicable to the Network Upgrade cost only; each project will be responsible for the cost of Interconnection Facilities required to connect to the Transmission System. In order to save time and effort a more simplistic approach can be used for the purpose of cost allocation as long as the new method is acceptable to all parties and does not delay the study process.

6.1.1.1.9 Shared Network Upgrade Cost Allocation Eligibility

The Shared Network Upgrades are the Network Upgrades funded by an Interconnection Customer that are or will be in-service prior to the Commercial Operation date submitted by the Interconnection Request under study, or are otherwise far enough along that it is not practical to bring the Interconnection Request under study into an MPFCA for the upgrade.

As part of the System Impact Study MISO will review the proposed configuration of the study generators, including energy storage devices, and perform a test, if required, to determine their eligibility for cost sharing. The set of Shared Network Upgrades included in the test will be all GIP facilities identified after July 15, 2010 and in-service for a period of less than five (5) years.

If a generator meets any of the following two criteria, it will share the cost of the Shared Network Upgrade without any further tests:

i. The generator connects to the Shared Network Upgrades
ii. The generator connects to a substation where the Shared Network Upgrade(s) terminates

For all other generators that do not meet the above criteria, further analysis will be performed to measure their use of and benefit from the Network Upgrades previously identified and funded by other generators. The intent of the test is to determine if the new generators under study are benefiting from a Network Upgrade previously identified for a different generator and should share in the cost of that Network Upgrade.

A power flow analysis will be performed to calculate the impacts of the study generators on the Shared Network Upgrades under system-intact conditions. The following two screening criteria will be used to make the decision

i. If the impact of the Interconnection Request on a generator funded Network Upgrade is greater than 5MW AND is greater than one percent (1%) of the facility rating, the following additional screening will be performed
ii. If the impact of the Interconnection Request on a generator funded Network Upgrade is greater than five percent (5%) of the facility rating OR the power transfer distribution factor (PTDF) is greater than twenty percent (20%), the generator will share the cost of the Network Upgrade, now designated as a Shared Network Upgrade.

The flowchart in Figure 6-1 visually describes the whole methodology for determining the eligibility for cost sharing. The Shared Network Upgrades the new generator is responsible for will be listed in Appendix A of their GIA.

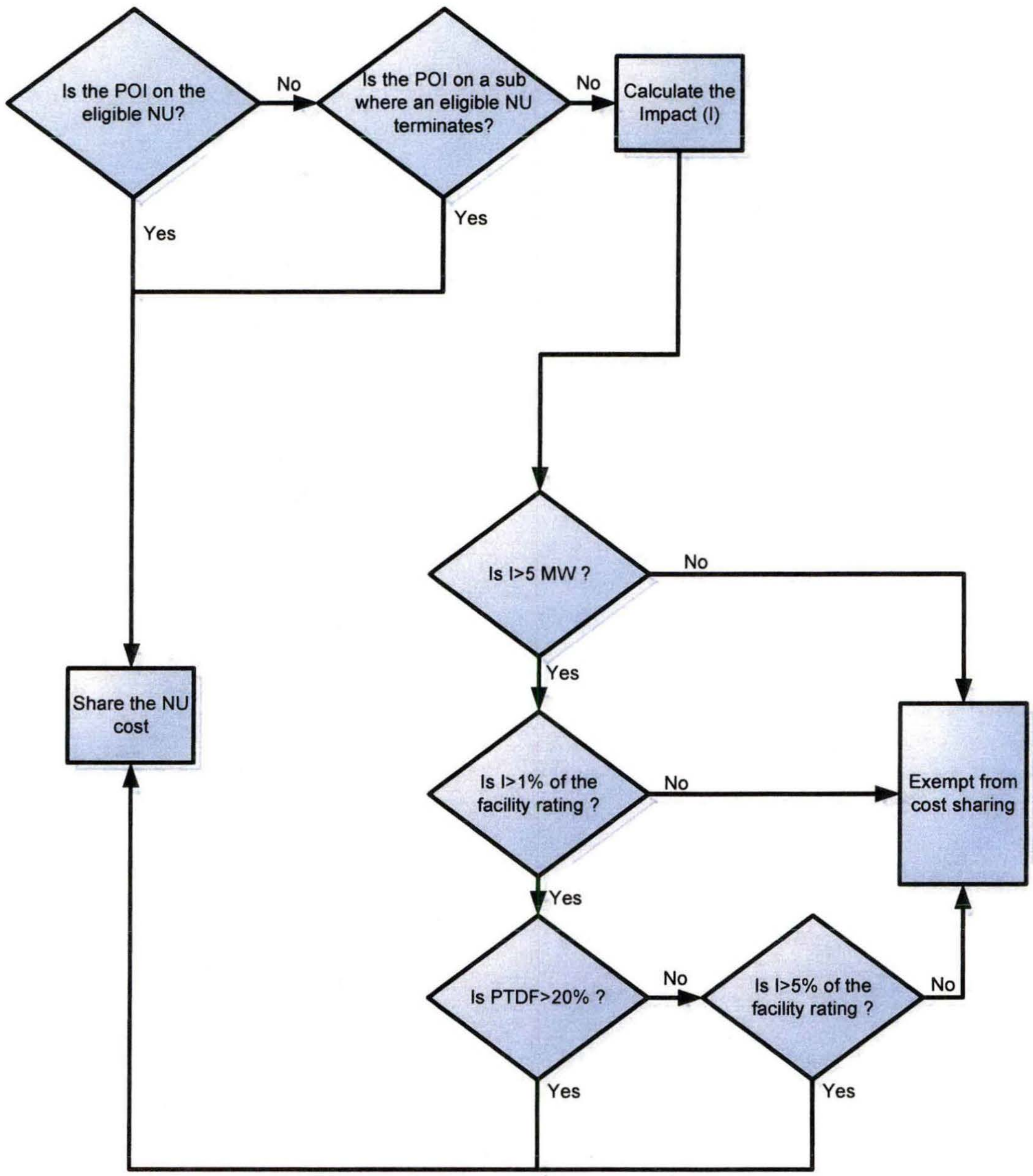


Figure 6-1 Flowchart describing the methodology to identify the Late Comer projects

6.1.1.2 Steady State Voltage Analysis

Voltage analysis will be performed on the selected contingencies generated from the DC screen or contingencies deemed relevant to the analysis. Bus voltages outside of the defined limits (based on the Local Balancing Authority criteria) in the post case will be recorded and compared to the Base Case values. Bus voltages will be considered voltage constraints if, for a given contingency, the bus voltage is outside of the allowed voltage range for the post case and is at least 0.01 per unit worse than the Base Case voltage for the same contingency.

6.1.1.3 Power Factor Requirement and Low Voltage Ride Through Analysis for Wind Generation Plants

Power Factor (PF) and Low Voltage Ride Through (LVRT) analysis will be performed to determine the requirements for a new Wind Generation Plant according to FERC Orders 661/661-A, FERC Order 827, and Appendix G of the pro forma GIA. MISO will use the following methodology in determining the final requirements as determined during the System Impact Study.

i. To determine the PF requirements for a Wind Generation Plant, MISO will model each Wind Generation Plant under study at unity PF at the Point of Interconnection ("POI") (no reactive capability). If voltage criteria violations at the POI exist, then MISO will enforce the criteria laid out in FERC Orders 661/661-A, thereby modeling the plant at the more stringent of 0.95 leading and lagging PF capability at the POI or the Transmission Owners interconnection guidelines PF requirements. Should no voltage criteria violations exist, MISO will model the inherent capability of the Turbines at the POI using the best available Interconnection Customer supplied data, and proceed with studies.
ii. For a new Generating Facility, MISO will request the Interconnection Customer to demonstrate compliance with the FERC Order 827 requirement. The associated modeling will be applied in the study model.
iii. A Wind Generation Plant must be able to remain online during select system disturbances. To test the LVRT capability of a Wind Generation Plant, MISO will evaluate the plants' performance for the following faults:
    a. Three phase faults with normal clearing
    b. Single Line to Ground faults with delayed clearing

If violations are found, the Interconnection Customer will be required to submit updated LVRT settings to ensure that the LVRT threshold is maintained at the POI. The Wind Generating Plant will be required to remain online for the specified time intervals.

6.1.2. Short Circuit and Stability Analysis

Short circuit analysis will generally include determining the fault current contribution from the new Generating Facility and its Network Upgrades under three-phase fault and single line to ground fault conditions. The study will identify any circuit breaker that would need to be replaced to accommodate fault currents from the proposed Generating Facility.

The stability study will include the evaluation of the impact of the new Generating Facility on transient stability performance of the system by adhering to the reliability standards under 6.1.1.1.2. The stability study may also consider other scenarios to assess system transient stability in accordance with the local transmission planning criteria and Section 4.5 of this BPM.

Additionally, based on engineering judgement, MISO may include other scenarios to assess system transient stability when all generators in the same electrical area (local area) as the study generator(s) are at their full ERIS level. The Interconnection Customer will only be responsible for mitigating constraints which are caused by the study generators.

Example:

> The **base case** used for the stability study will be dispatched with all generators local to the study generator(s) to their full ERIS injection capacity.
>
> The **study case** will be created by adding the study generator(s) to the base case.
>
> The Interconnection Customer will only be responsible for constraints which appear in the study case but do not appear in the base case.

For wind turbine generators LVRT analysis would be done according to FERC Orders 661 and 661-a.

6.1.2.1 Base Case Assumptions

6.1.2.1.1 Load Levels

The Stability Study will be performed using a season and load level that traditionally represents most limiting conditions for system stability in the region.

6.1.2.1.2 Generation to Include

Refer to Section 6.1.1.1.1.2.

For the short circuit analysis, queued generation will be added only in the area close to where the proposed generation is being added. Since the fault current contribution from a generator decays quickly the deeper you go into the system, the network changes electrically remote from the POI may be ignored for the purpose of short circuit analysis.

6.1.2.2 Applicable Reliability Criteria

Refer to Section 6.1.1.1.2.

6.1.2.3 Permissible Software Tools

Siemens PTI's PSS/E software for power system studies will be used to perform the studies. MISO may use the in-house software tools/scripts or regionally accepted software programs to generate the results with PSS/E and post-process them. MISO may consider using other industry accepted power system analysis software tools with similar capabilities.

For short circuit analysis, PSS/E, Aspen, CAPE or any other industry accepted software tools with similar capabilities may be used.

6.1.2.4 Criteria Used to Determine Stability and Short Circuit Constraints

Stability Study

All conditions/disturbances leading to the Generating Facility or system instability in compliance with the applicable reliability standards in 6.1.1.1.2 will be documented as a constraint. If there is regional or Transmission Owner's FERC filed planning criteria for transient period voltages or post transient voltage recovery, it will be monitored and any violation caused by the proposed interconnection will be flagged as a constraint.

Short Circuit Study

All breakers over-dutied (underrated) after the addition of the proposed Generating Facility will be flagged.

6.1.2.5 Mitigation Used to Resolve Stability Constraints

MISO will coordinate and seek feedback from the ad-hoc group to identify and implement appropriate mitigation recommendations, for observed criteria violation in 6.1.2.4. This mitigation may include, but not limited to, the transmission reinforcement, faster breakers, new breakers, additional static or dynamic reactive support, an operating guide or special protection scheme depending on the type of disturbance causing the constraint.

6.1.3. Mitigation Verification

Sensitivity analyses will be performed by modeling Network Upgrades identified in all System Impact Study analyses to verify that the recommended mitigation does not cause any new reliability violations. If it is determined that the coordinated and recommended mitigation plan causes further reliability violations on the transmission system, then the Interconnection Customer will be provided various alternatives as follows.

i. Interconnection Customer can agree to fund these additional upgrades and proceed to the Facilities phase of the Generator Interconnection Process
ii. Interconnection Customer can proceed with the alternative mitigation plan that does not cause reliability violations

6.1.4. Backfilling

6.1.4.1 Eligibility

To be eligible as a backfill candidate, a project must be part of the DPP or the next DPP study group within sixty (60) Calendar days from the withdrawal date of a project creating such opportunity or before the completion of the restudy, whichever occurs first. The backfill candidate must meet all the Deposits (D1 and D2) and DPP Entry (M2) Milestone requirements pursuant to the requirements as delineated in the Attachment X of the tariff and Generator Interconnection Business Practices Manual prior to being considered as a backfill candidate. MISO will not consider any projects as backfill candidates that do not meet the above requirements.

i. In the event of a backfill opportunity, MISO will send a notice to all potential backfill candidates about such opportunity. Within ten (10) Business Days of receiving notification from MISO, the Interconnection Customer for the backfill candidate must provide MISO their decision on such qualification. If MISO does not receive written notification of acceptance within ten (10) Business Days, MISO will proceed with the restudy. Competing backfill candidates vying for the same backfill opportunity will be processed in accordance with Section 4.2 and Article 2.2.5 of Appendix 9 of the GIP. In the event that multiple candidates are identified from the same DPP study group, MISO will accept the first Interconnection Customer to provide such written acceptance.

ii. Once the restudy for the withdrawn project has begun, MISO will continuously monitor the Interconnection queue and if a backfill candidate is identified then MISO will send the affected Interconnection Customers a notice of the opportunity to backfill. The Interconnection Customer will have ten (10) Business Days to notify MISO of its acceptance of the backfill opportunity. MISO will stop all restudy work when a backfill candidate accepts the backfill opportunity. The Interconnection Customer will be required to fund all restudy costs[7] incurred up to the point when the backfill opportunity is accepted. Failure to fund all the restudy work after accepting a backfill position will result in the following:
   a. MISO will remove the backfill candidate from contention and recommence the restudy work after which the backfill window will be closed.
   b. The Interconnection Customer will still be required to fund the restudy costs pursuant to Section 3.6 of Attachment X.

iii. Backfill will not be permitted if the backfill candidate is deemed to materially impact the cost or schedule of other projects in the same DPP Group study from which the higher queued project withdrew

6.1.4.2 Criteria for evaluation of potential Backfill Candidates

MISO will use the following rule set when determining if a project will qualify as a backfill candidate for a withdrawn or terminated project, pursuant the backfilling process covered under Attachment X of the MISO tariff. The analysis to determine projects that may be considered for backfill will occur at the time a project in the DPP is deemed withdrawn (either voluntarily or involuntarily), and also prior to the completion of the restudy. Interconnection Customers can access the Interactive queue on the MISO website to view a list of withdrawn[8] projects.

To be considered a valid backfill candidate, a project must have the following attributes when compared to the withdrawn project:

i. Nearly the same electrical POI at the same kV level
ii. The same requested MW Amount
iii. The same Fuel Type
iv. Similar Machine Characteristics

[7] The Interconnection Customer can work with MISO to get a Good Faith cost estimate of the restudy work.
[8] https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx

In addition to the criteria mentioned above, MISO will use the following criteria related to the Interconnection Service of the backfill candidate:

i. A backfill candidate, with an NRIS request, will be allowed to replace a withdrawn project that had requested NRIS
ii. A backfill candidate, with an NRIS request, will be allowed to downgrade its NRIS to ERIS in order to replace a withdrawn project that had requested ERIS
iii. A backfill candidate, with and ERIS request, will be allowed to replace a withdrawn project that had requested ERIS.
iv. A backfill candidate, with an ERIS request, will be NOT be allowed to upgrade its ERIS to NRIS in order to replace a withdrawn project that had requested NRIS

6.1.5. Customer Funded Optional Study

Any existing Interconnection Customer can request an optional study, as pursuant to Section 10 of the Attachment X of the MISO Tariff. The purpose of these technical studies is to provide additional information to the Interconnection Customer that is normally outside the scope of a typical System Impact Study. MISO initially charges a sixty thousand dollar ($60,000) study deposit to perform such optional studies and then may request, if necessary, additional funds to complete the study.

6.1.5.1 Background

The Generation Interconnection System Impact Study results identify reliability constraints that must have a mitigation plan prior to the execution of a Generator Interconnection Agreement. Depending on the individual generator impact and the type of the requested interconnection service, there could be a situation where a reliability constraint is identified in the System Impact Study report but the Interconnection Customer is exempt from mitigating the constraint if its impact is below the threshold as identified in Section 6.1.1.1.6.

Therefore, despite not being responsible for paying for Network upgrades, identified in the System Impact Studies, an Interconnection Customer's generation facility can get curtailed in Real Time for the same constraint under varying operating environments. Therefore, to evaluate potential transmission upgrade options to reduce Real Time congestion and curtailment for their respective generating facilities, Interconnection Customers can request an Optional Interconnection Study by providing a detailed scope.

Since Optional Interconnection Studies are outside the scope of regular System Impact Studies and are performed out of regular interconnection study cycles, the results of any such analysis are non-binding.

6.1.5.2 Network Upgrade Funding and Facilities Studies:

If the Interconnection Customer(s) decide to fund the network upgrades, to mitigate the identified constraints identified in the Optional Interconnection Study, MISO will then facilitate the coordination with applicable Transmission Owners. With applicable agreements between Interconnection Customer and Transmission Owner(s) in place, MISO will include these network upgrades within its MISO Transmission Expansion Plan (MTEP) as "Other – MP Funded" project. MISO will work with applicable Transmission Owners to conduct a Facility Study. Facility Study timelines and cost would be consistent with Section 6.2 of this BPM.

6.1.5.3 MISO Sub-Regional Planning Meetings

Where Market Participant requests and funds a Facility Study, MISO staff will notify all stakeholders at its upcoming applicable Sub Regional Planning Meeting. Further, when necessary Facility Construction Agreements are in place, MISO staff will notify all stakeholders at subsequent SPM and include in MTEP as "Other - MP Funded" project.

6.1.5.4 Availability of ARRs

Interconnection customers can request MISO ARRs associated with funded transmission expansions. This will be handled by FTR group consistent with BPM-004.

6.1.5.5 Shared Network Upgrade Cost Allocation Treatment:

Pursuant to Section III(A)(2)(a) of Attachment FF, a Market Participant or a group of Market Participants are allowed assume cost responsibility to fund a network Upgrade on the Transmission System. However, any upgrade that is funded by the Interconnection Customer that was not identified as a required Network upgrade, during the Generation Interconnection Study process, will not qualify for the Shared Network Upgrade treatment as noted in Section 6.1.1.1.9.

6.1.6. External Network Resource Interconnection Service Study

This product gives Generating Facilities external to MISO the ability to procure NRIS under the MISO Tariff as long as it meets certain conditions.

To be eligible for study the Generating Facility must have a signed Interconnection Agreement with the interconnecting Transmission Provider or be in commercial operation at the time of the request. Additionally the Application Fee (D1), DPP Study Funding deposit (D2) and the DPP Entry (M2) Milestone deposit are required at the time of application for an external NRIS study request. Upon the receipt of a valid application, the request will be placed in the next applicable DPP cycle.

Deliverability studies will be processed in the same manner as any other Generating Facility requesting Network Resource Interconnection Service under MISO's tariff. MISO will perform all applicable ERIS reliability analysis as outlined in Section 6.1.1.1.2 to ensure system reliability for the injection from the Generating Facility external to MISO. In conjunction, a deliverability study will also be performed as outlined in Section 6.1.1.1.6.

The qualifying NRIS amounts will be memorialized through a MISO Service Agreement that will be filed at FERC. If any conditional service is granted, such service will be subjected to the annual interim studies outlined in Section 6.6. Generating Facilities requesting external NRIS must also procure firm Transmission Service to the MISO border through the host interconnecting Transmission Provider prior to the execution of a Service Agreement and such firm Transmission Service should be maintained for the duration of the Service Agreement.

6.2. Facility Study

The Facility Study will determine the cost and time estimate to construct the Network Upgrades and Transmission Owner's Interconnection Facilities necessary to physically and electrically interconnect the proposed Generating Facility to the Transmission System.

The Facilities Study will be broken down into two stages, the Interconnection Facility facilities study and Network Upgrade facilities study. The Interconnection Facility facilities study will be done in parallel with the DPP Phase II System Impact Study and the Network Upgrade facilities study will be done after the DPP Phase III System Impact Study is complete. The combination of the two facilities studies will determine the cost and construction schedule of identified Network Upgrades and Interconnection Facilities for each project in the Definitive Planning Phase.

6.2.1. Study Objectives

For facility improvements determined from the System Impact Study and based on the official Point of Interconnection:

i. Design and specification of facility improvements in accordance with Good Utility Practice and applicable planning and design criteria. These criteria must be consistently applied to all existing and proposed generation projects in a Local Balancing Authority.
ii. Development of detailed cost estimates that include equipment, engineering, procurement and construction costs according to the level of accuracy possible based on the proposed in-service date of the projects.
iii. Identification of the electrical switching configuration of the connection equipment, including, but not limited to the transformer, switchgear, meters, and other station equipment.
iv. Identification of the nature and estimated cost of any Transmission Owner's Interconnection Facilities and Network Upgrades, System Protection Facilities and Distribution Upgrades on the Transmission System and Affected Systems necessary to accomplish the interconnection.
v. An estimate of the time required to construct facilities and required phasing of improvements, if any.
vi. Preparation of the draft Appendices to the Interconnection Agreement/Facilities Construction Agreement with completed exhibits

Generally, the Transmission Owners with facilities needing upgrades identified in the System Impact study will determine the construction and cost estimate of those upgrades and/or Interconnection Facilities. Cost estimates will be determined to a +/- twenty percent (20%) margin if the lead time to the in-service date for the required facilities does not exceed eighteen (18) months. For studies requiring cost estimates for longer lead items, a good faith estimate will be developed. To the extent the Interconnection Customer requests a cost estimate with a smaller margin of error, and the Transmission Owner can reasonably obtain that estimate without holding up other projects in the Definitive Planning Phase, then the estimate will be within the negotiated margin.

6.2.2. Scope of Upgrades

Facilities Study will clearly describe and list various upgrades required to interconnect the proposed Generating Facility. The report should include the following Exhibits to include in Appendix A of the Generator Interconnection Agreement:

i. Exhibit A1: (Interconnection Customer provides to Consultant) Interconnection Customer Generating Facility and Interconnection Customer constructed Interconnection Facilities. This would include Interconnection Customer Single Line or Elementary One-line Diagram(s) and system Maps depicting and identifying the Point of Interconnection, meter point(s), metering and relaying CT arrangements, the Ownership demarcation(s).
ii. Exhibit A2: (Consultant develops) Transmission Owner single line or Elementary One-line Diagram(s) and system Maps depicting and identifying the Point of Interconnection, meter point(s), metering and relaying CT arrangements relative to the Interconnection, the Ownership demarcation(s), the Transmission Owner Interconnection Facilities, Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades and Affected System Upgrades.
iii. Exhibit A3: (Consultant develops) a Site Plan and/or General Arrangement drawing showing the entire interconnection substation complete with all transmission line structures impacted by the new substation. This drawing will be based on and developed from the Interconnection Customer provided certified site survey drawing.
iv. Exhibit A4: (Consultant develops) a basic Plan and Profile drawing showing the required line tap work associated with the interconnection sub or switching station. This drawing will be based on and develop from the Interconnection Customer provided certified site survey drawing.
v. Exhibit A5: (Consultant develops) a categorized list or tabulation of Transmission Owner Interconnection Facilities, non-Stand-Alone Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades and Affected System Upgrades to be constructed by the Transmission Owner.
vi. Exhibit A6: (Consultant develops) a categorized detailed cost breakdown of facilities identified in Exhibit A5 as by Transmission Owner, by major component (e.g. transformer, line terminal, breaker, etc.) and by subcomponent (e.g. lightning arrester, disconnect switches, protection equipment, communication equipment, monitoring and alarm equipment, metering facilities, grounding, special controls or equipment needed to meet stability or short circuit criteria, etc.) Similarly, each

transmission line should be subcategorized by ROW acquisition needs (new/existing and major/minor) and the major and minor components.

6.2.3. Cost of Upgrades

The Facilities Study will provide a breakdown of various components of Network Upgrades and Interconnection Facilities required to interconnect the proposed Generating Facility. The report should include the following Exhibits to include in Appendix A of the Generator Interconnection Agreement:

i. Exhibit A7: (Consultant develops) a categorized tabulation of Transmission Owner Interconnection Facilities, Non-Stand-Alone Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades to be constructed by the Interconnection Customer.
ii. Exhibit A8: (Consultant develops) a categorized detailed cost breakdown of facilities identified in Exhibit A7 as by the Interconnection Customer by major component (e.g. line terminal, etc.) and by subcomponent (e.g. breaker, lightning arrester, disconnect switches, protection equipment etc.).
iii. Exhibit A9: (Consultant develops) Total categorized cost estimate for Transmission Owner Interconnection Facilities and Network Upgrades (Stand-Alone and non-Stand-Alone) including a list or tabulation of Interconnection Network Upgrades (Stand-Alone and non-Stand Alone) that are subject to the Attachment FF treatment. No refund for radial facilities from network to the Generating Facility.

6.2.4. Conditions to GIA (Appendix A10)

The Facilities Study report identifies the cost and schedule of Network Upgrades that are identified for Interconnection projects. In addition to these upgrades, MISO may identify other conditions which may include other higher or similarly queued Interconnection Requests, other MTEP assumptions embedded in the study case, Distribution Upgrades, or System Protection Upgrades for higher or similarly queued projects.

i. Exhibit A10: MISO will perform analysis on the GI study case and monitor upcoming MTEP upgrades that are not yet in service based on the following Criteria:
   a. DF ≥ 5% AND
   b. MW Impact ≥ 5 MW, AND
   c. MW Impact ≥ 1% of the Facility Rating

All Network Upgrades identified in the System Impact Study, required to mitigate Voltage and Stability related issues, will be included in the Appendix 10 to the GIA.

Upcoming MTEP projects applicable to study GI project(s), proposed for voltage & stability purpose, will be listed.

6.2.5. Facility Study Exhibits for the GIA

The Facilities Study report will include the following exhibits to describe the Milestones, Construction and Coordination Schedule for the proposed interconnection. These exhibits will be included in the Appendix B of the Generator Interconnection Agreement:

i. Exhibit A11 (Interconnection Customer provides): A list of key project and regulatory activities that must be met by the Interconnection Customer after receipt of the final GIA for the project to maintain its queue position or mutually agreeable in-service schedule. The Interconnection Customer must either provide evidence of continued Site Control, unless the Interconnection Customer is exempt from this requirement pursuant to Section 5.1.2 of the GIP, in which case the Interconnection Customer may instead elect to post two hundred fifty thousand dollars ($250,000), which will be applied towards future construction costs, within fifteen (15) Business Days of the final GIA. The Interconnection Customer must also provide evidence that one or more of the following items are in development within one hundred eighty (180) Calendar Days of receiving the final GIA: 1) contract for the supply or transportation of fuel to the Generating Facility; 2) contract for the supply of cooling water to the Generating Facility; 3) contract for engineering services, construction services, or generating equipment; 4) contract for the sale of electric energy or capacity from the Generating Facility; or 5) application for state and local air, water, land or federal nuclear permits and that the application is proceeding per regulations.

ii. Exhibit A12 (Consultant develops): Construction and Coordination Schedule of the Generating Facility, Interconnection Customer Interconnection Facilities, the Transmission Owner Interconnection Facilities, Network Upgrades (subcategorized by non-Stand-Alone and Stand-Alone Network Upgrades) identifying long lead items, outage issues and expected critical path coordination items. Identify activity start dates, duration of activity and expected completion dates for all major components. Identify Progress Payments Identify start-up and test responsibilities. Identify Transmission Owner permitting process and issues including right-of-way acquisition for new transmission lines or substations.

iii. Exhibit A13 – (Consultant Develops) List of affected Transmission Owner activities and schedules necessary to obtain regulatory approval for facilities to be provided by affected Transmission Owner(s).

6.2.6. Interconnection and Operating Guidelines

The study report should include any "project specific" guidelines or requirements for the interconnection and/or operation of the Facility that go beyond the generic and universal requirement of "Good Utility Practice." These requirements/guidelines may include topics such as System Protection Facilities, communication requirements, metering requirement, grounding requirements, transmission line and substation connection configurations, unit stability requirements, equipment ratings, short circuit requirements, synchronizing requirements, generation and operation control requirements, data provisions, energization inspection and testing requirements (if applicable), the unique requirements (if any), of the transmission owner to which the facility will be physically interconnected, switching and tagging, data reporting requirements, training, capacity determination and verification (including Ancillary Services and certification), emergency operations, including system restoration and black start arrangements, identified must-run conditions, provision of Ancillary Services, specific transmission requirements of nuclear units to abide by all NRC requirements and regulations, stability requirements, including generation short circuit ratio considerations, limitations of operations in support of emergency response, maintenance and testing, and any other specific requirement not listed above.

All such Interconnection and Operating Guidelines must be included in Appendix C to the Generator Interconnection Agreement (GIA).

6.2.6.1 Interconnection Agreement Appendices Populated

The Facilities Study report must include the Exhibits A1 through A13 of the GIA populated in draft format. These exhibits must go through legal review by the Transmission Owner prior to publishing the report. Having these draft GIA exhibits in the Facilities Study report will provide a good starting point for the development of the Generator Interconnection Agreement and will make the GIA review process smoother and less time consuming.

6.2.7. Submittal of IA for Appendix Review

MISO will circulate a draft GIA/FCA to the parties involved within fifteen (15) Calendar Days after receipt of comments on the Facilities Study and draft GIA Appendices. At the same time, MISO will schedule a series of conference calls to review and finalize the Appendices to the GIA. The meetings will take place in the following order:

i. Technical Review Meeting: The purpose of this meeting will be to address any technical issues on the Appendices to the GIA/FCA. MISO will provide these documents for review at least five (5) Business days prior to the date comments are due. The participants are expected to review the technical information in the draft appendices to the GIA/FCA and provide any comments to the MISO at least two (2) Business Days prior to the meeting.
ii. Legal Review Meeting: Will address any legal issues in the draft GIA/FCA. The participants are expected to complete a legal review of the draft GIA/FCA and provide any comments to the MISO at least two (2) Business Days prior to the meeting. Typically the Wrap-Up portion of the meeting will cover any remaining open issues including any open technical issues.

Five (5) Business Days after the start of negotiations, the Interconnection Customer shall provide:

i. Its initial payment option pursuant to Article 11.5 of the GIA, and
ii. Interconnection Customer's desired ISD and COD, if different from the dates in the Facility Study Report.

These dates will be used to complete the cash flow payments and Milestones in Appendix B of the GIA.

6.2.8. Submittal of GIA/FCA for Execution / Filing Unexecuted

Within fifteen (15) Business Days of the Legal Review Meeting, MISO will circulate the final Generation Interconnection Agreement and Facility Construction Agreement (if applicable) to all parties for execution. If there is a deviation in pro-forma Agreement, the GIA/FCA will be filed with the FERC after execution by all parties. Otherwise the MISO will maintain the executed agreement and notify to FERC via its next Electric Quarterly Report (EQR). If the GIA negotiations result in an impasse, the MISO will file the Agreement unexecuted with the FERC no later than ten (10) Business Days from the date of party(ies) declaring an impasse.

6.2.9. Provisional Generator Interconnection Agreement

Interconnection Customer can request a provisional Generator Interconnection Agreement for a project for a limited operation of the plant at any time through Decision Point II, or if the schedule becomes delayed by more than sixty (60) Calendar Days between Decision Point II and the end of the Facilities Studies. An Interconnection Customer must meet all of the following conditions before a Provisional Generator Interconnection Agreement will be offered:

i. All planning studies identifying system impacts and mitigations have been completed in accordance with the NERC and applicable regional reliability criteria through a Provisional Interconnection Study
ii. Project has met all Milestones in the process (i.e. D1, D2, M1, M2, M3, and M4; M3 and M4 will be four thousand dollars ($4,000) per MW of the Interconnection Request if not already calculated)
iii. Facility Study has been completed for the required Interconnection Facilities for the project or there are existing Interconnection Facilities that can be used for the project without any modifications
iv. Interconnection Customer agrees to install equipment or protective devices that would disconnect the Generating Facility in the event the output of the Generating Facility exceeds the operational limit described in the provisional Generation Interconnection Agreement
v. Interconnection Customer agrees to assume all risks and liability associated with the changes in the Interconnection Agreement including but not limited to the change in output limit and additional costs for Network Upgrades

Under the provisional Generator Interconnection Agreement, maximum permissible output of the Generating Facility will be determined based on the incremental transfer capability available at the Point of Interconnection to the MISO footprint. Such limit will be identified on the Base Cases used for Available Flowgate Capacity (AFC) calculations under Attachment C of the MISO OATT. Analysis to identify the operational limit for provisional GIA will be performed after Interconnection Customer meets all process Milestones for the project. The operational limit for the Generating Facility under provisional GIA will be reviewed and updated as required on a planning year quarterly basis.

6.2.9.1 Provisional Interconnection Agreement Limit Methodology

The MISO methodology for calculating operating limits for all generators requesting interconnection service by executing a Provisional Interconnection Agreement (PIA). The methodology uses a two-pronged approach as follows:

i. A MUST DC transfer analysis will calculate Distribution Factors of all generators that have greater than 20% (OTDF) and a 5% (PTDF) impacts on all constraints.

ii. These Distribution Factors will be used to calculate the operating limits, in addition to other constraints as demonstrated in the examples that follow, by utilizing Microsoft Excel Solver optimization tool.

In order to implement this methodology, there are several inputs and assumptions that have to be addressed that have been outlined below.

6.2.9.1.1 PSSE Base Case Assumptions

i. MISO will use a seasonal case that will be downloaded from Model on Demand (MOD) and adjusted to match the study horizon. The adjustments will be strictly limited to the dispatch of all NR units with a signed GIA, with like fuel types of the generator with a PIA, and a planned in-service date prior to the operating horizon. The NR units will be dispatched at 100% and the increase in the generation will be offset by turning off Gas Combustion Turbines and Diesel Units.
ii. No changes will be made to the load pattern in the case.
iii. No changes will be made to any other generator dispatch.
iv. No changes will be made to the case topology.

6.2.9.1.2 Input Files and Analysis Assumptions

i. MISO will use N-1 Contingencies to evaluate the Distribution Factors for each unit on all constraints.
ii. MISO will use monitored file for all facilities above 34 kV.
iii. MISO will use the most current available generator information and use the Pmax and Pmin based on the generator capability curve.

6.2.9.1.3 Generator Output Optimization Equations

The main concept behind this technique is to optimize the summation of Initial Flow of each constraint and the individual MW impact of each PIA generator on that constraint, such that the optimized flow on the monitored element is less than or equal to the Emergency rating of the line under the key contingencies being studied. Also, while optimizing the flow on constrained facilities, the generator limits are used as constraints such that the generation output is maximized for each optimized constrained flow. In other words, the desired solution would try to maximize the output of each unit such that the flow on the constrained element will be equal to or less than the rating of the monitored element.

EQUATION SETUP WITH CONSTANTS AND VARIABLES

Y1 = Unit 1
Y2 = Unit 2
C1 = Total flow on Monitored element of Constraint 1
C2 = Total flow on Monitored element of Constraint 2
C3 = Total flow on Monitored element of Constraint 3
C4 = Total flow on Monitored element of Constraint 4
Cn = Total flow on Monitored element of Constraint n
Ygen1 = Output of Unit 1
Ygen2 = Output of Unit 2
Ymax1 = Maximum Output of Unit 1
Ymax2 = Maximum Output of Unit 2
Ymin1 = Minimum Output of Unit 1 (Set to Zero for analysis)
Ymin2 = Minimum Output of Unit 2 (Set to Zero for analysis)
α 1 = Initial MW Flow on Monitored Element of Constraint 1
α 2 = Initial MW Flow on Monitored Element of Constraint 2
α 3 = Initial MW Flow on Monitored Element of Constraint 3
α 4 = Initial MW Flow on Monitored Element of Constraint 4
α n = Initial MW Flow on Monitored Element of Constraint n
β 1,1 = DF of Unit 1 on constraint 1
β 1,2 = DF of Unit 1 on constraint 2
β 1,n = DF of Unit 1 on constraint n
β 2,1 = DF of Unit 2 on constraint 1
β 2,2 = DF of Unit 2 on constraint 2
β 2,n = DF of Unit 2 on constraint n
β k,1 = DF of Unit k on constraint 1
β k,n = DF of Unit k on constraint n

If we try to calculate the total constraint flow on Monitored Element of Constraint **C1** with two units **Y1** and **Y2**, then the equation is as follows:

$$C1 = \alpha 1 + Ygen1 * \beta 1,1 + Ygen2 * \beta 2,1 + Ygenk * \beta k,1$$

If instead of using two units **(Y1 and Y2)**, we used **k** units (all the units with provisional and conditional GIAs) then the above equation would change to the following equation and capture the Distribution Factors of all units **(Y1 to Yk)** on Constraint **C1** as follows:

$$C1 = \alpha 1 + Ygen1 * \beta 1,1 + Ygen2 * \beta 2,1 \ldots\ldots. + Ygenk * \beta k,1$$

Similarly, we can extend the same concept for all constraints as follows:

$$C2 = \alpha 2 + Ygen1 * \beta 1,2 + Ygen2 * \beta 2,2 \ldots\ldots. + Ygenk * \beta k,2$$
$$C3 = \alpha 3 + Ygen1 * \beta 1,3 + Ygen2 * \beta 2,3 \ldots\ldots. + Ygenk * \beta k,3$$
$$C4 = \alpha 4 + Ygen1 * \beta 1,4 + Ygen2 * \beta 2,4 \ldots\ldots. + Ygenk * \beta k,4$$

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$$Cn = \alpha n + Ygen1 * \beta 1,n + Ygen2 * \beta 2,n \ldots\ldots. + Ygenk * \beta k,n$$

6.2.9.1.4 Optimization Technique using EXCEL SOLVER

The optimization process needs two sets of critical data:

a. The Distribution Factors for each unit for all constraints that are obtained from the results of a MUST First Contingency Incremental Transfer Capability DC transfer analysis. Therefore, the MUST output will provide **β 1,1, β 2,1** etc. values.
b. The Pmax and Pmin for each generator that has signed a provisional or conditional GIA. From equations above, we will need **Ymax1, Ymin1** etc.

Once the data from 6.2.9.1.4.a and 6.2.9.1.4.b is obtained, then the Excel Solver tool will be used to calculate the operating limits with the following set of constraints:

Maximize the output of all Units **Y1- Yn** such that the constrained flows for **C1** to **Cn** are optimized to the rating of the line. In other words, The Excel Solver will solve and come up with the optimized value for all Unit outputs within the following constraints:

Maximize **Σ Ygen (1 to k)** within the following constrained parameter values:

Ymax1>=Ygen1>Ymin1
Ymax2>=Ygen2>Ymin2
Ymaxk>=Ygenk>Ymink
AND

Optimize **C1** = Rating of the monitored element of **C1**
Optimize **C2** = Rating of the monitored element of **C2**
Optimize **Cn** = Rating of the monitored element of **Cn**

6.2.9.1.5 Frequency of these studies

MISO will perform this analysis every planning year quarter and post the results on MISO OASIS under the following link:

http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_report_Page_for_TIAs.mht

6.2.9.2 Microsoft Excel Help Files Solver Description

Further description of the Excel Solver function can be found at the following link:

https://support.office.com/en-au/article/An-introduction-to-optimization-with-the-Excel-Solver-tool-1f178a70-8e8d-41c8-8a16-44a97ce99f60

6.2.10. Use of Multi Party Facility Construction Agreement (MPFCA)

A Multi-Party Facility Construction Agreement will be developed in the event multiple Interconnection Requests share the responsibility for a common Network Upgrade or System Protection Facility on the Transmission Owner's Transmission System ("Common Use Upgrade" or "CUU"). A separate MPFCA will be developed for a CUU on each Transmission Owners' Transmission System. A CUU may consist of multiple Network Upgrades and/or System Protection Facilities.

The Network Upgrades and System Protection Facilities required solely for a single Interconnection Request on the direct-connect Transmission Owner's Transmission System will continue to be included in the GIA for that Interconnection Request. Further, any Network Upgrades or System Protection Facilities that are not a CUU on the Transmission System of a Transmission Owner which is not a party to the GIA will continue to be included in the Facility Construction Agreement (FCA).

The Interconnection Customer's GIA will include in Appendix A and Appendix B the facilities that are required under separate FCA(s) and/or MPFCA(s) and corresponding Milestones that must be completed prior to commencement of service under the GIA.

Reasonable efforts will be made to conduct negotiations and prepare appendices for a GIA in parallel with any related FCA(s) and MPFCA(s). If parallel processing is impractical, MISO may vary the order in which it prepares the necessary documents and conducts negotiations. In general, for a particular project, MISO will prioritize the GIA negotiations ahead of the FCA negotiations, then the FCA negotiations ahead of the MPFCA negotiations.

Interconnection Customers with Interconnection Requests that require a CUU will be held responsible to execute and provide irrevocable security for their respective shares of a MPFCA (or in the case of an unexecuted MPFCA, provide irrevocable security after acceptance of the unexecuted MPFCA by FERC) in the event that:

i. A constraint is identified in the Definitive Planning Phase System Impact Study, that meets the criteria to require mitigation, and
ii. One or more of the following:
    a. More than one Interconnection Request contributes to that constraint, and/or
    b. Other Interconnection Request(s) contribute to a different constraint(s) requiring mitigation before commencement of their Interconnection Service, and where:
        i. The constraint(s) is resolved by the same upgrade (i.e., CUU); and
        ii. The CUU is determined to be the most prudent upgrade to resolve the constraint(s) to such a level that the CUU enables the interconnection of multiple Interconnection Requests.

6.2.11. Refunds of Definitive Planning Phase Milestones (M2, M3, M4)

Interconnection Customers are eligible to receive one hundred percent (100%) refund of the Definitive Planning Phase Entry Milestone (M2) only when the Interconnection Request is withdrawn or deemed withdrawn prior to the end of Interconnection Customer Decision Point I. If the Interconnection Request is withdrawn any time after the Interconnection Customer Decision Point I, then the Definitive Planning Phase Entry Milestone (M2) becomes at risk and will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

Interconnection Customers are eligible to receive one hundred percent (100%) refund of the Definitive Planning Phase II Milestone (M3) only when the Interconnection Request is withdrawn or deemed withdrawn before the end of Interconnection Customer Decision Point II. If the Interconnection Request is withdrawn any time after the Interconnection Customer Decision Point II, then the Definitive Planning Phase II Milestone (M3) becomes at risk and will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

Interconnection Customers are not eligible to receive any portion of the Definitive Planning Phase II Milestone (M4) if the Interconnection Customer decides to withdraw its Interconnection Request any time after entering the Definitive Planning Phase III. The Definitive Planning Phase II Milestone (M4) will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

Milestone payments will be refunded in the event the Interconnection Customer withdraws because the total Network Upgrade cost estimates in the DPP Phase III System Impact Study increased by more than twenty-five percent (25%) and more than ten thousand dollars ($10,000) per MW over the DPP Phase II System Impact Study as a result of MISO, Affected System or Transmission Owner error.

Milestone payments will also be refunded in the event the Interconnection Customer withdraws and the total Network Upgrade cost estimates in the Facilities Study increased by more than twenty-five percent (25%) and more than ten thousand dollars ($10,000) per MW over the Network Upgrade cost estimates in the DPP Phase III Interconnection System Impact Study.

Milestone payments will also be refunded in the event the Interconnection Customer withdraws within the later of five (5) Business Days or at the end of a Decision Point, if applicable, of results indicating designated increases in estimated upgrade costs across the following intervals:

1. DPP Phase I to DPP Phase II
    a. An increase in MISO Network Upgrade costs of twenty-five percent (25%) and more than ten thousand dollars ($10,000) per MW from the preliminary SIS to the Revised SIS; or
    b. An increase in Affected System upgrade costs on transmission systems other than the MISO Transmission System of thirty percent (30%) and more than ten thousand dollars ($10,000) per MW.
2. DPP Phase II to DPP Phase III
    a. An increase in MISO Network Upgrade costs of thirty-five percent (35%) and more than fifteen thousand dollars ($15,000) per MW from the Revised SIS to any DPP Phase II SIS; or
    b. An increase in Affected System upgrade costs on transmission systems other than the MISO Transmission System of forty percent (40%) and more than fifteen thousand dollars ($15,000) per MW.
3. DPP Phase I to DPP Phase III
    a. An increase in MISO Network Upgrade costs of fifty percent (50%) and more than twenty thousand dollars ($20,000) per MW from the Preliminary SIS to any DPP Phase III SIS; or
    b. An increase in Affected System upgrade costs on transmission systems other than the MISO Transmission System of fifty-five percent (55%) and more than twenty thousand dollars ($20,000) per MW.

6.3. Coordination of studies between PJM and MISO

In accordance with Section 9.3.3 of the MISO-PJM Joint Operating Agreement ("JOA"), MISO and PJM shall conduct Interconnection Studies, as necessary, to determine the impacts of Interconnection Requests on each other's transmission system, which will be treated as an Affected System. This joint coordination of Interconnection Studies will be in addition to the existing Interconnection Studies that MISO and PJM already perform to evaluate the impacts of their respective queues on their own transmission system, and will be subject to the guidelines laid out in the MISO-PJM JOA.

The Transmission reinforcement and the study criteria used in the Coordinated Interconnection Studies will honor and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and their respective Tariffs.

When MISO and PJM perform any Coordinated Interconnection Study, the PJM and PJM Transmission Owner study and reinforcement criteria will apply to PJM transmission facilities and the MISO and MISO Transmission Owner study and reinforcement criteria will apply to MISO transmission facilities.

Coordination timing, as prescribed below, shall be based on the current MISO and PJM study cycles and will be adjusted if there are changes to the study cycle timelines in the future.

6.3.1. Study of PJM Interconnection Request Impacts on MISO Transmission

During the course of PJM Interconnection studies, PJM shall monitor the MISO transmission system and provide the draft results of the potential impacts to MISO. These potential impacts shall be included in the PJM System Impact Study report along with any information regarding the validity of these impacts and possible mitigation received from MISO and the MISO Transmission Owners.

Following the completion of the PJM Feasibility Study and the execution of the PJM System Impact Study Agreement by the customer, 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 requests on the MISO transmission system.

MISO and the MISO Transmission Owners shall study the impact of the PJM Interconnection on the MISO transmission system and provide draft results to PJM by:

- March 1 for PJM interconnection requests provided to MISO on or before October 15 of the previous year,
- September 1 for PJM interconnection requests provided to MISO on or before April 15 of the same year.

These impacts will be studied using methodology and criteria specified in Section 6.1 of the MISO BPM and may include thermal analysis and other analysis as necessary. These impacts identified by MISO shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcement(s). At times PJM may identify to MISO the need to perform studies associated with an Interconnection request other than the times identified above. MISO shall endeavor to study these requests at the earliest time that is feasible, but not later than the times as specified above (commencing after April 15 and October 15).

In the event of project withdrawals in the PJM queue, MISO may perform additional reliability analysis during the PJM Facilities Study phase and revise the affected system study results that were provided during the PJM System Impact Study phase.

If MISO identifies required Network Upgrades on the MISO transmission system, due to a PJM Interconnection request, the PJM Interconnection Customer(s) shall be required to follow all provisions, delineated under Attachment X of the MISO tariff, related to Facilities Study funding and appropriate Network Upgrade Facility Construction Agreement.

Cost allocation for required Network Upgrades on the MISO transmission system, for PJM Interconnection projects, shall be governed by and subject to MISO Tariff and Manuals. MISO will validate all constraints identified by PJM on MISO's transmission system before assigning costs that shall be determined in accordance with Section 6.1.5.2 of this BPM.

6.3.2. Study of MISO Interconnection Request Impacts on PJM Transmission

During the course of MISO Interconnection studies, MISO shall monitor the PJM transmission system and provide the draft results of potential impacts to PJM. These 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.

Prior to commencing the MISO DPP study MISO shall forward to PJM, at a minimum of twice per year (January 1 and July 1), MISO Interconnection Requests and information necessary for PJM and the PJM Transmission Owners to study the impact of the requests 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 requests and provide draft results on the PJM transmission system by:

- March 31, for requests submitted to PJM on or before January 7th of the same year, and

- September 29 for requests submitted to PJM on or before July 8 of the same year.

These impacts identified by PJM shall include a description of the required reinforcements on PJM's transmission system, an estimated planning level cost and construction schedule estimates of the system reinforcement. At times MISO may identify to PJM the need to perform studies associated with an Interconnection other than the times identified above. PJM shall endeavor to study these requests at the earliest time that is feasible, but not later than the times as specified above (commencing after January 7 and July 7).

If PJM identifies required Network Upgrades on the PJM transmission system, due to a MISO Interconnection request, then the MISO Interconnection Customer(s) shall be required to follow all provisions delineated under the PJM Tariff related to Facilities Study funding and appropriate Network Upgrade Facility Construction Agreement obligations.

Cost allocation for Network Upgrades necessary on the PJM transmission system due to MISO Interconnection projects shall be governed by and subject to the PJM Tariff and related Manuals.

6.3.3. Coordination of Projects with Provisional/Conditional GIAs

If a generation interconnection project is conditional upon Network Upgrades on the Affected System, and comes in service prior to those Network Upgrades being completed, that project's output will be subject to limitations in accordance with the applicable tariff of the Affected System.

6.4. Coordination of Studies between SPP and MISO

In accordance with Section 9.4 of the MISO-SPP Joint Operating Agreement ("JOA"), MISO and SPP shall conduct Interconnection Studies, as necessary, to determine the impacts of Interconnection Requests on each other's transmission system which will be treated as an affected system. This joint coordination of Interconnection Studies will be in addition to the existing Interconnection Studies that SPP and MISO already perform to evaluate the impacts of their respective queues on their own transmission system, and will be subject to the guidelines laid out in the MISO-SPP JOA.

The transmission reinforcement and the study criteria used in the coordinated interconnection studies will honor and incorporate provisions as outlined in the SPP and MISO Business Practices Manuals, study procedures, and their respective Tariffs.

When MISO and SPP perform any coordinated interconnection study, the SPP and SPP Transmission Owner study and reinforcement criteria will apply to SPP transmission facilities and the MISO and MISO Transmission Owner study and reinforcement criteria will apply to MISO transmission facilities. When MISO performs a study on a SPP Interconnection request, that request's output will be dispatched into the SPP footprint. When SPP performs a study on a MISO Interconnection request, that request's output will be dispatched into the MISO footprint.

Coordination timing, as prescribed below, shall be based on the current MISO and SPP study cycles and will be adjusted if there are changes to the study cycle timelines in the future.

6.4.1. Study of SPP Interconnection Request Impacts on MISO Transmission

During the course of SPP Interconnection studies, SPP shall monitor the MISO transmission system and provide the draft results of the potential impacts to MISO. These potential impacts shall be included in the SPP Definitive Interconnection System Impact Study (DISIS) report along with any information regarding the validity of these impacts and possible mitigation received from MISO and the MISO Transmission Owners.

Following the completion of the SPP System Impact Study (DISIS), SPP shall forward to MISO, at a minimum of twice per year (August 1 and March 1), information necessary for MISO and the MISO transmission owners to study the impact of the SPP Interconnection requests on the MISO transmission system.

MISO and the MISO Transmission Owners shall study the impact of the SPP Interconnection on the MISO transmission system and provide draft results to SPP by:

- November 15 for SPP interconnection requests provided to MISO on or before August 1 of the same year,
- June 15 for SPP interconnection requests provided to MISO on or before March 1 of the same year.

These impacts will be studied using methodology and criteria specified in Section 6.1 of this BPM and may include thermal analysis and other analysis as necessary. These impacts identified by MISO shall include a description of the required system reinforcements, an estimated planning level cost and construction schedule estimates of the system reinforcement. At times SPP may identify to MISO the need to perform studies associated with an Interconnection Request other than at the times identified above. MISO shall endeavor to study these requests at the earliest time that is feasible, but not later than the times as specified above (commencing after March 1 and August 1).

If MISO identifies required Network Upgrades on the MISO transmission system, due to an SPP Interconnection request, the SPP Interconnection Customer(s) shall be required to follow all provisions, delineated under Attachment X of the MISO tariff, related to Facilities Study funding in accordance with Section 6.2 of this BPM and the appropriate Network Upgrade Facility Construction Agreement. The SPP Interconnection Customer will be required to fund this Facility Study.

Cost allocation for required Network Upgrades on the MISO transmission system, for SPP Interconnection projects, shall be governed by and subject to MISO Tariff and Manuals. MISO will validate all constraints identified by SPP on MISO's transmission system before assigning costs that shall be determined in accordance with Section 6.1.5.2 of this BPM.

6.4.2. Study of MISO Interconnection Request Impacts on SPP Transmission

During the course of MISO Interconnection studies, MISO shall monitor the SPP transmission system and provide the draft results of potential impacts to SPP. These 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 SPP and the SPP Transmission Owners.

Prior to commencing the MISO DPP study MISO shall forward to SPP, at a minimum of twice per year (March 1 and September 1), MISO Interconnection Requests and information necessary for SPP and the SPP Transmission Owners to study the impact of the requests on the SPP transmission system. For the prescribed times when MISO provides this information to SPP, March 1 and September 1, SPP and the SPP Transmission Owners shall study the impact of the MISO interconnection requests and provide draft results on the SPP transmission system by:

- December 15, for requests submitted to SPP on or before September 1 of the same year, and

- June 15, for requests submitted to SPP on or before March 1 of the same year

These impacts identified by SPP shall include a description of the required reinforcements on SPP's transmission system, an estimated planning level cost. At times MISO may identify to SPP the need to perform studies associated with an Interconnection Request other than at the times identified above. SPP shall study these requests no later than the times as specified above (commencing after March 1 and September 1).

If SPP identifies required Network Upgrades on the SPP transmission system, due to a MISO Interconnection request, then the MISO Interconnection Customer(s) shall be required to enter into an Interconnection Facilities Study Agreement for Affected System Generators. The MISO Interconnection Customer will be required to fund this study. Following the completion of the Interconnection Facilities Study, the MISO Interconnection Customer(s) may be required to enter into an Affected Systems' Facilities Construction Agreement with the Affected SPP Transmission Owner and SPP. Funding by the MISO Interconnection Customer for the Interconnection Studies and Network Upgrades shall be consistent with funding practices by SPP Interconnection Customers under Attachment V of the SPP OATT for Interconnection Studies and Network Upgrades. Cost allocation for Network Upgrades necessary on the SPP transmission system due to MISO Interconnection Requests shall be consistent SPP Interconnection Customer cost allocation for Network Upgrades subject to the SPP Tariff and related Manuals.

6.4.3. Coordination of Projects with Provisional/Conditional GIAs

If a generation interconnection project is conditional upon Network Upgrades on the Affected System, and comes in service prior to those Network Upgrades being completed, that project's output will be subject to limitations in accordance with that respective RTO's tariff.

6.4.3.1 Limitations on SPP Generators with Impacts on the MISO System

SPP Generation Interconnection Projects that come into service prior to completion of required Network Upgrades on the MISO transmission system will be subject to the MISO Quarterly Operating Limit process, as outlined in the MISO Tariff in Attachment X Section 11.5 and in the MISO Transmission Access Planning Provisional Interconnection Agreement Limit Methodology whitepaper, until required Network Upgrades on the MISO transmission have been completed. MISO will coordinate project output limitations with SPP on a quarterly basis, and MISO will provide SPP the list of conditions that will be added to SPP Interconnection Customer's Interconnection Service agreement.

6.4.3.2 Limitations on MISO Generators with Impacts on the SPP System

MISO Generation Interconnection projects that come into service prior to completion of required Network Upgrades on the SPP transmission system will be subject to SPP's study process for Limited Operation. SPP updates the output limits on all Generator Interconnection Agreements when events occur on the Transmission System that are listed in the Limited Operation Impact Study for that generator to account for changing transmission and generation assumptions. SPP will coordinate project output limitations with MISO on a quarterly basis or more often as events occur, and SPP will provide MISO the list of conditions that will be added to MISO Generator Interconnection Agreement.

6.4.3.3 Limitations on PJM Generators with Impacts on the MISO System

PJM Generation Interconnection Projects that come into service prior to completion of required Network Upgrades on the MISO transmission system will be subject to the MISO Quarterly Operating Limit process, as outlined in the MISO Tariff in Attachment X Section 11.5 and in the MISO Transmission Access Planning Provisional Interconnection Agreement Limit Methodology whitepaper, until required Network Upgrades on the MISO transmission system have been completed. MISO will coordinate project output limitations with PJM on a quarterly basis, and MISO will provide PJM the list of conditions that will be added to PJM Interconnection Customer's Interconnection Service agreement.

6.4.3.4 Limitations on MISO Generators with Impacts on the PJM System

MISO Generation Interconnection projects that come into service prior to completion of required Network Upgrades on the PJM transmission system will be subject to PJM's yearly process until required Network Upgrades on the PJM transmission system have been completed. PJM updates the output limits on all Interconnection Service agreements on a yearly basis, at a minimum, to account for changing transmission and generation assumptions. Any significant changes to the assumptions of the study may be reviewed on a more frequent basis. PJM will coordinate project output limitations with MISO on a yearly basis, and PJM will provide MISO the list of conditions that will be added to MISO Generator Interconnection Agreement.

6.5. Coordination of Studies between Manitoba Hydro (MH), Minnkota Power Cooperative (MPC), and MISO

6.5.1. Application of Governing Agreements

6.5.1.1 Governing Agreement for MPC and MISO Coordination

This coordination procedure is established between MPC and MISO pursuant to sections 9.1 and 14.1 of the MISO-MPC Coordination Agreement.

6.5.1.2 Governing Agreement for MH and MISO Coordination

This coordination procedure is established between MH and MISO pursuant to section 5.4 of the MISO-MH Coordination Agreement.

6.5.1.3 Governing Agreement for MPC and MH Coordination

This coordination procedure is established between MPC and MH pursuant to sections 9.011, 9.02, and 9.022 of the Interconnection, Facilities and Coordinating Agreement respecting Ridgeway-Shannon 230 kV Interconnection.

6.5.2. Purpose

The purpose of this coordination procedure is to coordinate Generation Interconnection Requests and Long Term Firm Transmission Service Requests where one of the three parties may be an Affected System. Each party will implement this procedure through Tariff and/or Business Practices under each party's respective tariff(s).

6.5.3. Definitions

- **Affected System**: a non-Host TSP whose transmission system may be reasonably expected to experience a non-trivial loading impact due to a TSR or GIR on a Host TSP's transmission system
- **Affected System Upgrades**: upgrades required to the Confirmed Affected System transmission system to accommodate the Host TSP GIR or TSR. The need for the Affected System Upgrade will be identified in the impact study and further defined in the Affected System facilities study
- **Business Practices**: a (set of) document(s) that implement certain obligations of the respective party and its tariff customer
- **Confirmed Affected System**: an Affected System that has been confirmed through either the Host TSP or the Affected System impact analysis that the Affected System has an

impacted facility due to a TSR or GIR on a Host TSP's transmission system as shown in the Host TSP impact study report

- **Generation Interconnection Request or GIR**: a request to interconnect or modify generation under the respective TSP's policies and procedures (MISO's tariff Attachment X (Generator Interconnection Procedures (GIP)), MPC's Large Generator Interconnection Procedures (LGIP) or Small Generator Interconnection Procedures (SGIP), or MH's Open Access Interconnection Tariff (OAIT))
- **Generator Interconnection Agreement or GIA**: an agreement documenting the terms of interconnection service between a TSP and its customer
- **Host TSP**: MH, MPC, or MISO that receives the GIR or TSR
- **Impact Study Agreement**: the agreements under each party's respective policies and procedures to evaluate the impact of the TSR or GIR
- **Long Term Firm Transmission Service Request (TSR)**: a request for long term firm transmission service across the TSP's transmission system under the respective party's tariff (MISO's tariff, MPC's Open Access Transmission Tariff (OATT), or MH's OATT)
- **MISO Definitive Planning Phase or DPP**: the final impact study phase for MISO GIRs as defined by the Business Practices under MISO's tariff
- **MISO M2 Milestone**: the MISO DPP entry milestone as defined by the Business Practices under MISO's tariff
- **Neighboring TSP(s)**: MH, MPC, and/or MISO that does not receive the GIR or TSR. General reference to any or all of the parties to this coordination language.
- **Network Upgrade**: upgrade required on the Host TSP transmission system to accommodate the GIR or TSR as defined by the parties' respective tariffs, policies or procedures
- **Remedial Action Scheme**: as defined by NERC standards
- **POR/POD**: Point of Receipt/Point of Delivery as defined by each party's respective tariffs

Transmission Service Provider or TSP – as defined by NERC standards

6.5.4. Scope

This section defines the GIRs and TSRs that are deemed in scope for this procedure. A GIR or TSR that is deemed in scope will be subject to the coordination procedures below. If the GIR or TSR is not deemed in scope, it is not subject to the coordination procedures below.

6.5.4.1 Large Generator Interconnections

A GIR is deemed in scope for this coordination procedure as follows:

i. All MISO North GIR for MISO
ii. All GIR for MPC
iii. All GIR for MH

For any GIR that falls within this scope, the Neighboring TSPs will be considered Affected Systems.

MISO North refers generally to the northern part of MISO, which is subject to change as members join or leave MISO. The red section in the picture[9] below captures the in-scope area for MISO at the time the agreement was executed.

[9] From MTEP 2014 - https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP14/MTEP14%20Book%201%20-%20Transmission%20Studies.pdf

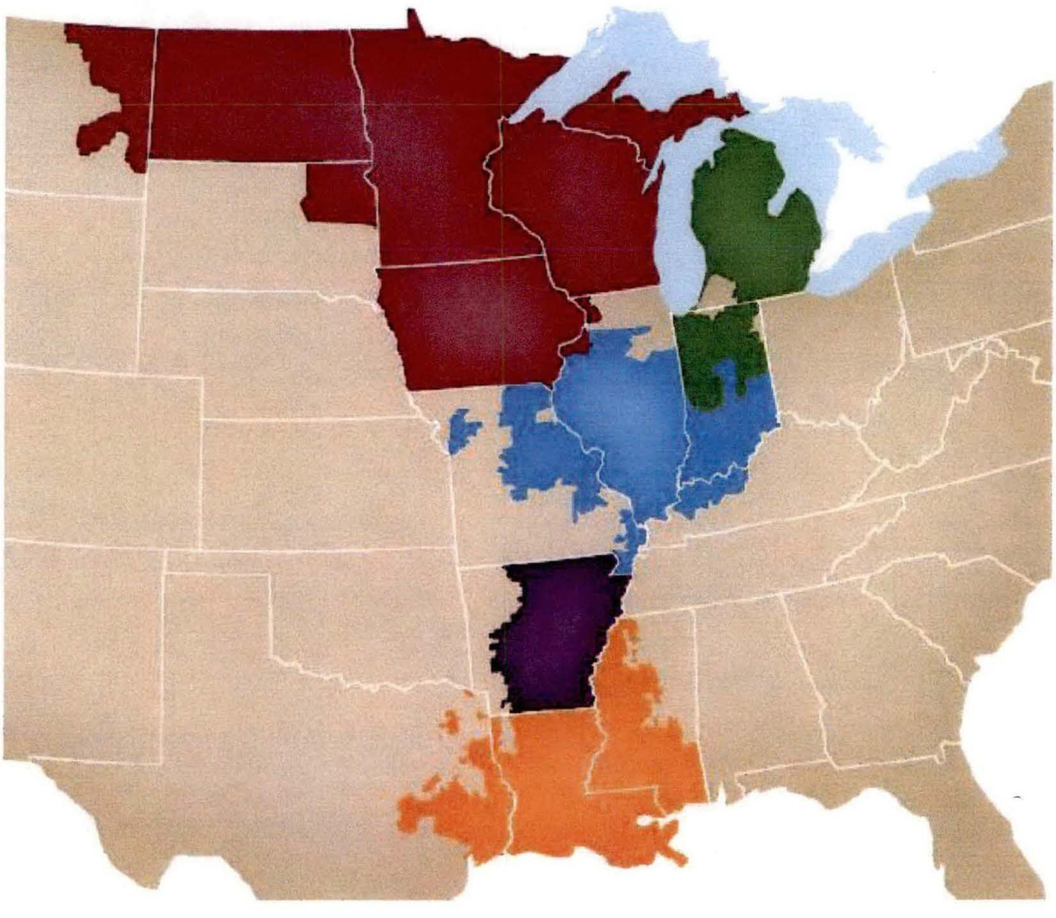


Figure 6-2 MISO Planning Regions

6.5.4.2 Small Generator Interconnections

If it is determined by the Host TSP that a GIR is potentially eligible for accelerated processing under the Host TSP's interconnection procedures due to its small size, the GIR will be deemed in scope for this coordination procedure as follows:

- All GIR for MISO interconnecting in the following Local Balancing Areas: GRE, MDU, MP, NSP, OTP
- All GIR for MPC

MH does not differentiate between small generator and large generator interconnections and therefore does not offer accelerated processing for small generator interconnections.

6.5.5. Procedure

6.5.5.1 Generation Interconnection Requests

MISO, MH, and MPC have agreed to the following process by which Generator Interconnection Request studies are conducted to determine the impacts of Generator Interconnection Requests on each other's transmission systems. Coordination with Affected Systems is required by the parties' respective policies and procedures. This joint coordination of Generator Interconnection Request studies serves to clarify the process by which that coordination is conducted for MISO, MH, and MPC.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

6.5.5.1.1 Queue Priority and Cost Allocation

For the purposes of performing impact studies, all parties will model higher queued and concurrently queued projects. Position in the queue is determined by:

- The date that a valid GIR is received under the MH tariff
  - For a group study conducted under the MH OAIT, the queue position of the group relative to MISO and MPC projects will be the date that the last valid GIR in the group study was received by MH
- The date that a valid GIR is received under the MPC LGIP or SGIP
  - For a cluster study conducted under the MPC LGIP, the queue position of the cluster relative to MISO and MH projects will be the date that the last valid GIR in the cluster was received by MPC

- The MISO M2 Milestone payment submission deadline per the MISO tariff.

MISO projects will not in any event be considered to have equal queue priority to a MH or MPC project, due to the fact that the MISO (M2) Milestone deadline is at a specific point in time. An MH or MPC Impact Study Agreement that is signed on the MISO (M2) Milestone deadline will have higher queue priority than the MISO project. An MH or MPC Impact Study Agreement that is signed the day after the MISO (M2) Milestone deadline will have lower queue priority than the MISO project.

MPC and MH projects will have the same queue priority if the Impact Study Agreements are signed on the same day. In this case, they will be treated as concurrent projects for cost allocation on common Network Upgrades and Affected System Upgrades.

Projects with a completed impact study or a GIA that was executed prior to the implementation of this jointly coordinated language between MH, MPC, and MISO will be treated as higher queued generators in the future interconnection studies.

The highest queued project (or group of projects in a group study) driving the need for an upgrade shall pay for the upgrades required to mitigate its impact on the transmission system, consistent with cost causation principles, unless the parties agree on another cost allocation that results in a more desirable outcome for the customers. The Neighboring TSP will provide cost of upgrades required on its system to the Host TSP for cost allocation amongst the generator interconnection projects using Host TSP's cost allocation methodology. In the case of concurrent MH and MPC projects, if projects are deemed to require the same upgrade, costs will be allocated pro rata based on each project's respective impact on the constrained element unless otherwise agreed to by MH and MPC.

6.5.5.1.2 Notice

The Host TSP will provide notice of GIRs identified in section 6.5.4 to the Neighboring TSPs:

- When a valid GIR is received by MPC;
- When a valid GIR is received by MH; and
- When the MISO M2 Milestone deadline has passed for MISO.

The Host TSP will send an email with details of the associated GIR project so that the Neighboring TSP can begin including the project in their models. The Host TSP will include the Neighboring TSPs in the ad-hoc study group for a Host TSP GIR impact study.

The Host TSP will also provide a similar notice to the Neighboring TSPs following a non-material modification or withdrawal of a GIR identified in section 6.5.4.

6.5.5.1.3 Impact Study Obligations

The Host TSP will monitor impacts on the Neighboring TSP's transmission systems in all Host TSP impact studies and provide the results to the Neighboring TSP's.

Results and any associated mitigations on the Host TSP's transmission system will be provided at the earliest possible date to allow for the Neighboring TSPs to consider the impacts identified on their own transmission systems.

When the Host TSP performs the impact study, the Host TSP will use reasonable efforts to monitor the affected system and:

- The MISO and the MISO transmission owner study and reinforcement criteria will apply to the monitoring of MISO transmission facilities;
- The MPC study and reinforcement criteria will apply to the monitoring of MPC transmission facilities; and
- The MH study and reinforcement criteria will apply to the monitoring of MH transmission facilities.

These potential impacts will be included in the Host TSP impact study report. The Host TSP will provide the Affected Systems the opportunity to validate the impacts on their transmission systems and identify mitigations.

Additionally, the Neighboring TSP's can each choose to study the impacts of the Host TSP GIR on their own transmission systems and send results to the Host TSP for inclusion in the final impact study report. The Host TSP will provide the necessary information and models so that Neighboring TSP's can perform these impact studies. The Host TSP will allow the Neighboring TSP the same amount of time to complete affected system studies as the Host TSP has scheduled for its own study. The Host TSP may request results slightly in advance of its own deadline in order to incorporate the Neighboring TSP's results into its own report. The Host TSP will allow the Neighboring TSP's extra time if requested and if the additional delay does not hinder timely completion of the Host TSP's impact study.

If the Affected System's policies allow for the sharing of study models, an Interconnection Customer can apply to obtain the study models from the Affected System by executing the required confidentiality agreements.

The Host TSP shall include in the Host TSP impact study report the impacts on the Affected System based on Affected System criteria. Any changes to the Affected System Criteria shall not be enforceable once the Affected System study has started. These impacts shall include:

- The minimum amount of interconnection service that can be granted without Affected System Upgrades,
- A description of the required system reinforcements,
- A planning level cost estimate, and
- Preliminary estimate of the in-service date of the system reinforcement.

The Host TSP will promptly share impact study reports with the Affected Systems upon completion.

6.5.5.1.4 Mitigating Host TSP GIR Impacts on the Confirmed Affected System's Transmission System

If the impact study confirms a constraint to interconnection service on an Affected System's transmission system, the Host TSP will require the customer to contact the Confirmed Affected System and make arrangements with the Confirmed Affected System to identify and construct facilities for mitigation of impacts. For required Affected System Upgrades on the Confirmed Affected System due to a Host TSP GIR, the Host TSP will require the interconnection customer(s) to follow all provisions delineated under the Affected System policies, procedures, and Business Practices. Required arrangements include but are not limited to signing the facilities study agreement and signing the Confirmed Affected System upgrades agreement to construct the mitigations identified in the Confirmed Affected System facilities study.

The Host TSP and Confirmed Affected System will promptly share facility study reports with each other upon completion.

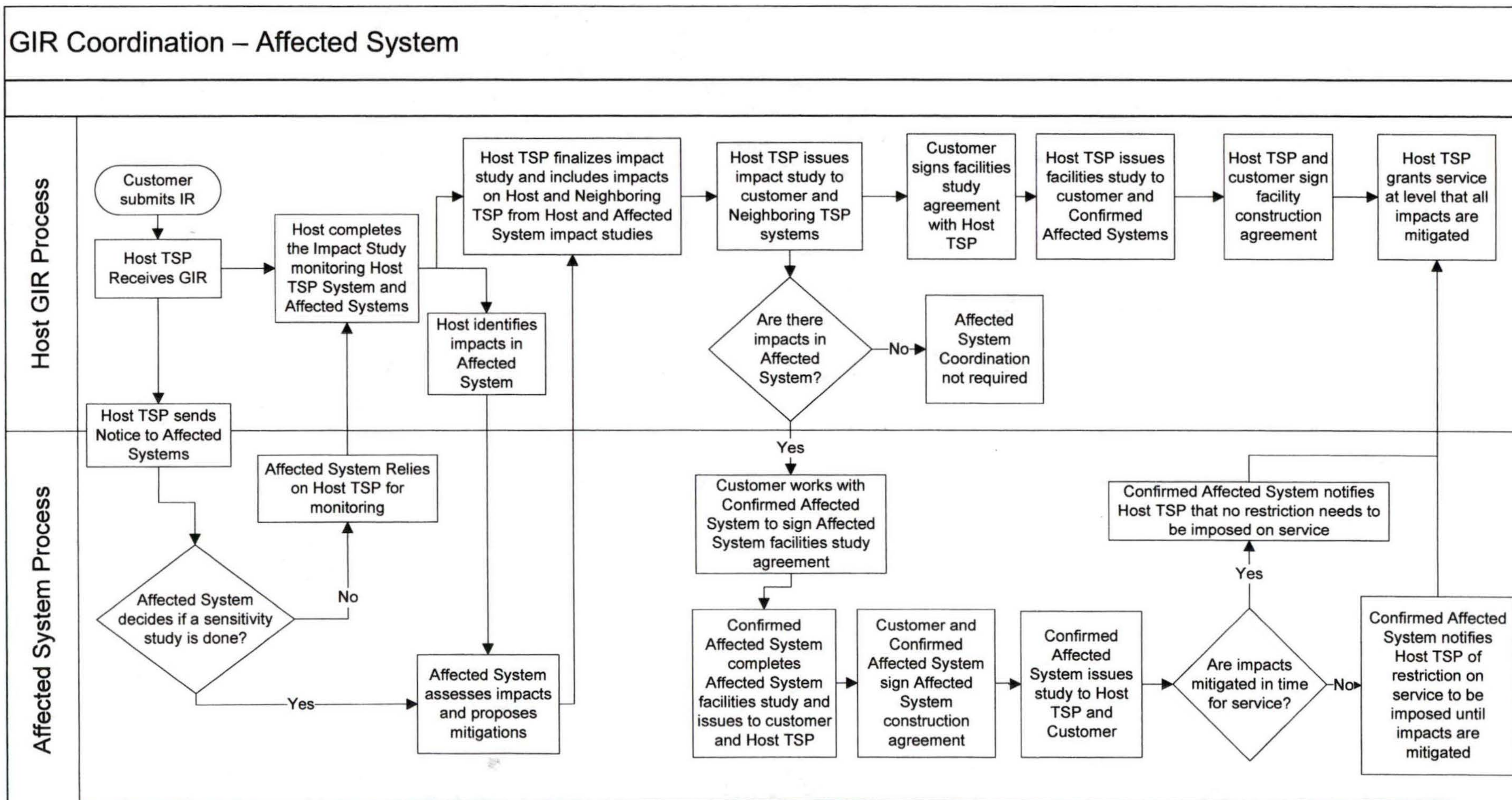
If generation interconnection projects are granted interconnection service by the Host TSP prior to completion of required Affected System Upgrades on the Confirmed Affected System, commercial operation shall be limited up to the amount at which there are no transmission constraints identified by the studies on the Confirmed Affected System(s) transmission system. The study to determine limitation is coordinated between the Host TSP and the Confirmed Affected System TSP. If one exists, the Affected System will provide operating limitation policies to the Interconnection Customer upon request.

6.5.5.1.5 Special Provisions for Accelerated Processing

For generators that are eligible for accelerated processing and are deemed to be in scope for this coordination procedure, the parties agree to the following special provisions:

- Notice will be provided to the Neighboring TSPs upon receipt of a valid GIR
- The Host TSP will inform the Neighboring TSPs of their study schedule deadlines and request that the Neighboring TSPs use good faith efforts to accommodate the Host TSP's accelerated schedule if the Neighboring TSP performs an Affected System study
- In the event that a Neighboring TSP is not able to complete an Affected System study in time to meet the Host TSP's study schedule, the Host TSP will continue in accordance with its posted procedures, making reasonable efforts to accommodate a late submission by the Neighboring TSP.

If a GIR that was potentially eligible for accelerated processing is later required to complete the standard interconnection process, the normal provisions of the agreement will apply.


GIR Coordination – Affected System
Host GIR Process
Affected System Process
Customer submits IR
Host TSP Receives GIR
Host completes the Impact Study monitoring Host TSP System and Affected Systems
Host TSP finalizes impact study and includes impacts on Host and Neighboring TSP from Host and Affected System impact studies
Host identifies impacts in Affected System
Host TSP issues impact study to customer and Neighboring TSP systems
Are there impacts in Affected System?
No
Affected System Coordination not required
Customer signs facilities study agreement with Host TSP
Host TSP issues facilities study to customer and Confirmed Affected Systems
Host TSP and customer sign facility construction agreement
Host TSP grants service at level that all impacts are mitigated
Host TSP sends Notice to Affected Systems
Affected System Relies on Host TSP for monitoring
Affected System decides if a sensitivity study is done?
No
Yes
Affected System assesses impacts and proposes mitigations
Yes
Customer works with Confirmed Affected System to sign Affected System facilities study agreement
Confirmed Affected System completes Affected System facilities study and issues to customer and Host TSP
Customer and Confirmed Affected System sign Affected System construction agreement
Confirmed Affected System issues study to Host TSP and Customer
Are impacts mitigated in time for service?
Yes
No
Confirmed Affected System notifies Host TSP that no restriction needs to be imposed on service
Confirmed Affected System notifies Host TSP of restriction on service to be imposed until impacts are mitigated

6.5.5.2 Compensation for Affected System Analysis (Applicable to MPC and MISO Only)

The Interconnection Customer will be responsible for the costs incurred by the Neighboring TSP for performing affected system analysis associated with system impact studies with the help of engineering consultants. A Host TSP will reimburse the Neighboring TSP using Interconnection Customer's study deposit funds upon receipt of an invoice from the Neighboring TSP. Only the direct costs of the engineering consultants will be included in the invoice.

6.6. Annual ERIS Evaluation and Annual Interim Deliverability Study

6.6.1. Scope

For all permanent GIAs with conditions and Provisional GIAs, an Annual ERIS evaluation will be performed which will identify the maximum level of injection available for the next Resource Adequacy Planning Year. In addition, MISO will also perform the same annual ERIS analysis for the following two years for information purposes only. Further, for all permanent GIAs with conditions with conditional ERIS that will eventually convert to ERIS and NRIS, an Annual Interim Deliverability analysis will be performed which will identify the maximum level of conditional NRIS available for the next Resource Adequacy Planning Year, up to the level of eventual NRIS. In addition, MISO will also perform the same Annual Interim Deliverability analysis for the following two years for information purposes only. If a project has explicit conditions associated with MTEP Appendix A projects, listed in their existing GIA, the Annual ERIS and Annual Interim Deliverability Studies will be applicable from the time of their Commercial Operation Date until those explicit conditions are met.

6.6.2. Eligibility and Timing of Studies

The Annual ERIS and Annual Interim Deliverability study for the next Planning Year will be completed by October 31st of every calendar year. The informational results for the following two years will be completed by October 31st of every calendar year. The results of the Annual Interim Deliverability Study for the next immediate planning year will be documented in the MISO Interconnection Service Workbook.

The Annual ERIS and Annual Interim Deliverability Analysis for the next Planning Year will include only those projects with Generator Interconnection Agreements that have been executed by April 15th of the study calendar year. The Annual ERIS and Annual Interim Deliverability analysis for the following two Planning Years, provided for informational purposes only, will include all Generator Interconnection Agreements that have been executed by June 15th of the study calendar year. In addition, all generators that are subject to the Annual studies must be online during the Planning Year being analyzed.

6.6.3. Annual ERIS Evaluation

The maximum amount of injection available for the studies generator will be identified for the next three (3) Planning Years.

6.6.3.1 Methodology

The Annual ERIS evaluation would include the following suite of reliability analyses that will be carried out on both the Summer Peak and Shoulder Peak cases:

i. Thermal Analysis,
ii. Steady State Voltage Analysis,
iii. Transient Stability Analysis

The constraint criteria for the above analyses will be consistent with the Generator System Impact Study criteria as laid out in Sections 6.1.1.1.6, 6.1.1.2 and 6.1.2.4. This study will not identify any Network Upgrades on the Transmission System. The injection limit from this analysis will be determined on a pro rata basis based on the nameplate of the generators under evaluation.

6.6.3.2 Base Case Assumptions

The Summer Peak and Shoulder Peak Base Cases for the Annual Interim ERIS evaluation will be reflective of the Generation and Transmission System expected to be in-service at the start of the Planning Year. The individual cases for following two years will be reflective of the Transmission and Generation that is expected to be in service at the start of those individual Planning Years.

6.6.3.3 Load Levels and Generation Dispatch

The Summer Peak and Shoulder Peak case Load Levels and Generation Dispatch will be consistent with Load Level and Dispatch assumptions used for the respective MTEP Cases as per Section 3.3 of MISO Transmission Planning BPM 020. The Generator Interconnection Requests under the consideration for Annual Interim ERIS evaluation would be dispatched consistent with the existing Section 0

6.6.4. Annual Interim Deliverability Study

The maximum amount of conditional NRIS available, for the next three (3) Planning Years, will be identified. In addition, the Annual conditional NRIS value will be capped at the lower of a) Annual ERIS value or b) Annual Interim Deliverability study NRIS value.

6.6.4.1 Methodology

The Interim Deliverability Study will follow the MISO deliverability methodology as documented in the deliverability whitepaper and can be found at:

https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=90065

The Interim Deliverability Analysis will be performed on the Summer Peak Case used for the Annual ERIS evaluation analysis.

6.6.5. Exit from Annual ERIS and Annual Interim Deliverability Studies

Any Interconnection Project with explicit conditionality associated with MTEP Appendix A projects, listed in their existing GIA based on the A10 process (Section 6.2.4), will exit the Annual ERIS and Annual Interim Deliverability Studies when those explicit conditions have been met and when the obligations to direct assigned upgrades to the GI project(s) have been met.

6.6.6. Annual ERIS Studies and QOL Coordination

The amount of ERIS injection that clears the Annual ERIS evaluation for the next Planning Year will not be subject to the QOL studies for all 4 quarters of that year. Any ERIS injection that does not clear the Annual ERIS evaluation for the next Planning Year will be included in the QOL studies for all 4 quarters of that year. The customer may choose not to be included in the QOL studies if they wish to be limited by the Annual ERIS evaluation results for all 4 quarters of that year.

6.7. Modification of the Characteristics for Existing Generating Facilities

If a planned modification to an Existing Generating Facility (with unsuspended interconnection rights) is expected by the Interconnection Customer (or generator owner) to have material (adverse) impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, or ii) dynamic system stability and response, or iii) short-circuit capability limit; the Interconnection Customer shall submit a request in writing to MISO for a substantive modification screening prior to performing any permanent[10] modification[11,12] to an Existing

[10] Temporary modifications do not require changes to the GIA. Temporary modifications made while waiting on the comparable part to be delivered and modifications made as a result of equipment failure to support continued reliability may not be "comparable." However, such modifications do not require changes to the GIA, as they are a part of an owner's routine maintenance and/or equipment failure processes and are not subject to MISO review.

[11] Any modification that may result in an increase in net injection above the existing Interconnection Service will require a new Interconnection Request to be submitted to MISO prior to an increase in actual injection at the POI. A request to tear down an existing Generating Facility and construct new Generating Facility at the same location should follow Generator Replacement procedures. A request to add a separate Generating Facility at the same POI with the intention of utilizing existing interconnection service should follow Net Zero procedures.

Generating Facility. The request shall be in the form of a letter describing the planned changes to the Existing Generating Facility and all relevant data. The request shall be submitted to MISO at the following address:

Director, Resource Utilization
MISO
720 City Center Drive
Carmel, IN 46032

Generating Facility maintenance that requires replacement of components with newer comparable components to ensure continued or enhanced reliable operation of the Generating Facility will generally be considered to have *de minimis* impact on the transmission system. It is the Interconnection Customer's responsibility to support any determination that the planned modification is not expected to result in degradation of transmission system reliability. The evidence to support this engineering judgment may be an assessment that is performed by the Interconnection Customer, Transmission Owner (TO), or a third party.

For on-going generator maintenance, where the replacement components are comparable and impacts are expected to be *de minimis*, there is no need for the submission of information to MISO for determination of material (adverse) impacts. In cases where replacement components are not comparable, MISO will determine if the change is a substantive modification (i.e. potential Material Modification).

A determination of whether a planned change has a *de minimis* impact on the transmission system shall be made using good engineering judgment and shall be based on the decision made or opinion rendered by a qualified engineer. In making this determination, the qualified engineer shall take into account all available data and rely on his or her experience with the generation technology and transmission system and knowledge of NERC standards. Additionally, the Interconnection Customer may request a meeting with MISO and the TO prior to submitting a request for Generating Facility modification evaluation to discuss the planned change and any need for additional studies.

If MISO determines that the requested change is a substantive modification (*i.e.*, a potential Material Modification), the Interconnection Customer will be required to submit a new Interconnection Request to MISO for evaluation if the requested change is a Material

[12] Fuel conversion that does not involve complete tear down of an existing Generating Facility will be eligible for generator modification process.

Modification. The Interconnection Customer may submit additional information and/or analyses for MISO to consider in its review.

Where the Interconnection Customer seeks MISO's determination of the impacts of a planned change on the Transmission System, the details of MISO's substantive modification screening and Material Modification evaluation are explained in the sections below.

6.7.1. Milestones

If an Interconnection Customer submits an application to MISO for a substantive modification screening without any documentation of the impacts of the planned change on the Transmission System relative to the criteria defined above, the required deposits for this evaluation is $10,000. Any amount of this deposit that is not used toward the evaluation or future study would be refunded to the Interconnection Customer.

A deposit is not required if the Interconnection Customer submits engineering studies supporting a determination that the planned changes is not substantive modification (i.e. the change will not adversely impact the Transmission System). However, a fee may be required at a later date to reflect the cost of review or a study deposit may be collected if the analysis submitted by the Interconnection Customer is incomplete or does not demonstrate that the planned change is not substantive modification.

6.7.2. Substantive Modification Screening

Requests submitted to MISO will be evaluated for any change in operating characteristics of the Existing Generating Facility that is different than what was studied in the interconnection process or reflected in its interconnection agreement. The Interconnection Customer may submit its studies/analyses that are performed by a qualified subject matter expert to MISO for consideration in its review. Like-for-Like (or comparable) replacements and refurbishments of existing equipment are not substantive modifications, and MISO's evaluation of these equipment is not required unless the Interconnection Customer anticipates that such changes may have material impact on the Transmission System, per the criteria defined below.

The following criteria will be used to determine whether the change to the characteristics of an Existing Generating Facility is a substantive modification (a potential Material Modification):

- Any change in expected output of the Generating Facility that is higher than what was studied in the interconnection process
- An increase in short circuit current that degrades transmission system reliability

- Angular stability performance and dynamic response that is not the same or better than existing
- Violation of steady-state thermal or voltage limits caused by the planned change

If necessary, MISO will perform short circuit and/or transient stability analysis (similar to the analysis included in System Impact Study, Section 6.1.2) to determine whether the requested modification is a substantive modification (potential Material Modification).

MISO will respond to the Interconnection Customer within 30 days and provide the path for the Interconnection Customer to amend their GIA, as necessary, or to submit a new Interconnection Request for Material Modification evaluation.

6.7.3. Material Modification Evaluation

Once the Interconnection Customer submits an Interconnection Request for Material Modification evaluation, MISO will perform necessary studies (one or more of Steady State analysis, Short Circuit analysis and Stability analysis as described in Section 6.1) within 90 days to determine if the planned modification is a Material Modification and provide a publicly posted report. If the planned change is a Material Modification, the Interconnection Customer will have an opportunity to enter its planned change in the subsequent DPP cycle. If the planned change is non-material, MISO will work with the Interconnection Customer to issue an amended GIA (*pro forma* GIA).

6.7.4. Applicability of Substantive Modification Screening and Material Modification Evaluation

If the Interconnection Customer is certain that the planned change to the Existing Generating Facility would constitute a Material Modification, the Interconnection Customer can enter the DPP cycle in MISO's Generator Interconnection queue by submitting a new Interconnection Request without submitting a request for substantive modification screening or a Material Modification evaluation.

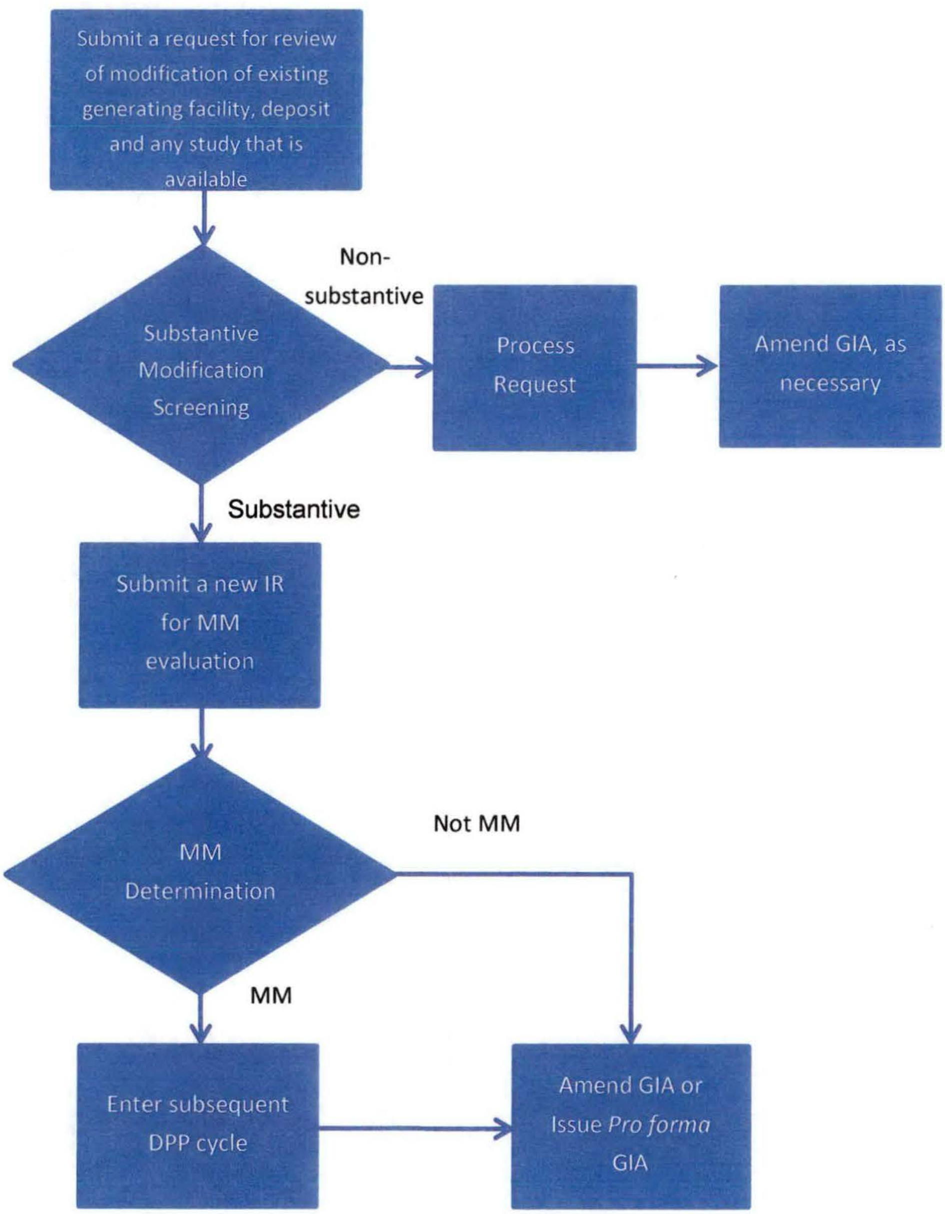


Figure 6-3 Flowchart describing Generating Facility modification evaluation and Material Modification determination

7. Post – GIA Phase

The following sections describe various activities in project development after the Generator Interconnection Agreement is executed.

Initial Payment

The Interconnection Customer is required to pay the initial payment of either 1) twenty percent (20%) of the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades identified in the GIA if the Generator In-service date is within five (5) years of executing the GIA; or 2) ten percent (10%) if it is beyond five (5) years; or 3) the total cost of Network Upgrades, Transmission Owner Interconnection Facilities, Transmission Owner's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades in the form of security. The initial payment shall be provided to Transmission Owner by the Interconnection Customer within the later of a) forty-five (45) Calendar Days of the execution of the GIA by all Parties, or b) forty-five (45) Calendar Days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by the Interconnection Customer, or c) forty-five (45) Calendar Days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by the Interconnection Customer. If the Interconnection Customer made its Milestone payments in the form of cash and the Interconnection Customer elects a cash initial payment, then MISO shall transfer those funds to the Transmission Owner on the Interconnection Customer's behalf.

Limited Operation

If any of the Transmission Owner's Interconnection Facilities, Network Upgrades, or Transmission Owner's System Protection Facilities, Distribution Upgrades or Generator Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Transmission Owner's Interconnection Facilities, Network Upgrades, Transmission Owner's System Protection Facilities, Distribution Upgrades or Generator Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and the GIA. The maximum permissible output of the Generating Facility will be updated on a quarterly basis if the Network Upgrades necessary for the interconnection of the Generating Facility pursuant to the GIA are not in service within six (6) months following the Commercial Operation Date of the Generating Facility as specified in Appendix B of the GIA. These quarterly studies will be performed using the same methodology set forth Section 6.2.9 of this BPM for Provisional Generation Interconnection Agreements. These quarterly updates will end when all Network Upgrades necessary for the interconnection of the Generating Facility pursuant to this GIA are in service.

7.1. Suspension

After the execution of the Interconnection Agreement, the Interconnection Customer is expected to meet the Milestones and construction schedule as established in the Interconnection Agreement. In certain conditions, Interconnection Customer has the option to suspend the construction of the Network Upgrades and Interconnection Facilities based on narrowly defined criteria. The following rules and conditions will govern the suspension of a project in the post-IA phase.

- Permitted only for Force Majeure reasons: "Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by the Party claiming Force Majeure."
- When coming out of suspension with only partial construction resulting in reduced project capacity, recovery eligibility is reduced on a pro-rata basis relative to the new size of the project
- Will require an up-front payment equivalent to greater of Network Upgrade costs or $5 million
- Suspended IRs may be revisited periodically to ensure Interconnection Customer is working toward coming out of suspension

When emerging from suspension, the Interconnection Customer must provide written notice to the MISO noting the date as of which the request is no longer suspended along with notice of any changes to the Interconnection Facilities and/or Generating Facility as compared to the description in the Interconnection Agreement or the studies performed in support of the Interconnection Agreement. MISO will restudy the project coming out of suspension with the transmission assumptions that exist on the day it receives such notice. MISO will require a reasonable study deposit to perform such studies. Failure to provide the needed data and deposit at the time of notice may lead to the IC being declared in Breach of Agreement.

7.2. Construction

The project construction will take place according to the construction schedule established in the Generator Interconnection Agreement. In the event, a project goes into suspension the required Network Upgrades and Transmission Owner Interconnection Facilities will be constructed on the schedule described in the appendices to the GIA, except for the following reasons:

i. Construction is stopped by a Governmental Authority;
ii. Network Upgrades are not needed for another project; or
iii. The MISO or Transmission Owner determines that a Force Majeure event prevents construction.

Interconnection Customer will closely coordinate the various construction activities with the Transmission Owner to make sure the appropriate design standards are followed and technical specifications of the Interconnection Customer constructed facilities match with that of the Transmission Owner constructed facilities.

7.3. Testing

Interconnection Customer or the designated Market Participant will notify MISO with a test plan in advance of conducting the tests for the Generating unit(s). The notification should be provided by completing the Pre-commercial Generation Test Notification form located in Appendix D of this BPM and submitting it to MISO Real Time Operations at least five (5) Business Days prior to the first testing date. The MISO Operations will work with the Asset Owner/Market Participant and approve a schedule to conduct the tests. The testing process will also be coordinated with Transmission Operators.

7.4. Registration of Asset with MISO

The Market Registration BPM describes the details of Asset Registration.

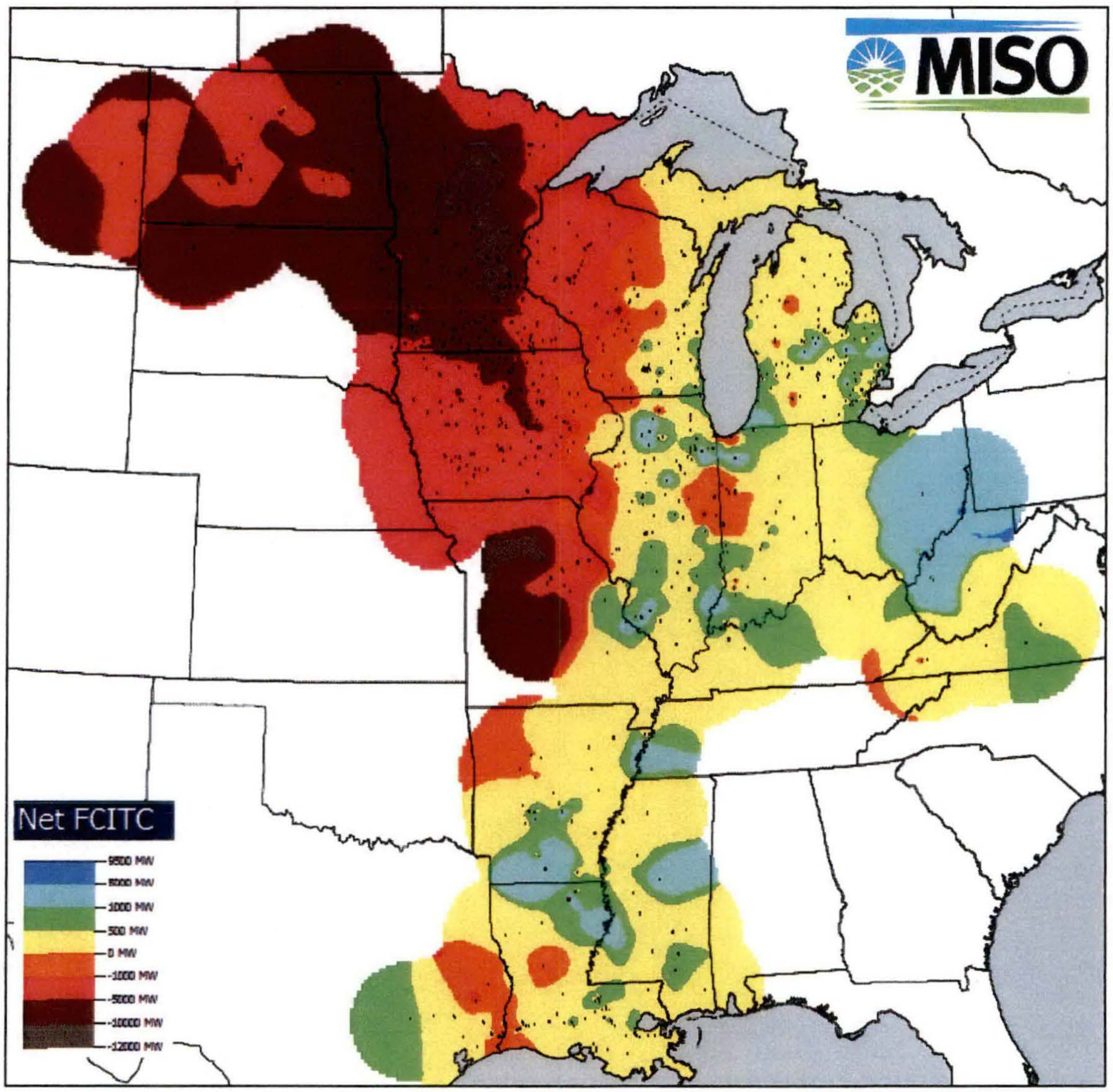
7.5. Inclusion in Network Model

The Network and Commercial Model BPM describes the steps required to submit the information to include a generator in Network Model.

7.6. Commercial Operation

Interconnection Customer must provide notification to the MISO after the project achieves Commercial Operation. Such notification is provided in the form of Appendix E to the GIA and must be received by the MISO within thirty (30) days of Commercial Operation date in order to initiate any refund. The notification should also include as built modeling data of the plant. Attachment A of the application can be used to provide such data. The MISO will settle the project account and provide a final invoice to the Interconnection Customer within thirty (30) days of receiving the Appendix E to GIA.

Appendix A
Sample Contour Map



This is a sample contour map generated using an off-the-shelf MTEP 2016 summer peak model. Estimated time through interconnection queue does not include construction time.

Appendix B

Generator Interconnection Ad Hoc Information Session Request Form

I. Interconnection Customer

Name: ______________________________
Title: ______________________________
Company Name: _______________________
Address: _____________________________
Phone No.____________________________
Email address _______________________

II. Project Details

Project Size (MW) ______________
No. of units/rating______________
Fuel type: ____________________
Desired ISD: __________________
Anticipated date to enter the Queue____________

III. Site

County: ______

State: ________

Area Transmission Owner(s) _________________

POI: ____

(If not identified, list all options that are being considered)

Distance from the nearest substation or transmission line______________________

Available Connection Voltage(s) ___________________________

Site Control _________ (Yes/No)

ROW Required for Interconnection Facilities? _____________ (Yes/No)

IV. Specific Questions for the Transmission Provider/Transmission Owner (use a separate sheet, if required)

1.

2.

3.

4.

V. Information Session is requested by

Signature: ______________________________

Name (print or type):____________________________

Title: ______________________________

Company Name: _______________________

Address: ______________________________

Phone No.____________________________

Email address _______________________

This form can be faxed or mailed to the following address:

Midcontinent Independent System Operator, Inc.
Attn: Transmission Access Planning
720 City Center Drive
Carmel, IN 46032
Fax 317-249-5358

Appendix C

Reserved

Appendix D

Pre-Commercial Generation Test Notification Form

The following form would need to be submitted to MISO Real Time Operations at least five **(5)** Business Days prior the first date of testing.

Project Number:

Project Name:

Point of Interconnection:

Dispatcher Contact Information:

Date	Start Time (in EST)	End Time (in EST)	Expected MW Output	Expected MVAR Output (Only needed if beyond normal power factor)

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION CASE NO. 2017-00384

Response to the Office of the Attorney General's Supplemental Request for Information dated August 17, 2018

September 14, 2018

Item 3) *Refer to Big Rivers' Response to the Sierra Club's Initial Request for Information, Items 22 and 23. Big Rivers states that solar construction costs are projected to decrease in the futures but that they "are currently not competitive with other power source options."*

a. Explain how close the solar construction costs would need to be to other power sources in order to be considered competitive.

b. Big Rivers states that it will continue to evaluate solar options, and the Table in response to Item 23.b shows Solar-Fixed construction costs declining every year from 2017-2031 while Combined Cycle and Combustion Turbine costs increase each year. Fully explain how Big Rivers will approach its continuing evaluation of solar generation as those costs continue to fall.

Response)

a. The solar total operation cost (construction cost and O&M costs) would need to provide an economic benefit (provide a least-cost option in the LT Plan model) for solar to be built.

b. Please see Big Rivers' response to Item 15 of Ben Taylor and the Sierra Club's supplemental request for information in this case. That response notes that the Solar Energy Industries Association ("SEIA") states solar build costs actually increased over the second half of 2017. Also, see the SEIA link in that response. Big Rivers will continue to monitor solar cost and utilize *PLEXOS® LT Plan* models for determining if solar generation would provide an economic benefit.

Witness) Duane E. Braunecker

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to the Office of the Attorney General's
Supplemental Request for Information
dated August 17, 2018

September 14, 2018

Item 4) *Refer to Big Rivers' Response to PSC Item 1-6, which references Big Rivers' "April 4, 2017 Progress Report in response to the 2014 Focused Management and Operations Audit." Provide a copy of that April 4, 2017 Progress Report.*

Response) Please see Big Rivers' response to Item 1a of Ben Taylor and the Sierra Club's supplemental request for information in this case.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Response to the Office of the Attorney General's
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dated August 17, 2018

September 14, 2018

Item 5) *If Coleman was to return to service, what cost effect would there be on Wilson and the Green units, especially with regard to any applicable air pollution regulation credits?*

Response) Each unit is given NO_X and SO_2 allocations individually, so there will be no change to Wilson and Green units' allocations if Coleman were returned to service. Big Rivers' emissions as a system are required to meet its total system allocations and if Coleman were returned to service, there would be increased NO_X and SO_2 emissions. If system allocations are not enough to meet emissions, then compliance with the system NO_X and SO_2 allocations could be achieved by any combination of adding new emission control systems, limiting generation volume or purchasing allowances. The cost effect for meeting the system NO_X and SO_2 allocations would be included in the decision on whether to return Coleman to service as coal-fired or natural gas fired units.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

**Response to the Office of the Attorney General's
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dated August 17, 2018**

September 14, 2018

Item 6) *Provide a quantification of any air pollution credits that will arise from the retirement of the HMPL units.*

Response) The retirement of the HMPL units will not increase the number of air pollution credits. Allowances will be awarded to the units for approximately five years after the last date of operation of the units.

Witness) Dr. Thomas L. Shaw

BIG RIVERS ELECTRIC CORPORATION

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September 14, 2018

Item 7) *Under what circumstances does Big Rivers contemplate producing a study of costs necessary to achieve compliance with the CSAPR?*

a. Does Big Rivers believe it will ever have to spend additional sums to meet compliance with the CSAPR? If so, describe in complete detail.

Response) Big Rivers does not contemplate it ever being necessary to produce a study of costs to achieve compliance with the Cross State Air Pollution Rule ("CSAPR").

a. Yes. Big Rivers believes it will have to spend additional sums to meet compliance with the CSAPR. These additional sums are likely to be for maintaining/repairing compliance equipment and purchasing allowances as banked credits are depleted.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2017-00384

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dated August 17, 2018

September 14, 2018

Item 8) ***Refer to Big Rivers' response to the Attorney General's Initial Request for Information 1-7 (e). Does Big Rivers realistically believe that MISO market prices for both capacity and energy ever could support returning one or more of the Coleman units to service? If so, explain in detail.***

Response) Yes, Big Rivers believes that MISO market prices for both capacity and energy could support returning one or more of the Coleman units to service if the correct combination of conditions occurred. The conditions would include increased natural gas prices, decreased natural gas availability, increased industrial load, the retirement of other utilities' generation assets and/or easing of environmental regulation of coal-fired generation.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION CASE NO. 2017-00384

Response to the Office of the Attorney General's Supplemental Request for Information dated August 17, 2018

September 14, 2018

Item 9) *Refer to Big Rivers' response to the Attorney General's Initial Request for Information 1-7 (g). Provide the staffing levels necessary to return one or more of the Coleman units to service, together with annual costs thereof for all such FTEs.*

Response) In reference to Big Rivers' response to Item 7g of the Office of the Attorney General's initial request for information, the staffing levels necessary to return one or more of the Coleman units to service and the annual costs thereof for all such FTEs are shown in the table below. Staffing levels and costs are approximations only.

Big Rivers Electric Corporation Staffing Levels and Annual Costs to Return Coleman Plant to Service		
	Staffing Level	FTE Annual Cost
Coleman Unit 1	72	[redacted]
Coleman Unit 1	28 additional	
Coleman Unit 1	4 additional	
Total All Coleman Units	104 total	

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to the Office of the Attorney General's
Supplemental Request for Information
dated August 17, 2018

September 14, 2018

Item 10) *Reference Big Rivers' response to the Attorney General's Initial Request for Information 1-7 (i), which references the KPDES requirement for a CWA § 316(b) study to be started within six months of any restart of Coleman. How long does Big Rivers believe it would take to complete such a study?*

Response) Big Rivers estimates one year to complete the study.

Witness) Dr. Thomas L. Shaw

BIG RIVERS ELECTRIC CORPORATION

2017 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2017-00384

Response to the Office of the Attorney General's
Supplemental Request for Information
dated August 17, 2018

September 14, 2018

Item 11) *In the event that any currently operating Big Rivers unit should require new pollution control equipment, does Big Rivers believe any such unit can remain price competitive with gas combined cycle units in the MISO markets? Explain in full detail.*

Response) Big Rivers will perform appropriate economic analyses as new pollution control equipment is required, to determine the most cost efficient option to meet its capacity and energy obligations.

Witness) Michael T. Pullen