ORIGINAL

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
BIG RIVERS ELECTRIC CORPORATION	)	**Case No.**
FOR ENFORCEMENT OF	)	**2019-00269**
RATE AND SERVICE STANDARDS	)	

Responses to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Requests for Information dated June 18, 2020

FILED: June 29, 2020

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

VERIFICATION

I, Robert W. ("Bob") Berry, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W Berry
____
Robert W. ("Bob") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. ("Bob") Berry on this the 29th day of June, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
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VERIFICATION

I, Michael W. ("Mike") Chambliss, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael W. Chambliss

Michael W. ("Mike") Chambliss

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael W. ("Mike") Chambliss on this the 29th day of June, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ______

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

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VERIFICATION

I, Mark J. Eacret, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 29th day of June, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

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VERIFICATION

I, Michael T. ("Mike") Pullen, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael T. Pullen
Michael T. ("Mike") Pullen

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael T. ("Mike") Pullen on this the 29th day of June, 2020.

Joy P. Parsley
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

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VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry,

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 29th day of June, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ____________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
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June 29, 2020

Item 1) ***Is it Big Rivers' position that Big Rivers is the owner of Station Two?***

a. If no, what authority does Big Rivers rely upon for the proposition that Big Rivers is entitled to control the scope and duration of decommissioning Station Two?

Response) No.

a. Please see Big Rivers' Application. Big Rivers believes that decommissioning is consistent with Commission precedent and prudent utility practice. The cost allocation for decommissioning is set forth in Paragraph 8 to the 1993 Amendments and Mr. Pullen's Testimony, 77.24% Big Rivers/22.76% Henderson. But Big Rivers cannot unilaterally demolish the City's property. If the City instead elects retirement-in-place, then Big Rivers would have no cost responsibility. Subject to Commission approval under its authority to enforce obligations arising out of the Station Two Contracts, Big Rivers will perform retirement in place activities and then bill the City for the full cost under the procedure set forth in Mr. Smith's Testimony at page 17.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 2) ***Please identify the legal and/or regulatory authority which mandates the time frame in which decommissioning must be completed following closure of a fossil-fuel plant.***

Response) The United States Environmental Protection Agency ("EPA") (*see* 40 CFR Part 257) mandates surface impoundment closure within five years due to Station Two's ash pond's failure to meet certain location restrictions. The Station Two ash pond must be decommissioned and closed no later than April 17, 2024. Please see the attached letter to Chris Heimgartner regarding the requirements to close the Station Two ash pond.

Big Rivers believes that beyond the time frame required to decommissioning the Station Two ash pond within the regulatory requirements, it is prudent for Big Rivers and Henderson to proceed immediately to decommission and dismantle the Station Two facilities in order to reduce the ongoing and total costs to their rate payers. As explained in the Direct Testimony of Jeffrey T. Kopp at page 9:

> In my experience I have found that retiring in place is not a cost-effective long-term scenario when the carrying costs are taken into account.

When we have prepared cost estimates to evaluate these options, we have found that typically in five to seven years more money will be spent on carrying costs during the time a unit is in a retired in place condition than would be have been spent to fully demolish equipment and structures and perform site remediation activities. Furthermore, the equipment and structures cannot remain in perpetuity and will be required to be torn down at a future date as they reach end of life.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

April 28, 2020

Mr. Chris Heimgartner
General Manager
Henderson Municipal Power & Light
100 Fifth Street
P.O. Box 8
Henderson, KY 42419-0008

RE: Closure of Station Two Ash Pond

Dear Chris:

This follows up my letter to Ken Brooks of December 7, 2018, regarding the closure of the Henderson Municipal Power & Light (HMPL) Station Two ash pond. As you are aware, the ash pond is subject to regulation as a disposal unit for coal combustion residuals (CCR) under the rule codified by the U.S. Environmental Protection Agency (EPA) at 40 CFR Part 257 (the "CCR Rule"). As explained in my previous letter, the CCR Rule established certain location restrictions for regulated ash ponds that the Station Two ash pond does not meet, and this circumstance triggered the requirements to (i) cease all further disposal of waste in the pond and commence closure by April 17, 2019, and (ii) complete closure of the pond within five years thereafter. See 40 CFR § 257.101(b)(1)(ii). Disposal of CCR in the Station Two ash pond ceased when the plant was permanently shut down as of February 1, 2019. I am writing to you today to address the remaining obligation to complete the pond closure activities.

The closure obligations under the CCR Rule apply to "the owner or operator" of a regulated CCR disposal unit. At this time, the City of Henderson is the sole owner and operator of the HMP&L Station Two ash pond. Section 13 of the August 1, 1970, Power Plant Construction and Operation Agreement ("Construction and Operation Agreement") addresses "Operation, Maintenance, and Control" of Station Two. Section 13.1 states: "Except as otherwise provided herein, the City shall have full ownership, management, operation and control of its Station Two." Station Two is defined in Section 2.2 of that agreement to include the generating facility "and all auxiliary facilities, joint use facilities (provided by City) and other related facilities." As confirmed by a letter addendum to the 1993 amendments to the Construction and Operation Agreement and the companion Joint Facilities Agreement (the "Contract Amendments"), the Station Two ash pond is a "joint use facility" that was "provided by and owned by the City." Section 4.1 of the Joint Facilities Agreement states that "[T]itle to those joint use facilities or portions thereof provided by City will remain in City." The City's status as owner and operator of the Station Two ash pond is thus plainly evidenced by these agreements.

These agreements also make clear that Big Rivers is no longer an operator of the Station Two ash pond. Pursuant to Section 13.2 of the Construction and Operation Agreement, Big Rivers agreed to provide "all operating personnel, materials, supplies, and technical services required for the continuous operation of the City's Station Two." These operational services were to be provided by Big Rivers only "during the term of this agreement" and "as an independent contractor" and "subject to City's ownership, management, and control." As you are aware, Section 1 of the 1998 amendments to the Station Two Contracts provided that the Construction and Operation Agreement would terminate once the Station Two units were no longer capable of the normal, continuous, reliable operation for the economically competitive production of electricity; however, the parties agreed Big Rivers would, and the Public Service Commission authorized Big Rivers to, continue to operate Station Two under the terms of the Station Two Contracts until February 1, 2019, when the City retired Station Two. Accordingly, the Construction and Operations Agreement was terminated as of May 1, 2019, which was 90 days following the permanent shut down of Station Two generating operations on February 1, 2019. Likewise, in accordance with Section 8.1 of the Joint Facilities Agreement, the terms of that agreement expired with respect to the Station Two ash pond upon the shutdown of Station Two on February 1, 2019, as of which date neither Big Rivers nor the City continued to operate or maintain a generating station served by the ash pond. Big Rivers therefore has no existing contractual obligation or legal right to act as operator of the Station Two ash pond. In particular, Big Rivers has no existing contractual obligation or legal right to undertake construction work that would physically intrude upon or alter the ash pond structure -- which is owned by the City -- as would be required to complete closure of the pond in accordance with the CCR Rule.

As noted in my letter of December 18, 2018, Big Rivers prepared a closure plan for the Station Two ash pond in 2016 as then required by the CCR Rule. That plan provided that closure would occur by dewatering and capping the unit in place. Dewatering of the pond has already commenced as a result of the continued discharge of effluent from the pond as authorized under the Kentucky Pollution Discharge Elimination System permit held by Big Rivers for the Green/Reid/Henderson Station Two power plant complex (thereby satisfying the requirement to have initiated closure by April 17, 2019). For the reasons explained above, however, it is the City's sole responsibility to take all remaining actions necessary to complete closure of the Station Two ash pond.

While it is the City's obligation to conduct the remaining closure actions, Big Rivers will reimburse the City for Big Rivers' share of the costs of those actions as Station Two decommissioning costs in accordance with the terms of Section 8 of the Contract Amendments (provided that the City acknowledges its own obligation under this provision to share in the Station Two decommissioning cost).

Finally, we want to make sure that the record accurately reflects the current ownership and operational status of the Station Two ash pond. Accordingly, unless the City initiates good faith discussions regarding a possible closure services agreement in the near future, Big Rivers intends to provide notice to EPA and other interested parties through a posting on the company's public website that Big Rivers is no longer an operator of the Station Two ash pond and that all future compliance obligations under the CCR Rule with respect to the ash pond are the responsibility of the City.

Respectfully,

Mike Pullen
Executive Vice President of Operations
Big Rivers Electric Corporation

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
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Item 3) ***Refer to Big Rivers' Response to Item No. 31 of Henderson's First Request for Information and Big Rivers' Response to Item No. 73 of Henderson's First Request for Information. Please state the basis of your position that Big Rivers is not responsible for a share of costs associated with a retirement-in-place scenario.***

a. Please state the basis of your position that Big Rivers is not responsible for a share of ash-pond closure costs in the event of a retirement-in-place scenario.

Response) Henderson is the sole owner of Station Two, including the Station Two ash pond. The Power Plant Construction and Operation Agreement at Section 13.1 states: "Except as otherwise provided herein, the City shall have full ownership, management, operation and control over its Station Two." The 1993 Amendments define Station Two to include the generating facility and "to the extent furnished and owned by City …all auxiliary facilities, joint use facilities and related facilities…" As listed in Exhibit 1, Page 1 of 3 Part B item 13 to the 1993 Amendments, the Station

Two ash pond is a Joint Use Facility Provided By and Owned By the City But Located on Big Rivers' Property. Section 4.1 of the Joint Facilities Agreement states that "[T]itle to those joint use facilities or portions thereof provided by City will remain in City."

Paragraph 8 of the 1993 Amendments requires Big Rivers to share in the decommissioning costs of Station Two. If the City elects to decommission its power plant, then Big Rivers will pay its share. Decommissioning requires demolition and Big Rivers cannot demolish the City's property without its permission. But Big Rivers has no contractual obligation to share in any Station Two (including the Station two ash pond) retirement-in-place costs. As the sole owner of Station Two (including all Joint Use Facilities furnished and owned by the City), all retirement in place costs are Henderson's responsibility. Please also refer to Mr. Pullen's April 28, 2020, letter to Mr. Heimgartner for a more detailed explanation as to why Henderson is the owner and operator of the Station Two ash pond and is therefore responsible for all current and future compliance obligations under the CCR Rule. That April 28, 2020, letter is an attachment to Big Rivers' response to Item 2 of Henderson's Supplemental Request for Information.

a. Please see the response above.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 4) ***Refer to Big Rivers' Response to Item No. 74 of Henderson's First Request for Information. Is it Big Rivers' position that charges purportedly associated with the closure and/or decommissioning of Station Two should not be subject to Henderson approval?***

Response) No. Big Rivers' position is that the City is the owner of Station Two, therefore, the closure and decommissioning of Station Two is subject to the City's purchasing guidelines and approval process.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

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Item 5) ***Please state whether Big Rivers will propose a process whereby the Commission would determine that charges filed on a monthly basis by Big Rivers and purportedly owed by Henderson are reasonable, necessary, and reasonably related to Station Two. If so, please describe the proposed process.***

Response) Please see my Direct Testimony, page 17.

Witness) Paul G. Smith

BIG RIVERS ELECTRIC CORPORATION

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June 29, 2020

Item 6) ***Has Big Rivers notified either the Commission or any of Big Rivers' customers that Big Rivers intends to increase, decrease, or otherwise modify existing rates in the event its Application in this matter is denied? If so, please provide documentation of such notice. Additionally, provide any studies, calculations, or other information supporting the purported effect on rates resulting from a Commission decision in this case.***

Response) Please see Big Rivers' response to Item 6 of the Commission Staff's First Request for Information and Item 1 of Henderson's First Request for Information. Additionally, on June 25, 2020, the Commission issued an Order in Case No. 2020-00064 which ensures that the outcome in this proceeding will result in the modification (increase or decrease) of Big Rivers' rates.

Witness) Robert W. Berry

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
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Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 7) ***Has Big Rivers notified either the Commission or any of Big Rivers' customers that Big Rivers intends to increase, decrease, or otherwise modify existing rates in the event its Application in Case No. 2020-64 is denied? If so, please provide documentation of such notice. Additionally, provide any studies, calculations, or other information supporting the purported effect on rates resulting from a Commission decision in this case.***

Response) On June 25, 2020, the Commission issued an Order in Case No. 2020-00064 approving a New TIER Credit. Accordingly, the Commission's decision in this proceeding will impact Big Rivers' rates.

Witness) Robert W. Berry

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 8) ***Please describe the current status and condition of Big Rivers' Robert A. Reid Station ("Reid"). Your response should include answers to the following inquiries:***

a. When was Reid removed from service?

b. Identify and describe all activities Big Rivers has performed at Reid since the plant was last operated.

c. Has Reid been placed in "safe, dark, and dry" condition? If so, when did this occur?

d. Has Big Rivers received any proposals for decommissioning Reid? If so, please produce copies of those proposals.

e. Provide details of any and all plans, schedules, and proposed costs to decommission Reid.

f. Please state the current number of personnel assigned to Reid and the number of man hours and associated cost of maintaining Reid in its current condition.

g. Identify all asbestos removal activities performed at Reid since the plant last operated.

h. ***If asbestos has not been removed from Reid, please explain the rationale underlying the decision to not remove asbestos.***

i. ***Has Big Rivers received any proposals for asbestos removal at Reid? If so, produce copies of those proposals.***

j. ***Provide details concerning Big Rivers' plan and time frame for and the projected cost of removing asbestos from Reid.***

k. ***Identify all ponds or impoundments containing coal combustion residuals (CCRs) at Reid. Include in your answer a description of the pond or impoundment structure and state whether the pond or impoundment is lined or unlined, the size of the pond or impoundment, and the method and means by which each pond or impoundment is monitored.***

l. ***Have any of the CCR impoundments at Reid shown any indication of leakage or contamination of surrounding areas?***

m. ***What is the status of all ponds containing CCRs at Reid?***

n. ***Has Big Rivers received any proposals for closure of CCR ponds or impoundments at Reid? If so, produce copies of those proposals.***

o. Provide details concerning Big Rivers' plan and time frame for and the projected cost of closing CCR ponds and/or impoundments at Reid.

Response)

a. Reid Unit 1 was idled on April 1, 2016. It is not retired. Big Rivers anticipates retiring Reid Unit 1 in 2020 pending the outcome of PSC Case No. 2020-00064.[1] The Reid Combustion Turbine ("CT") remains in service and operating as required by the Midcontinent Independent System Operator, Inc. ("MISO").

b. Big Rivers has performed maintenance activities to facilitate maintaining Reid Unit 1 in the idled condition pending the final determination to either restart Reid Unit 1 or retire it permanently.

[1] See: *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs Through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief* – Case No. 2019-00435.

c. No. Reid 1 is idled but not retired. Big Rivers will not begin the decommissioning process until the unit is retired.

d. No.

e. Please see the Burns & McDonnell Decommissioning Cost Estimate Study, dated March 3, 2016, for the Coleman Station and Reid Unit 1 provided as a **CONFIDENTIAL** attachment to Big Rivers' response to Item 1b of Commission Staff's Initial Request for Information in this case.

f. There are no personnel assigned to Reid Unit 1 at this time. The annual maintenance expenses for the past four calendar years are:

Big Rivers Electric Corporation Reid Unit 1 Annual Maintenance Expense	
Year	**Amount**
2016	$ 121,062
2017	$ 201,568
2018	$ 240,045
2019	$ 217,440

g. Maintenance to the asbestos insulation system has been performed at Reid since 2016 while the unit continues to be idled.

h. Big Rivers has not begun the asbestos removal at this time because the unit is not retired.

i. No.

j. Big Rivers anticipates removing the asbestos from Reid Unit 1 upon its retirement which may occur in 2020 pending the outcome of the PSC Case No. 2020-00064.

k. There are no ponds or impoundments at Reid. The Reid bottom ash was sluiced to the Station Two Ash Pond owned by the City of Henderson. The bottom ash from the Station Two ash pond was dredged from the pond and placed into the Green landfill.

l. Not applicable.

m. Not applicable.

n. Not applicable.

o. Not applicable.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
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Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

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Item 9) ***Please describe the current status and condition of Big Rivers' Kenneth C. Coleman Station ("Coleman"). Your response should include answers to the following inquiries:***

a. When was Coleman removed from service?

b. Identify and describe all activities Big Rivers has performed at Coleman since the plant was last operated.

c. Has Coleman been placed in "safe, dark, and dry" condition? If so, when did this occur?

d. Has Big Rivers received any proposals for decommissioning Coleman? If so, please produce copies of those proposals.

e. Provide details of any and all plans, schedules, and proposed costs to decommission Coleman.

f. Please state the current number of personnel assigned to Coleman and the number of man hours and associated cost of maintaining Coleman in its current condition.

g. Identify all asbestos removal activities performed at Coleman since the plant last operated.

h. If asbestos has not been removed from Coleman, please explain the rationale underlying the decision to not remove asbestos.

i. Has Big Rivers received any proposals for asbestos removal at Coleman? If so, produce copies of those proposals.

j. Provide details concerning Big Rivers' plan and time frame for and the projected cost of removing asbestos from Coleman.

k. Identify all ponds or impoundments containing coal combustion residuals (CCRs) at Coleman. Include in your answer a description of the pond or impoundment structure and state whether the pond or impoundment is lined or unlined, the size of the pond or impoundment, and the method and means by which each pond or impoundment is monitored.

l. Have any of the CCR impoundments at Coleman shown any indication of leakage or contamination of surrounding areas?

m. ***What is the status of all ponds containing CCRs at Coleman.***

n. ***Has Big Rivers received any proposals for closure of CCR ponds or impoundments at Coleman? If so, produce copies of those proposals.***

o. ***Provide details concerning Big Rivers' plan and time frame for and the projected cost of closing CCR ponds and/or impoundments at Coleman.***

Response)

a. The Coleman Station was idled in May 2014. It is not retired. Big Rivers anticipates retiring the Coleman Station in 2020 pending the outcome of PSC Case No. 2020-00064.[1]

b. Big Rivers has performed maintenance activities to facilitate maintaining the Coleman Station in the idled condition pending the final determination to either restart Coleman or retire it permanently.

[1] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Modify its MRSM Tariff, Cease Deferring Depreciation Expenses, Establish Regulatory Assets, Amortize Regulatory Assets, and Other Appropriate Relief* – Case No. 2020-00064.

c. No. Coleman is idled but not retired. Big Rivers will not begin the decommissioning process until the unit is retired.

d. Yes. Please see the **CONFIDENTIAL** proposal from Commercial Development Company provided as Attachment 1 to this response, and the **CONFIDENTIAL** proposal from NorthStar provided as Attachment 2 to this response.

e. Please see the Decommissioning Cost Estimate Study, dated March 3, 2016, for the Coleman Station and Reid Unit 1 provided as a **CONFIDENTIAL** attachment to Big Rivers' response to Item 1b of Commission Staff's Initial Request for Information in this case.

f. Big Rivers has a one security guard assigned to the plant on a 24/7 basis. The annual maintenance expenses for the past five calendar years are shown in the table on the following page:

Big Rivers Electric Corporation Coleman Station Annual Maintenance Expense			
Year	**Labor (a)**	**Non-Labor (b)**	**Total (c) = (a) + (b)**
2015	$ 603,153	$ 552,419	$ 1,155,572
2016	$ 493,996	$ 478,000	$ 971,996
2017	$ 543,651	$ 343,708	$ 887,359
2018	$ 543,913	$ 292,884	$ 836,797
2019	$ 413,077	$ 344,133	$ 757,210

g. Maintenance to the asbestos insulation system has been performed at Coleman since 2014 while the unit continues to be idled.

h. Big Rivers has not begun the asbestos removal at this time because the unit is not retired.

i. No.

j. Big Rivers anticipates removing the asbestos from Coleman upon its retirement which may occur in 2020 pending the outcome of the PSC Case No. 2020-00064.

k. The existing ash ponds at the Coleman Station are designated as the South Pond, Sluice Pond, and North Pond. They liners are clay-lined. The

Coleman ponds are legacy ponds as defined by the Coal Combustion Residual ("CCR") Rule. The North Pond is approximately sixty (60) acres in size with an overflow pond located off of the north perimeter berm. The Sluice Pond covers approximately forty-nine (49) acres of the Coleman Station and was primarily utilized as the sluice discharge location for bottom ash and fly ash. The main portion of the South Pond is approximately ninety-four (94) acres in size and located to the south and west of the main powerblock area; an additional area, which has been beneficially used for parking, laydown, and by-product stack out, consists of approximately thirteen (13) acres located north/across of the main Station entrance road from the South Pond main area.

Because the Coleman Station's units have not operated (and its ash ponds have not received CCR) since before the CCR Rule became effective, the closure of the relevant ash ponds has historically been outside of regulatory constraints. However, on August 21, 2018, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded a number of provisions within the CCR Rule, including those that exempt legacy ponds from regulation.

l. No.

m. It is expected that Coleman's legacy ash ponds will be subject to the CCR Rule in substantially the same manner as other ash ponds; therefore, it has been assumed that the three ponds will be capped in place with the cover system as outlined in the CCR Rule. The CCR Rule's prescribed cover system, for unlined impoundments, consists of eighteen (18) inches of clay infiltration layer, and six (6) inches of topsoil that is capable of sustaining vegetation.

n. No.

o. From start to finish, the closure of the Coleman Station ash ponds is expected to take approximately five (5) years. This schedule includes roughly five (5) months for detailed engineering design and three (3) months for a bid process. The overall construction schedule, which was developed based on 8-hour, 5-day work weeks, reflects the volume of the

CCR material to be graded and consolidated on-site. The estimated daily grading production rate of moving wet CCR material within the ponds is 3,500 cubic yards, assuming the use of two (2) excavators and eight (8) haul trucks. Installation of the infiltration layer will be limited or will cease during the winter months because of the potential for freeze-thaw cracking and desiccation of the cohesive system.

Witness) Michael T. Pullen

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
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Item 10) ***Please disclose the percentage of waste material, including but not limited to fly ash, bottom ash, scrubber sludge, construction debris, trash, and hazardous waste deposited in the Green Landfill from each of the following sources: i) Reid plant; ii) Green plant; iii) Station Two plant; iv) Coleman plant; v) other sources.***

a. ***If you contend that one or more of the listed sources is not a source of material deposited in the Green Landfill, please identify the source(s).***

b. ***With respect to "other sources," please identify the source and the nature of the material deposited into the landfill and attributable to that source.***

c. ***Please provide a list of contractors or other parties who hauled any type of waste from any source to the Green Landfill.***

d. ***Please produce copies of any and all contracts between Big Rivers and any other party who hauled any type of waste from any source to the Green Landfill.***

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Response) Please see the attachment to Big Rivers' response to Item 63 of Henderson's First Request for Information for the calculations used in this response.

Big Rivers Electric Corporation
Percentage of Waste Material Deposited in Green Landfill

Source	Percentage
Reid Station	0.00%
Green Station	62.88%
Station two	37.12%
Coleman Station	0.00%
Other Sources	0.00%

a. The sources are Green Station and Station Two poz-o-tec, also known as scrubber sludge. As explained in Big Rivers' response to Item 62 of Henderson's First Request for Information, the exact quantity of bottom ash from Reid Station and Station Two disposed in the Green Landfill is unknown at this time because there remains a residual amount of bottom ash in the Station Two ash pond today. Likewise, there is an unknown quantity of Green Station bottom ash that has been disposed in the Green Landfill. Big Rivers believes that a reasonable estimate of the bottom ash from these three sources could be calculated by the parties.

b. There is no waste from "other sources" in the Green Landfill.

c. Charah Inc. hauled waste to the Green Landfill.

d. See Big Rivers' response to Item 58 of Henderson's First Request for Information.

Witness) Michael T. Pullen

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 11) ***Please state whether ash attributable to Station Two was hauled to or deposited anywhere other than in the Green Landfill. If so, please state:***

a. ***The amount of Station Two ash hauled to a different site or deposited somewhere other than in the Green Landfill;***

b. ***The name of the site to which the ash was hauled and/or the facility into which the ash was deposited.***

c. ***The time frame during which the ash was hauled to or deposited somewhere other than in the Green Landfill.***

d. ***The parties to any and all contracts under which the ash was hauled and/or deposited;***

e. ***The name of the Big Rivers supervisor who oversaw the hauling or depositing of Station Two ash to a different site or into a different facility.***

Response) In 2002, 2011, and 2012 poz-o-tec, also known as scrubber sludge, was used as beneficial reuse in areas other than the Green Landfill. This scrubber sludge is a combination of waste from both Green Station and Station Two.

a. 132,633 tons of scrubber sludge from Green Station and Station Two was hauled to sites other than the Green landfill.

b. The sites to which the scrubber sludge was hauled are Cochise mine and Sebree Mining.

c. The scrubber sludge was hauled to the other sites in the years 2002, 2011, and 2012.

d. The parties to the contract were Big Rivers and Charah Inc.

e. William Boarman oversaw the hauling of scrubber sludge to the other sites.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 12) ***Refer to Big Rivers' Response to Item No. 61 of Henderson's First Request for Information. Please identify the third party contractor referenced in your response.***

Response) The referenced third-party contractor is Charah Inc. based in Louisville, Kentucky.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 13) ***Will Big Rivers acknowledge that the energy at issue in the Henderson Circuit Court proceeding, Civil Action No. 09-CI-693, is that energy which was wanted by both parties to the Station Two contracts?***

Response) Henderson Circuit Court Civil Action No. 09-CI-693 concerned the parties' rights with respect to Excess Henderson Energy generally.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 14) ***Will Big Rivers acknowledge that the energy at issue in Commission Case No. 2016-278 is that energy which was unwanted by either party to the Station Two contracts?***

Response) The energy at issue in Case No. 2016-00278[1] was Excess Henderson Energy that Big Rivers elected not to take.

Witness) Robert W. Berry

[1] *See In the Matter of: In the Matter of: Application of Big Rivers Electric Corporation for a Declaratory Order* – Case No. 2016-00278.

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 15) ***Will Big Rivers acknowledge that its position at the time of the execution of the Settlement Agreement which resolved the Henderson Circuit Court action styled Big Rivers Electric Corp. v. City of Henderson, et al, Civil Action No. 09-CI-693, was that the unwanted energy at issue in Commission Case No. 2016-278 was not addressed in the Settlement Agreement?***

Response) No.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 16) ***Please provide a comprehensive list of those costs Big Rivers has avoided as a direct or indirect result of the closure of Station Two.***

Response) As a result of the closure of Station Two, Big Rivers and Henderson have avoided all costs required to generate electricity, including all variable costs such as fuel, fuel oil, and lime. Such avoided costs are offset by the retirement and decommissioning costs as described in the Application and supporting testimony.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 17) ***Will Big Rivers acknowledge that it was Big Rivers' position in Commission Case No. 2016-278 that energy not wanted by either party (unwanted Excess Henderson Energy) was the subject of that proceeding?***

Response) The energy that was the subject of Case No. 2016-00278 was Excess Henderson Energy that Big Rivers elected not to take.

Witness) Robert W. Berry

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 18) ***Will Big Rivers confirm that Henderson is not a Big Rivers ratepayer?***

Response) Yes.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 19) ***Will Big Rivers confirm that Big Rivers is not a Henderson ratepayer?***

Response) No. Big Rivers owns facilities in Henderson served by Henderson Municipal Power & Light, including its headquarters and ET&S facilities. In addition, Big Rivers purchased power from Henderson under the Station Two Contracts, including the Power Sales Contract.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 20) ***Refer to Big Rivers' Response to Item No. 4 of Henderson's First Request for Information and Big Rivers' Response to Item No. 6 of Commission Staff's Initial Request for Information.***

a. Will Big Rivers acknowledge that Big Rivers has not sought and is not seeking a rate adjustment as a result of Henderson's failure to pay amounts allegedly owed to Big Rivers? If Big Rivers will not make the requested acknowledgement, please produce copies of any and all exhibits and/or schedules reflecting the requested rate adjustment.

Response)

a. Please see Big Rivers' response to Item 6 of the Commission Staff's First Request for Information and Item 1 of Henderson's First Request for Information.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 21) ***Refer to Big Rivers' Revised Response to Item 7 of the Commission Staff's Initial Request for Information, p. 4, line 11. Please cite to the specific language of the Commission's Order dated January 5, 2018, in which the Commission states that Henderson owns the excess energy unwanted by either party.***

Response) On pages 13-14 of its January 5, 2018, Order in Case No. 2016-00278, the Commission found:

> The Commission further finds that Big Rivers is not required to pay for any variable costs associated with Excess Henderson Energy that Big Rivers elects not to take. Section 3.8(d) of the 1998 amendments…clearly and unambiguously provides Big Rivers the discretion to purchase or not to purchase any Excess Henderson Energy. Because the Power Sales Contract requires each party to pay for the variable costs associated with the power taken or used by that party during any month, the Commission finds that Big Rivers is not obligated, under the express terms of the Power Sales Contract, as amended, to pay for any Excess Henderson Energy that is declined to be taken by Big Rivers at its discretion.

Further, in Ordering Paragraph No. 1 of that Order, the Commission held, "Big Rivers request for a declaration that, under the terms of the Power Sales Contract, as amended, it is not required to pay for any variable costs associated with Excess Henderson Energy that it declines to take is granted." As Big Rivers is not responsible for the variable costs of any Excess Henderson Energy that it declined to take, Henderson must be responsible for those costs.

Witness) Mark J. Eacret

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 22) ***Please explain the steps Big Rivers would have to have taken to withdraw Henderson assets from MISO registration upon receipt of written notice of Henderson's objection to MISO registration (Attachment B).***

a. What, if any, action did Big Rivers take in response to Henderson's written notice that Henderson did not want Big Rivers to register the Station Two units in MISO and intended to seek its own market participant?

b. Please produce a copy of any and all documents MISO sent to Big Rivers related to the registration of Station Two energy and capacity in MISO.

Response) Big Rivers and Henderson would have first required an economically viable alternative to MISO registration. Based upon NERC requirements, the process described in the Direct Testimony of Michael W. Chambliss, and the Kentucky Public Service Commission, there was none.

Please see MISO's Business Practices Manual for information on the Attachment B Change in Information process at: https://www.misoenergy.org/legal/business-practice-manuals/.

a. Big Rivers is unaware of any written notice from Henderson that Henderson did not want Big Rivers to register the Station Two units in MISO and intended to seek its own market participant. As Henderson was informed by Cheryl Bredenbeck, MISO's Director Transmission Services, and noted in Big Rivers' response to Item 45 of Henderson's First Request for Information, HMP&L was free to become its own market participant or to choose a different market participant at any time, subject to MISO deadlines and business practices. Ms. Bredenbeck's e-mails on this subject were provided as Attachment 1 and Attachment 2 to Big Rivers' response to Item 41 of Henderson's First Request for Information.

b. Please see Big Rivers' response to Item 26 of Henderson's Supplemental Request for Information.

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 23) ***Refer to Big Rivers' Response to Item 9(a) of the Commission Staff's Initial Request for Information and Big Rivers' Response to Item No. 23 of Henderson's First Request for Information. Please state the basis of your position that Big Rivers would not have been capable of fulfilling its offer to operate and maintain Station Two an additional 13 months (after termination of the Station Two contracts) without a severance package.***

a. State the amount of severance costs avoided as a result of Henderson's acquiescence to close Station Two 10 months after contract termination rather than 13 months after contract termination.

b. State whether Big Rivers has hired any bargaining or salaried employees since Station Two ceased operation on January 31, 2019. If so, please include in your answer the positions filled and explain why no severed employees were reassigned to those positions.

Response) Approximately 100 employees were employed at Station Two to perform the necessary work to operate and maintain the units, environmental equipment, fuel handling facilities, and balance-of-plant equipment. Big Rivers announced its plans to terminate the Station Two contract on May 1, 2018, and subsequently HMP&L announced its plan to retire Station Two. In order to maintain the safe and reliable operations of Station Two, Big Rivers decided it was necessary to offer a severance plan to ensure that a sufficient number of employees continued working until such time that the units were retired. In a May 21, 2018, letter from Chris Heimgartner, General Manager, HMP&L, to the Kentucky Public Service Commission ("PSC"), Mr. Heimgartner informed the PSC that "HMP&L agrees with Big Rivers' determination that a minimum of 13 months is necessary to conduct an orderly termination process." Mr. Heimgartner also stated that terminating the Station Two contracts "would result in the discontinuance of the operation of the Station Two generating plant Units One and Two requiring Henderson to secure an alternative power source for the residents of Henderson." That letter is provided in Attachment 1 to this response.

Furthermore, Mr. Heimgartner sent Big Rivers a letter on June 15, 2018, in which he provided HMPL's "acceptance of Big Rivers' May 1, 2018 offer to continue to operate and maintain Station Two for the sole benefit of Henderson, under the same terms and conditions as set forth in the Station Two contracts through May 31, 2019." That letter is Attachment 2 to this response. Mr. Heimgartner's two requests to the PSC and Big Rivers made it clear to Big Rivers that HMP&L expected Big Rivers to do what was necessary in order to continue the operation of the units until such time that Henderson could secure an alternative power source for its residents which included maintaining a workforce to operate and maintain the Station Two generating units.

It is a prudent and common practice for utilities to offer severance programs in order to entice employees to remain employed at a facility that is scheduled for retirement in order to maintain the safe and reliable operation of generating units. In fact, Owensboro Municipal Utilities ("OMU") offered a retention program to its employees when faced with a similar situation with its Elmer Smith units. Please see Attachment 3 to this response for an *Owensboro Messenger-Inquirer* article detailing OMU's efforts.

a. There was no severance plan savings due to the retirement of Station Two prior to the thirteen month original retirement date. Big Rivers paid six-months severance pay to all employees whose employment was terminated as a result of the Station Two retirement. Henderson's agreement to close the plant three months earlier did not reduce the number of employees whose positions were eliminated as a result of the station retirement.

b. Big Rivers objects to this request for information. Big Rivers' employment decisions since the retirement of Station Two are irrelevant to the issues in this case. Notwithstanding that objection, all employees who were severed from Big Rivers as a result of the retirement of Station Two were required to sign a severance agreement which, among other releases, waived any rights to recall by Big Rivers.

Witness) Robert W. Berry

HMP&L Henderson Municipal Power & Light

May 22, 2018

Mr. Robert W. Berry
President and CEO
Big Rivers Electric Corporation
201 3rd Street
Henderson, KY 42420

MAY 2 2 2018

Re: PSC Case No. 2018-00146

Dear Bob,

We have replied to your filing in the referenced case. Attached for your information and use is that reply.

Please feel free to contact me directly if you have any questions.

Sincerely,

Chris Heimgartner
General Manager, Henderson Municipal Power and Light

cc: Mayor Steve Austin
Utility Commission Chairman, Gary Bell
Randall Redding

Enclosure

Case No. 2019-00269
Attachment 1 for Response to HMPL 2-23
Witness: Robert W. Berry

100 FIFTH STREET P.O. BOX 8 HENDERSON, KENTUCKY 42419-0008 (270) 826-2726 FAX (270)826-9650

Steve Austin, Mayor

Commissioners:
Patti Bugg
Robert N. Pruitt Sr.
Bradley S. Staton
Austin P. Vowels

The City of Henderson

P.O. Box 716
Henderson, Kentucky 42419-0716

HENDERSON
John J. Audubon's
KENTUCKY HOME

Russell R. Sights, City Manager
Dawn S. Kelsey, City Attorney
Maree Collins, City Clerk
Donna Stinnett, Public Information Officer/Community Relations Manager

May 21, 2018

Ms. Gwen R. Pinson
Executive Director
Public Service Commission
211 Sower Boulevard
Post Office Box 615
Frankfort, KY 40602-0615

RE: In The Matter of: Notice of Termination of Contracts and Application of Big Rivers Electric Corporation for a Declaratory Order and For Authority to Establish A Regulatory Asset
Case No. 2018-00146

Dear Ms. Pinson:

The City of Henderson, Kentucky and Henderson Municipal Power & Light are writing to comment on the application by Big Rivers Electric Corporation to terminate the Station Two contracts.

The City of Henderson, Kentucky, through the Henderson Utility Commission ("Henderson"), provides electricity to 11,954 customers.

This power supply has been provided to the HMP&L customer base since 1972 through the generation of the electric generating plant referred to as Station Two in the Notice of Termination Application of Big Rivers Electric Corporation, Case No. 2018-00146.

The request by Big Rivers to terminate the Station Two contracts would result in the discontinuance of the operation of the Station Two generating plant Units One and Two requiring Henderson to secure an alternative power source for the residents of Henderson.

KENTUCKY
Henderson
Discover your nature.

"HMP&L" agrees with Big Rivers' determination that a minimum of 13 months is necessary to conduct an orderly termination process.

This action is not acquiescing to or agreeing to any testimony, allegations, assertions, studies or other claims contained in the pleadings filed by Big Rivers, including the jurisdiction of the Public Service Commission over this matter.

Henderson reserves its right to intervene and contest any request or supplemental filing by Big Rivers requesting different or additional relief outside of the present filing.

Further, Henderson retains its right to assert any and all legal rights in this or any other proceeding, including the termination of the affected contracts.

Sincerely,

By:______________________________

Steve Austin, Mayor
City of Henderson, Kentucky

By:______________________________

Chris Heimgartner, General Manager
Henderson Municipal Power & Light

HMP&L
Henderson Municipal Power & Light

June 15, 2018

Bob Berry
President & CEO
Big Rivers Electric Corp.
201 Third Street
Henderson, KY 42420

Dear Bob,

Please allow this letter to serve as acceptance of Big Rivers' May 1, 2018 offer to continue to operate and maintain Station Two under the same terms and conditions as set forth in the Station Two contracts through May 31, 2019.

Sincerely,

Chris Heimgartner
General Manager
Henderson Municipal Power & Light

Case No. 2019-00269
Attachment 2 for Resposne to HMPL 2-23
Witness: Robert W. Berry
Page 1 of 1

100 FIFTH STREET P.O. BOX 8 HENDERSON, KENTUCKY 42419-0008 (270) 826-2726 FAX (270)826-9650

Messenger-Inquirer.com

OMU OKs raise for power production staff employees

Author(s): Austin Ramsey
Messenger-Inquirer **Date:** November 17, 2017 **Section:** news/local

Owensboro Municipal Utilities on Thursday approved the first part of a comprehensive retention program aimed at keeping its 74 power production employees at the **Elmer** Smith Station coal-fired plant, which is scheduled to shut down completely by 2023. The Owensboro Utility Commission approved a 10 percent base salary increase for all but four employees with more than 20 years of experience, who will each earn increases of 6 percent. All of the pay hikes are scheduled to go into effect early next month.

Officials stressed the importance of retaining qualified, experienced personnel who can safely and effectively operate the waning plant until its very last day. Michael Moore, director of customer service and shared services, said it's not lost on the public utility what asking many of these employees to stay means. Retiring the plant, the first step of which will take place in 2019 when the smaller boiler -- Unit 1 -- shutters, means power production positions will be eliminated. Those employees know that better than anyone, he said, and they are naturally looking for other long-term jobs or considering retirement.

Already, he said, some the workforce has been depleted since the plant retirement plan was announced earlier this year.

"But in order to keep (the Smith station) running, **OMU** will need a workforce that is knowledgeable and competent," he said. "Our current employees are the best at what they do. Retaining them is important to achieving part of our mission, which is providing electrical power at the most economical costs."

Tony Cecil, who sits on the Utility Commission, stressed the importance of Thursday's vote, not only for employees, but for the ratepayers as well.

"This decision, while it impacts the employees, wasn't done entirely for them," he said. "We have to keep that plant going until the shutdown, and if it means paying more money to do it, to keep the ratepayer costs down, that's what it takes."

With benefits, the total pay increase for all 74 employees amounts to about a 4.56 percent increase and adds $406,000 to the utility's 2017-18 budget. It's likely, officials said, that it would have no fiscal year impact, because at least three positions that were budgeted for the year are unfilled because of retirements and resignations and they will not be backfilled going forward. That, combined with overbudgeted salaries would offset any budget constraints. Unforeseen overtime costs could change that quickly, however, and a slight budget amendment has been recommended.

OMU officials have said previously that the retention program will include pay incentives to Smith plant employees who agree to continue working at the plant until their coal-fired expertise is no longer needed. Over the entire six-year duration of the program, including benefits, the cost will run to more than $9 million.

Total payroll for the 74 power production employees is $8.9 million this year.

Austin Ramsey, 270-691-7302, aramsey@messenger-inquirer.com, Twitter: @austinrramsey

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 24) ***Refer to Direct Testimony of Robert W. Berry, p. 48, line 17, through p. 49, line 3. Please state the methodology used to calculate purported savings to Henderson of $3.1 million in 2015.***

Response) Please see Big Rivers' response to Item 6 of Commission Staff's Second Request for Information.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 25) ***Refer to Section 6.1 of the Joint Facilities Agreement, as amended. Refer to Direct Testimony of Michael T. Pullen, p. 17, lines 13-14. Will Big Rivers acknowledge that the Station Two ash-pond dredgings no longer serve a continuously operating generating station?***

Response) The Station Two ash-pond dredgings are a Joint Use Facility provided by and solely owned by the City but located in Big Rivers' Green landfill. The Green landfill serves the Green Station which is a continuously operating generating station. Under Section 6.1 of the Joint Facilities Agreement and Paragraph 8 of the 1993 Amendments, once the Green landfill is itself decommissioned Henderson will be responsible for 100% of the Station Two ash pond dredgings if Station Two is retired-in-place, but only 22.76% if Station Two is decommissioned. Before the Green landfill is decommissioned, Henderson is responsible for a usage based allocation of ongoing Green landfill costs based upon Section 7 of the Joint Facilities Agreement as amended by the 1993 Amendments.

Witness) Michael T. Pullen

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 26) ***Please produce copies of all correspondence between Big Rivers and MISO regarding the registration of Station two load and capacity in MISO.***

Response) Big Rivers objects to this request as being overly broad and unduly burdensome. Without waiving that objection, Big Rivers states as follows:

Please see the attached October 19, 2010, letter between Mark Bailey, Big Rivers' former President and Chief Executive Officer, and Gary Quick, HMP&L's General Manager at the time. Also, please see the e-mail exchanges between Mr. Quick and Cheryl Bredenbeck, MISO's Director Transmission Services, provided as Attachment 1 and Attachment 2 to Big Rivers' response to Item 41 of Henderson's First Request for Information.

Witnesses) Michael W. Chambliss and
Mark J. Eacret

ul Yockey

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

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FILE COPY

210.20.53.8

October 19, 2010

Mr. Gary Quick
Henderson Municipal Power & Light
P. O. Box 8
Henderson, KY 42419-0008

Dear Gary:

This letter responds to your letter to me of September 30, 2010. In order to complete the integration of Big Rivers into the Midwest ISO by the end of the year, Midwest ISO required registration of the Station Two asset and the City of Henderson load in September. Our understanding from Midwest ISO was that HMP&L was fully cognizant of the Midwest ISO registration process requirements and timeline, and that HMP&L was agreeable with Big Rivers taking this action pending HMP&L deciding what it wanted to do with respect to Midwest ISO.

We have not been party to your meetings with Midwest ISO or The Energy Authority ("TEA"). As of September 15, we did not know the status or content of those discussions. As of September 15, the last information I had from you was your e-mail message of July 6, in which you said you were studying the data presented in your external study, would make a decision in a short time and would let me know the decision. You have still not informed Big Rivers that HMP&L has reached a decision about its plans with respect to Midwest ISO. Even in your letter of September 30 you say only that "Henderson *has considered* becoming a Market Participant or retaining a third party to act as [your] Market Participant," and that "Henderson has also *indicated an interest* in registering Station Two with MISO." Given our understanding from Midwest ISO that any change in registration of Station Two by HMP&L or TEA must involve discussions with Big Rivers as plant operator, we must assume that HMP&L still has not moved forward with an alternate plan.

Please understand that, in any event, Big Rivers had no choice but to move forward with registration of the Station Two asset and the City of Henderson load with Midwest ISO. Big Rivers has a legal obligation as Balancing Authority and under the Station Two contracts to comply with applicable laws, including the NERC Contingency Reserve requirement. Failure to comply with those laws can result in millions of dollars of penalties. As you must know from your monitoring of the Public Service Commission's consideration of Big Rivers' application to join Midwest ISO, even the aluminum smelters and other large industrial users who purchase Big Rivers power and will shoulder a majority of the costs of Midwest ISO membership agree that Midwest ISO membership by Big Rivers is the only reasonable alternative available to satisfy the NERC Contingency Reserve requirement.

Big Rivers' application to join Midwest ISO gave it temporary access to the Midwest ISO Attachment RR reserve service, but service under Attachment RR expires December 31, 2010. For Big Rivers to complete its integration into Midwest ISO by the end of this year and have access to the Midwest ISO tariff by which the Contingency Reserve requirement can be met, all generating assets and load in its Balancing Authority Area had to be registered with Midwest ISO in September.

Please let us know when you would like to discuss these subjects further.

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information
dated June 18, 2020

June 29, 2020

Item 27) ***Refer to Big Rivers' Response to Item No. 49 of Henderson's First Request for Information.***

a. Define the term "economically feasible" as used in your response.

b. Provide the specific "NERC Contingency Reserve requirements" referenced in your response.

c. State whether Big Rivers performed or authorized the performance of any studies or analyses regarding Henderson's ability to meet NERC Contingency Reserve requirements.

Response)

a. Economically feasible alternative means an alternative that is not cost prohibitive.

b. The NERC Contingency Reserve requirement referenced is BAL-002. A copy of BAL-002 was provided as Exhibit 16 to Big Rivers' Application in this case.

c. Big Rivers hired Charles River Associates ("CRA") to perform an economic assessment of Big Rivers' contingency reserve options. Big Rivers did not perform or authorize a study specific to Henderson's ability to meet NERC Contingency Reserve requirements. Section 2.1 of the System Reserves Agreement says that "The City and Big Rivers covenant and agree that each will comply with any system reserve capacity requirements now required or imposed at a future date applicable to it (as such requirements may be modified from time to time and as such requirements apply to it given its respective operational characteristics) by NERC, ECAR, any successor organizations to NERC and ECAR (as applicable), any applicable regulatory or governmental agency, and any regional transmission authority, reliability council or like organization, in each case having any system reserve capacity requirements applicable to it. Absent such a requirement, neither City nor Big Rivers shall have any obligation pursuant to this Agreement to maintain system reserves. Notwithstanding the above limitations, City agrees to comply with any requirements validly imposed by any of the above entities upon Big Rivers based on Big Rivers' role as control area operator, but only if and to the extent that such requirements imposed on Big Rivers are on account of or due to the generation and/or load of the City."

In addition, Section 30 (COMPLIANCE WITH GOVERNMENTAL REGULATIONS) of the Power Plant Construction and Operation Agreement provides that "City and Big Rivers will, at all times, faithfully obey and comply with existing and future laws, rules and regulations of federal, state or local governmental bodies lawfully affecting the operations and activities of and in connection with City's Station Two."

Since Henderson took no action to meet its contingency reserve requirement, Big Rivers was forced to take action on behalf of Henderson. As such, the CRA results were in effect applicable to Henderson as well as Big Rivers.

Witness) Michael W. Chambliss

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
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FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 28) ***Please produce copies of any correspondence, including enclosures and attachments, sent from Big Rivers to MISO on July 29, 2010, and related to any Grandfathered Agreement.***

Response) Big Rivers objects to this request on the grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving its objections to this request, Big Rivers responds as follows:

Please see Attachment 1 to this response for Big Rivers' July 29, 2010, letter to MISO. Please see Attachment 2 to this response for the Grandfather Agreement registrations.

Witness) Mark J. Eacret

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

July 29, 2010

Ms. Andrea Pewarski
Midwest ISO FTR Market Administration
701 City Center Drive
Carmel, IN 46032

RE: Grandfathered Agreement (GFA) Filing Templates

Dear Ms. Pewarski:

Please find enclosed the Grandfathered Agreement (GFA) Filing Templates as completed and executed by Big Rivers Electric Corporation. The only difference in today's filings, as opposed to the GFA's previously emailed to MISO, is the HMP&L contract termination (relative to Contract 510) was extended by later agreements.

If you have any questions regarding these GFA's and information provided, please feel free to contact us.

Sincerely,

C. William Blackburn vk

C. William Blackburn
Senior VP Financial and Energy Services and CFO

CWB/vk

Enclosures

Cc: Bill Yeary

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

- (•) Yes
- ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 510

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

- ( ) Yes
- ( ) No
- (•) Undecided

8. Is this a firm contract?

Please Choose one

- (•) Yes
- ( ) No
- ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

To the end of the economic life of the generating units.

15. Parties Filing Jointly? (Only applicable to joint filings)

City of Henderson, Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW

9. Source*	10. Sink*	11. Maximum MW permissible under the GFA Agreement*	12. TSR #	13. OASIS Page
BREC.HMP1.HMPL	BREC.HMPL	105 total between both	-	-
BREC.HMP2.HMPL	BREC.HMPL	105 total between both	-	-

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2009 - 5/31/2010

Definitions
Winter: December, January, February
Spring: March, April, May
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Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW

Source	Sink	Total Scheduled MWh(s)	Total Hours Scheduled	Season	Time of Use (Peak or Off-Peak)
BREC.HMP1.HMPL	BREC.HMPL	91,893	1122	Summer	Peak
BREC.HMP1.HMPL	BREC.HMPL	72,110	1085	Summer	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	74,681	1071	Fall	Peak
BREC.HMP1.HMPL	BREC.HMPL	65,849	1114	Fall	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	83,697	1054	Winter	Peak
BREC.HMP1.HMPL	BREC.HMPL	77,549	1106	Winter	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	79,067	1095	Spring	Peak
BREC.HMP1.HMPL	BREC.HMPL	62,601	1028	Spring	Off-Peak
Note: The source above is listed as BREC.HMPL1.HMPL however part of the source was also BREC.HMPL2.HMPL					

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes: (i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 511

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

Evergreen until 3 years notice.
No earlier than 2017

15. Parties Filing Jointly? (Only applicable to joint filings)

City of Henderson, Big River Electric Corp.
Southeastern Power Administration (SEPA)

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	10. Sink*	11. Maximum MW permissible under the GFA Agreement*	12. TSR #	13. OASIS Page
TVA	BREC.HMPL	12	-	-

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-28
Witness: Mark J. Eacret

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2009 - 5/31/2010

Definitions
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Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW

Source	Sink	Total Scheduled MWh(s)	Total Hours Scheduled	Season	Time of Use (Peak or Off-Peak)
TVA	BREC.HMPL	2315	1056	Summer	Peak
TVA	BREC.HMPL	1973	1151	Summer	Off-Peak
TVA	BREC.HMPL	2729	1008	Fall	Peak
TVA	BREC.HMPL	2759	1177	Fall	Off-Peak
TVA	BREC.HMPL	4665	992	Winter	Peak
TVA	BREC.HMPL	5285	1168	Winter	Off-Peak
TVA	BREC.HMPL	3580	1010	Spring	Peak
TVA	BREC.HMPL	3462	1084	Spring	Off-Peak

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 512

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

Five Years notice

15. Parties Filing Jointly? (Only applicable to joint filings)

Southeastern Power Administration (SEPA),
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
TVA	BREC.BREC	178	-	-

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-28
Witness: Mark J. Eacret

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
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Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**
TVA	BREC.BREC	35,295	1122	Summer	Peak
TVA	BREC.BREC	28,590	1085	Summer	Off-Peak
TVA	BREC.BREC	42,207	1071	Fall	Peak
TVA	BREC.BREC	39,647	1114	Fall	Off-Peak
TVA	BREC.BREC	72,895	1054	Winter	Peak
TVA	BREC.BREC	75,311	1106	Winter	Off-Peak
TVA	BREC.BREC	56,358	1081	Spring	Peak
TVA	BREC.BREC	49,483	1025	Spring	Off-Peak

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
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1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 513

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

24 months notice of termination

15. Parties Filing Jointly? (Only applicable to joint filings)

Louisville Gas and Electric Company,
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
LGEE	BREC	As necessary - varies	-	-

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-28
Witness: Mark J. Eacret

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2009 - 5/31/2010

Definitions
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Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW

Source	Sink	Total Scheduled MWh(s)	Total Hours Scheduled	Season	Time of Use (Peak or Off-Peak)
LGEE	BREC	0	0	Summer	Peak
LGEE	BREC	0	0	Summer	Off-Peak
LGEE	BREC	0	0	Fall	Peak
LGEE	BREC	0	0	Fall	Off-Peak
LGEE	BREC	0	0	Winter	Peak
LGEE	BREC	0	0	Winter	Off-Peak
LGEE	BREC	0	0	Spring	Peak
LGEE	BREC	0	0	Spring	Off-Peak

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

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1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 514

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

After 12/21/2003, will continue in 23 month increments
unless terminated

15. Parties Filing Jointly? (Only applicable to joint filings)

Associated Electric Cooperative, Inc.,
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
AECI	BREC	As necessary	-	-

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
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Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**
AECI	BREC	0	0	Summer	Peak
AECI	BREC	0	0	Summer	Off-Peak
AECI	BREC	0	0	Fall	Peak
AECI	BREC	0	0	Fall	Off-Peak
AECI	BREC	0	0	Winter	Peak
AECI	BREC	0	0	Winter	Off-Peak
AECI	BREC	0	0	Spring	Peak
AECI	BREC	0	0	Spring	Off-Peak

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose

The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions

Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff

Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 515

4. GFA Option Type: Option A

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

1/1/2043

15. Parties Filing Jointly? (Only applicable to joint filings)

Jackson Purchase Rural Electric Cooperative Corporation,
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
BREC	BREC.BREC	151	-	-

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2008 - 5/31/2009

Definitions
Winter: December, January, February
Spring: March, April, May
Summer: June, July, August
Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one
(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 516

4. GFA Option Type: Option A

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one
( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one
(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

1/1/2043

15. Parties Filing Jointly? (Only applicable to joint filings)

Meade County Rural Electric Cooperative Corporation,
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	10. Sink*	11. Maximum MW permissible under the GFA Agreement*	12. TSR #	13. OASIS Page
BREC	BREC.BREC	133	-	-

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****
Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2008 - 5/31/2009

Definitions
Winter: December, January, February
Spring: March, April, May
Summer: June, July, August
Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one
(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 517

4. GFA Option Type: Option A

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one
( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one
(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

1/1/2043

15. Parties Filing Jointly? (Only applicable to joint filings)

Green River Electric Corporation,
Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
BREC	BREC.BREC	367	-	-

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-28
Witness: Mark J. Eacret

Carve Out Historical Usage
FOR CARVE OUT GFA(S) ONLY

Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2008 - 5/31/2009

Definitions
Winter: December, January, February
Spring: March, April, May
Summer: June, July, August
Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	Sink	Total Scheduled MWh(s)	Total Hours Scheduled	Season	Time of Use (Peak or Off-Peak)

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose
The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions
Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff
Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

◉ Yes ○ No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 518

4. GFA Option Type: Option A

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

○ Yes ○ No ◉ Undecided

8. Is this a firm contract?

Please Choose one

◉ Yes ○ No ○ Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

1/1/2043

15. Parties Filing Jointly? (Only applicable to joint filings)

Henderson-Union, Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
BREC	BREC.BREC	367	-	-

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-28
Witness: Mark J. Eacret

Carve Out Historical Usage
*****FOR CARVE OUT GFA(S) ONLY*****

Section 2

Purpose
This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions
1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab
3. For each path (Source/Sink pair), please enter the Total Scheduled MWh(s) and the Total Hours Scheduled within a particular Season and Time of Use (Peak or Off-Peak)
4. If possible please provide data from 6/1/2008 - 5/31/2009

Definitions
Winter: December, January, February
Spring: March, April, May
Summer: June, July, August
Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 29) ***Please provide the number of the Grandfathered Agreement associated with the Power Sales Contract between Henderson and Big Rivers.***

Response) Grandfathered Agreement 510 was associated with the transmission of power from Station Two to Henderson load.

Witness) Mark J. Eacret

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 30) ***Please produce copies of all MISO Grandfathered Agreement filing templates as completed and executed by Big Rivers in 2010.***

Response) Please see the attachment to this response and Big Rivers' response to Item 28 of Henderson's Supplemental Request for Information.

Witness) Mark J. Eacret

Grandfathered Agreement (GFA) Filing Template

Section 1

Purpose

The objective is to determine what rights and obligations the Midwest ISO will assign to market participants on behalf of the GFAs.

Definitions

Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under the Tariff

Grandfathered Agreement (GFA) Scheduling Entity: An entity responsible for scheduling transmission service or energy transactions related to Grandfathered Agreements under the Tariff

1. Is this a joint filing? (If yes, please list all parties in 15.)

Please Choose one

(●) Yes ( ) No

2. Filing Party: Big Rivers Electric Corp.

3. Contract Number: 510

4. GFA Option Type: Carve Out

5. Responsible Entity*: Big Rivers Electric Corp.

6. Scheduling Entity*: Big Rivers Electric Corp.

7. Does this contract fall under the Mobile Sierra Standard of Review?

Please Choose one

( ) Yes ( ) No (●) Undecided

8. Is this a firm contract?

Please Choose one

(●) Yes ( ) No ( ) Undecided

9-13. (Please go to the table to the right)

14. GFA Termination Date

30 years after commencement, otherwise when all Station
Two bonds of the City of Henderson which have been
approved by Big Rivers have been paid

15. Parties Filing Jointly? (Only applicable to joint filings)

City of Henderson, Big River Electric Corp.

* Information is required to be submitted under Section 38.2.5.j of the Tariff

Source, Sink & MW				
9. Source*	**10. Sink***	**11. Maximum MW permissible under the GFA Agreement***	**12. TSR #**	**13. OASIS Page**
BREC.HMP1.HMPL	BREC.HMPL	105 total between both	-	-
BREC.HMP2.HMPL	BREC.HMPL	105 total between both	-	-

Carve Out Historical Usage

FOR CARVE OUT GFA(S) ONLY

Section 2

Purpose

This objective is to obtain the Carve Out GFA's historical usage to establish a set of assumptions for FTR modeling.

Directions

1. This section is applicable for Carve-Outs only. This section does not need to be completed for Option A and/or Option C GFAs.
2. Utilize the same path(s) (i.e. Source/Sink pair(s)) as entered in the "Filing Template" tab

Time of Use (Peak or Off-Peak)

4. If possible please provide data from 6/1/2009 - 5/31/2010

Definitions

Winter: December, January, February

Spring: March, April, May

Summer: June, July, August

Fall: September, October, November

Peak: 0700 hours EST through 2200 hours EST (Hour 7 and 22 inclusive) Monday through Friday except New Years, Memorial Day, Fourth of

Off-Peak: All periods of time not classified as Peak.

Source, Sink, & MW					
Source	**Sink**	**Total Scheduled MWh(s)**	**Total Hours Scheduled**	**Season**	**Time of Use (Peak or Off-Peak)**
BREC.HMP1.HMPL	BREC.HMPL	91,893	1122	Summer	Peak
BREC.HMP1.HMPL	BREC.HMPL	72,110	1085	Summer	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	74,681	1071	Fall	Peak
BREC.HMP1.HMPL	BREC.HMPL	65,849	1114	Fall	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	83,697	1054	Winter	Peak
BREC.HMP1.HMPL	BREC.HMPL	77,549	1106	Winter	Off-Peak
BREC.HMP1.HMPL	BREC.HMPL	79,067	1095	Spring	Peak
BREC.HMP1.HMPL	BREC.HMPL	62,601	1028	Spring	Off-Peak
Note: The source above is listed as BREC.HMPL1.HMPL however part of the source was also BREC.HMPL2.HMPL					

Transmission Owner Authorization Section	
TO Comments:	
The Transmission Owner submitting this information certifies that it is a correct and accurate representation of the rights pursuant to the terms and conditions of the GFA.	
Transmission Owner Name:	Big Rivers Electric Corporation
Transmission Owner NERC ID:	BREC
Primary Contact Name:	David G. Crockett
Date:	June 15, 2010
Signature:	David G. Crockett
Additional Contact Name:	Glen Thweatt
Additional Contact Email:	Glen.Thweatt@bigrivers.com
Additional Contact Phone:	(270) 844-6211
Additional Contact Name:	Chris Bradley
Additional Contact Email:	Chris.Bradley@bigrivers.com
Additional Contact Phone:	(270) 844-6201

Notes:
(i) Please submit multiple copies to obtain signatures from all Transmission Owners to the GFA

Market Participant Authorization Section	
MP Comments:	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	C. William Blackburn
Date	June 15, 2010
Signature	C William Blackburn
Additional Contact Name:	Bill Yeary
Additional Contact Email:	Bill.Yeary@bigrivers.com
Additional Contact Phone:	(270) 844-6168
Additional Contact Name:	Michael Mattox
Additional Contact Email:	Michael.Mattox@bigrivers.com
Additional Contact Phone:	(270) 844-6155

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

Market Participant Authorization Section	
The Market Participant/Responsible Entity(s) submitting this information certifies that it is a correct and accurate representation of the GFA Contract. The information submitted herein will be relied upon by the Midwest ISO in the administration of this GFA and will establish financially binding results for the Market Participant/Responsible Entity(s).	
Market Participant Name:	Big Rivers Electric Corporation
Market Participant NERC ID:	BRPS
Primary Contact Name:	City of Henderson
Date	
Signature	
Additional Contact Name:	
Additional Contact Email:	
Additional Contact Phone:	
Additional Contact Name:	
Additional Contact Email:	
Additional Contact Phone:	

Notes:
(i) Please submit multiple copies to obtain signatures from all parties to the GFA

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 31) ***Please provide documentation demonstrating that Henderson, as a party to Grandfathered Agreement No. 510, consented to the designation of Big Rivers as GFA Responsible Entity in accordance with the MISO Tariff Section 38.8.1.***

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any such documents other than the Station Two Contracts.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 32) ***Please provide documentation demonstrating that Henderson, as a party to Grandfathered Agreement No. 510, consented to the designation of Big Rivers as GFA Scheduling Entity in accordance with the MISO Tariff Section 38.8.2.***

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any such documents other than the Station Two Contracts.

Witness) Mark J. Eacret

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 33) ***Please provide documentation demonstrating that Henderson, as a party to Grandfathered Agreement No. 510, consented to the designation of the Transmission and Transformation Agreement between Henderson and Big Rivers as a Grandfathered Agreement with a Carve-Out Option pursuant to the MISO Tariff Section 38.8.3.***

a. Please explain the rationale underlying the designation of the agreement as a Grandfathered Agreement with a Carve-Out Option.

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any such documents other than the Station Two Contracts.

a. See Section 38.8 of the MISO Tariff for a discussion of the various Grandfathered Agreement alternatives.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Second Request for Information
dated June 17, 2020

June 29, 2020

Item 34) ***Is it Big Rivers' position that the administration of Grandfathered Agreement No. 510 caused Big Rivers to incur MISO charges, including charges under Schedule 17 and/or Schedule 23, for the period beginning on December 1, 2010, and ending on May 31, 2016? If yes, please explain.***

Response) Yes. Regardless of the Grandfathered Agreement status, the load and the generation would be subject to MISO administrative charges.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 35) ***Please provide all MISO settlement data reflecting any debits or credits Big Rivers received from MISO as a result of Auction Revenue Rights (ARRs) or Financial Transmission Rights (FTRs) held by Big Rivers in connection with Grandfathered Agreement Nos. 510 and 511.***

Response) Because Grandfathered Agreement Nos. 510 and 511 were carve-outs, there were no auction revenue rights associated with them and there was no need to purchase financial transmission rights.

Witness) Mark J. Eacret

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 36) ***Please provide documentation demonstrating that Henderson, as a party to Grandfathered Agreement No. 510, either supplied information to MISO or authorized Big Rivers to supply information to MISO regarding specific sources of Operating Reserves (Regulation, Spinning, and/or Supplemental) in accordance with MISO Tariff Section 38.8.4.1.***

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any such documents other than the Station Two Contracts.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 37) ***Please provide documentation demonstrating that Henderson, as a party to Grandfathered Agreement No. 510, either supplied information to MISO or authorized Big Rivers to supply information to MISO regarding Commercial Pricing Node Sources and Sinks and the Capacity associated with Grandfathered Agreement No. 510 in accordance with MISO Tariff Section 38.8.4.1.***

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any such documents other than the Station Two Contracts.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 38) ***Please provide any billing information Big Rivers supplied to the Transmission Provider for the Carved-Out Grandfathered Agreement Customer (including information pertaining to load data for Henderson), any adjustments to the Transmission Owner's load, and any credits received by Big Rivers under the Tariff relating to Schedule 10 and 17 charges applicable to Carved-Out Grandfathered Agreements prior to invoicing Henderson for Schedule 23 charges.***

Response) Please see the attached Henderson load data provided to MISO as required by MISO for the period December 1, 2010, through May 31, 2016. These load numbers were verified as correct by Henderson each month before Big Rivers created the submittal files and provided them to MISO. No adjustments were made to the Transmission Owners' load. Henderson load data submitted to MISO was a separate and discreet value.

Big Rivers did not receive credits for Schedule 10 or Schedule 17 applicable to Carved-Out Grandfathered Agreements prior to invoicing Henderson for Schedule 23 charges.

Witnesses) Michael W. Chambliss and
Mark J. Eacret

Big Rivers Electric Corporation
Case No. 2019-00269
2016 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	PEAK LOAD FOR NL1062 w/LOSSES	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	92	94	70.164	0	2.554	75.45	#DIV/0!
February	84	86	68.701	7	2.155	79.89	30.79
March	79	80	64.816	1	0.806	82.05	80.65
April	79	80	64.64	3	0.833	80.80	27.78
May	84	86	64.903	7	1.344	75.47	19.20
June	98	100	77.871	8	2.639	77.87	32.99
July	98	100	76.228	8	2.609	76.23	32.61
August	97	99	80.223	7	2.608	81.03	37.25
September	97	99	74.357	6	1.418	75.11	23.63
October	88	90	66.522	2	0.823	73.91	41.13
November	74	76	63.939	1	0.85	84.13	85.00
December	85	87	68.942	5	2	79.24	40.00

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

Big Rivers Electric Corporation
Case No. 2019-00269
2015 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	PEAK LOAD FOR NL1062 w/LOSSES	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	100		73.321	0	2.54	73.32	#DIV/0!
February	94		76.795	0	2.232	81.70	#DIV/0!
March	86		68.349	0	0.813	79.48	#DIV/0!
April	74		63.336	0	0.84	85.59	#DIV/0!
May	73		66.013	5	1.344	90.43	26.88
June	93	95	74.856	7	2.639	80.49	37.70
July	102	104	77.516	7	2.554	74.53	36.48
August	98	100	73.593	7	2.554	73.59	36.48
September	96	98	72.499	4	1.389	73.98	34.72
October	83	85	63.329	3	0.806	74.51	26.88
November	66	67	63.532	0	0.833	94.82	#DIV/0!
December	78	79	63.073	1	2.016	79.84	201.61

Note(s):
1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.
3.- A new template for data submittal was used beginning June 2015.

Big Rivers Electric Corporation
Case No. 2019-00269
2014 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	96	74.884	5	5.155	78.00	103.09
February	88	73.728	7	4.417	83.78	63.10
March	85	66.595	4	3.406	78.35	85.15
April	72	60.676	4	2.426	84.27	60.65
May	84	67.978	2	3.284	80.93	164.18
June	99	73.356	4	1.96	74.10	48.99
July	75	74.667	9	2.554	99.56	28.38
August	100	77.758	7	2.554	77.76	36.48
September	96	70.872	5	1.389	73.83	27.78
October	86	64.235	4	0.806	74.69	20.16
November	88	67.964	2	0.833	77.23	41.67
December	78	67.233	5	2.016	86.20	40.32

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

Big Rivers Electric Corporation
Case No. 2019-00269
2013 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	78	67.376	8	4.892	86.38	61.16
February	84	66.207	6	4.725	78.82	78.75
March	75	64.765	7	4.265	86.35	60.93
April	66	57.411	5	3.602	86.99	72.04
May	88	21.617	6	4.581	70.39	76.34
June	97	69.836	6	2.171	72.00	36.18
July	97	70.126	8	4.435	72.30	55.44
August	97	76.612	8	2.695	78.98	33.69
September	101	71.61	4	1.629	70.90	40.73
October	91	65.685	3	1.304	72.18	43.46
November	64	64.283	4	1.058	100.44	26.46
December	86	64.415	6	4.964	74.90	82.73

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

Big Rivers Electric Corporation
Case No. 2019-00269
2012 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	82	64.991	6	5.44	79.26	90.66
February	74	64.99	5	4.062	87.82	81.24
March	70	60.899	5	4.754	87.00	95.08
April	81	59.449	6	1.805	73.39	30.09
May	93	72.315	2	0.858	77.76	42.88
June	109	73.32	1	0.649	67.27	64.92
July	113	84.347	1	0.653	74.64	65.32
August	109	78.085	1	0.871	71.64	87.10
September	98	65.473	2	1.391	66.81	69.56
October	71	63.02	0	1.382	88.76	#DIV/0!
November	78	61.417	1	1.085	78.74	108.47
December	68	61.558	6	2.991	90.53	49.84

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

Big Rivers Electric Corporation
Case No. 2019-00269
2011 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January	87	72.823	3	2.801	83.70	93.37
February	86	62.751	3	2.071	72.97	69.04
March	72	59.84	6	5.81	83.11	96.84
April	70	56.437	6	5.169	80.62	86.16
May	96	58.918	5	5.456	61.37	109.11
June	104	53.749	5	5.456	51.68	109.11
July	105	53.749	3	5.456	51.19	181.85
August	110	81.981	1	1.34	74.53	134.01
September	106	65.712	1	1.228	61.99	122.85
October	82	62.993	1	1.13	76.82	113.30
November	59	58.794	6	2.595	99.65	43.26
December	77	60.285	5	5.52	78.29	110.40

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

Big Rivers Electric Corporation
Case No. 2019-00269
2010 Load Factor Data Submitted to MISO

MONTH	PEAK LOAD FOR NL1062	AVERAGE HOURL LOAD FOR NL1062	PEAK LOAD FOR NL1063	AVERAGE LOAD FOR NL1063	% LOAD FACTOR FOR NL1062	% LOAD FACTOR FOR NL1063
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December	66	6	66	4.49	100.10	74.80

Note(s): 1.- NL1062: GFA 510, HMPL Load excluding HMPL SEPA.
2.- NL1063: GFA 511, HMPL SEPA.

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 39) ***Please provide documentation demonstrating that Big Rivers was notified of the filing of an executed or unexecuted Schedule 23 Service Agreement with the Federal Energy Regulatory Commission (FERC) and produce copies of any FERC Orders permitting Big Rivers to assess Schedule 23 charges against Henderson.***

Response) Big Rivers objects to this request on the grounds that it is irrelevant and not likely to lead to the discovery of admissible evidence. Without waiving these objections, Big Rivers states that it is not aware of any requirement for such filings with FERC.

Witness) Mark J. Eacret

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 40) ***Please provide an accounting of any credit and/or revenue Big Rivers received from MISO for ancillary services associated with Station Two between 2010 and 2016.***

Response) There were approximately $18,000 in MISO ancillary services market revenues associated with Station Two between 2010 and 2013. There were no ancillary services market revenues thereafter.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 41) ***Provide the minimum reserve margin criteria used by Big Rivers in its 2010 Integrated Resource Plan filed with the Commission on November 15, 2010.***

a. Please explain the basis for this reserve margin.

Response) Big Rivers' Base Case Reserve margin in its 2010 Integrated Resource Plan was set to maintain planning reserves in excess of 14%.

a. This value was an approximation of the 15% reference margin level for predominantly thermal systems as shown in the North American Electric Reliability Corporation's 2009 Long-Term Reliability Assessment.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 42) ***Refer to Big Rivers' Revised Response to Item No. 7 of commission Staff's Initial Request for Information. Provide the source of the historical data reflecting Henderson's "projection of peak load."***

a. Refer to the document marked "HMPL Capacity Deficits" and attached to Big Rivers' Revised Response to Item No. 7 of Commission Staff's Initial Request for Information. Provide the coincident factor applied to calculate the figures in the column marked "HMPL Peak Demand mW."

Response) As noted in Big Rivers' response to Item 1 of Commission Staff's First Request for Information in Case No. 2016-00278,[1] "Annually, normally late in the year, Big Rivers will contact Henderson and request peak and Energy load forecast information for the following year. This information is necessary for internal Big Rivers' budgeting purposes and to determine Henderson's MISO Capacity

[1] *See In the Matter of: Application of Big Rivers Electric Corporation for a Declaratory Order* – Case No. 2016-00278.

requirement for the following year. Henderson provides a table showing this information on a total monthly basis."

a. The coincidence factor determined for HMPL for PY 17/18 was .951 and for PY 18/19 was .968 based on an estimate from GDS as requested by Big Rivers. Prior planning years used HMPL's forecasted July peak.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 43) ***Please provide all correspondence, communications, and other documentation dated between January 1, 2012, and December 31, 2018, in which Big Rivers communicated to Henderson that Henderson was deficient in meeting MISO's Resource Adequacy capacity planning requirements for the planning years 2013 through. Include any documentation specifying the degree to which Henderson was purportedly deficient and any documentation in which Big Rivers communicated to Henderson the steps or actions Henderson would have to take to correct the purported deficiency.***

Response) Please see the following attachments:

1. Attachment 1 – Henderson Municipal Power & Light Capacity Purchases Invoice and supporting schedules;
2. Attachment 2 – Marlene Parsley E-mail of June 26, 2017, including MISO's Resource Adequacy Business Practice Manual, effective July 15, 2016;
3. Attachment 3 – Marlene Parsley E-mail of June 27, 2017, including Henderson PRMR Calculation at June 27, 2017; MISO Peak Dates and

Times for 2005 - 2015, June – September; MISO Peak Forecasting Methodology Review Whitepaper; and HMP&L Load Forecast updated March 31, 2016;

4. Attachment 4 – Mark Eacret e-mail of February 12, 2018;
5. Attachment 5 – Mark Eacret e-mail of March 21, 2018, including Excel file showing Zonal Resource Credits and Mark Whole Payments example;
6. Attachment 6 – Mark Eacret e-mail of May 14, 2018, follow-up of his March 21, 2018, e-mail (Attachment 5);
7. Attachment 7 – Mark Eacret e-mail of May 16, 2018, at 9:30 AM; and
8. Attachment 8 – Mark Eacret e-mail of May 16, 2019 at 2:04 PM.

The shortfall would have also been discussed at any of several meetings held between Big Rivers and Henderson regarding disagreements on Station Two issues.

Witness) Mark J. Eacret

Invoice

Bill to:

Henderson Municipal Power and Light
Mr. Ken Brooks
P O Box 8
Henderson KY 42419-0008

Invoice # 418
Invoice Date February 13, 2018

Description	Energy (MWh)	Rate ($/MWh)	Total
MISO Capacity Purchase PY13/14			$1,379.70
MISO Capacity Purchase PY14/15			$116,161.25
MISO Capacity Purchase PY15/16			$2,292.62
MISO Capacity Purchase PY16/17			$81,468.00
MISO Capacity Purchase PY17/18			$2,354.25
		Balance Due	**$ 203,655.82**

Terms:

Past Due Penalty: Interest on unpaid amounts shall accrue at a rate of four percentage points over the then-effective prime commercial rate per annum published in the Money Rates section of *The Wall Street Journal* commencing on the first working day after the due date.

Wire transfer payment of invoice to the following account:

Old National Bank
Henderson, Kentucky
ABA # 086300012
Credit Big Rivers General Fund
Account # 10585559

Big Rivers Electric Corporation
P.O. Box 24
Henderson, KY 42419-0024
Phone: (270) 844-6156
Fax: (270) 827-2101
Website: www.bigrivers.com

Touchstone Energy®
The power of human connections

Big Rivers Electric Corporation
Case No. 2019-00269
HMPL Capacity Deficits
PY 2014/15 through PY 2017/18

	HMPL Peak Demand mW	Transmision Losses %	Planning Reserve Margin %	HMPL Planning Reserve Margin mW	HMPL 1 & 2 ICAP mW	HMPL 1 & 2 UCAP as established by MISO mW	HMPL Annual Reservation MW	HMPL Share of MISO Capacity adjustment (EFORd) mW	HMPL Share of MISO Station Two UCAP Capacity mW	HMPL SEPA Capacity as accredited by MISO mW	Total HMPL MISO Capacity (Reservation plus SEPA) mW	Excess / (Deficient) HMPL MISO Capacity mW	MISO Annual Auction Clearing Price ($/mW-Day)	MISO Monthly Capacity Revenue / (cost) - HMPL Share $
PY 13/14	115	1.3%	6.2%	123.6	312	293.1	115	7	108	12	120	(3.6)	$ 1.05	($1,379.70)
PY 14/15*	116	1.3%	7.3%	126	312	290.4	115	8	107	0	107	(19.0)	$ 16.75	($116,161.25)
PY 15/16	110	1.5%	7.1%	119.5	312	292.1	115	7.3	107.7	10	117.7	(1.8)	$ 3.48	($2,292.62)
PY 16/17	110	1.6%	7.6%	120.1	312	290.3	115	8	107	10	117	(3.1)	$ 72.00	($81,468.00)
PY 17/18**	103.7	2.2%	7.8%	114.2	310	270.6	115	14.6	100.4	9.5	109.9	(4.3)	$ 1.50	($2,354.25)
													Sum	($203,655.82)

* The SEPA Capacity for PY 14/15 did not clear the MISO annual planning year resource auction and was not compensated by MISO

** Coincidence factor determined for HMPL for PY 17/18. Prior years used HMPL's forecasted July peak

Big Rivers Electric Corporation
Case No. 2019-00269
Station Two Capacity Sales - HMPL Reservation

		Station Two Capacity mW	MISO Accredited Capacity (UCAP) mW	HMPL Reservation mW	HMPL Share of MISO Capacity adjustment (EFORd) mW	HMPL Share of MISO Station Two Capacity mW	HMPL SEPA Capacity mW[2]	Total HMPL MISO Capacity mW	HMPL Projected Peak Demand mW	HMPL Load Capacity Requirement mW	Excess/ (Deficient) HMPL MISO Capacity mW	MISO Annual Auction Clearing Price ($/mW-Day)	# of days in month	MISO Monthly Capacity Revenue - HMPL Share
PY 13/14[1]	Jun-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	30	($113.40)
	Jul-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Aug-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Sep-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	30	($113.40)
	Oct-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Nov-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	30	($113.40)
	Dec-13	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Jan-14	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Feb-14	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	28	($105.84)
	Mar-14	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
	Apr-14	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	30	($113.40)
	May-14	312	293.1	115.0	7.0	108.0	12.0	120.0	115.0	123.6	(3.6)	$ 1.05	31	($117.18)
PY 14/15	Jun-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	30	($9,547.50)
	Jul-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Aug-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Sep-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	30	($9,547.50)
	Oct-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Nov-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	30	($9,547.50)
	Dec-14	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Jan-15	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Feb-15	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	28	($8,911.00)
	Mar-15	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)
	Apr-15	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	30	($9,547.50)
	May-15	312	290.4	115.0	8.0	107.0	0.0	107.0	116.0	126	(19.0)	$ 16.75	31	($9,865.75)

Big Rivers Electric Corporation
Case No. 2019-00269
Station Two Capacity Sales - HMPL Reservation

		Station Two Capacity mW	MISO Accredited Capacity (UCAP) mW	HMPL Reservation mW	HMPL Share of MISO Capacity adjustment (EFORd) mW	HMPL Share of MISO Station Two Capacity mW	HMPL SEPA Capacity mW[2]	Total HMPL MISO Capacity mW	HMPL Projected Peak Demand mW	HMPL Load Capacity Requirement mW	Excess/ (Deficient) HMPL MISO Capacity mW	MISO Annual Auction Clearing Price ($/mW-Day)	# of days in month	MISO Monthly Capacity Revenue - HMPL Share
PY 15/16	Jun-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	30	($187.92)
	Jul-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Aug-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Sep-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	30	($187.92)
	Oct-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Nov-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	30	($187.92)
	Dec-15	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Jan-16	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Feb-16	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	29	($181.68)
	Mar-16	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
	Apr-16	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	30	($187.92)
	May-16	312	292.1	115.0	7.3	107.7	10.0	117.7	110.0	119.5	(1.8)	$ 3.48	31	($194.18)
PY16/17	Jun-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	30	($6,696.00)
	Jul-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Aug-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Sep-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	30	($6,696.00)
	Oct-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Nov-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	30	($6,696.00)
	Dec-16	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Jan-17	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Feb-17	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	28	($6,249.60)
	Mar-17	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)
	Apr-17	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	30	($6,696.00)
	May-17	312	290.3	115.0	8.0	107.0	10.0	117	110.0	120.1	(3.1)	$ 72.00	31	($6,919.20)

Big Rivers Electric Corporation
Case No. 2019-00269
Station Two Capacity Sales - HMPL Reservation

		Station Two Capacity mW	MISO Accredited Capacity (UCAP) mW	HMPL Reservation mW	HMPL Share of MISO Capacity adjustment (EFORd) mW	HMPL Share of MISO Station Two Capacity mW	HMPL SEPA Capacity mW[2]	Total HMPL MISO Capacity mW	HMPL Projected Peak Demand mW	HMPL Load Capacity Requirement mW	Excess/ (Deficient) HMPL MISO Capacity mW	MISO Annual Auction Clearing Price ($/mW-Day)	# of days in month	MISO Monthly Capacity Revenue - HMPL Share
PY17/18	Jun-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	30	($193.50)
	Jul-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Aug-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Sep-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	30	($193.50)
	Oct-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Nov-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	30	($193.50)
	Dec-17	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Jan-18	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Feb-18	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	28	($180.60)
	Mar-18	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
	Apr-18	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	30	($193.50)
	May-18	310	270.6	115.0	14.6	100.4	9.5	109.9	103.7	114.2	(4.3)	$ 1.50	31	($199.95)
													Total Capacity Revenue - Station Two HMPL Share:	**($203,655.82)**

Please Note:

[1]. The MISO Planning Reserve Annual Auction began for PY13/14.

[2]. The SEPA Capacity for PY 14/15 did not clear the MISO annual planning year resource auction and was not compensated by MISO.

Big Rivers Electric Corporation
Case No. 2019-00269
Capacity Requirement Calculation

		HMPL Projected Peak Demand mW	Effective Planning Year Margin Requirement (PRMR) %	Transmission Loss %	HMPL Load Capacity Requirement mW
PY 13/14	Jun-13	115	6.2%	1.3%	123.6
	Jul-13	115	6.2%	1.3%	123.6
	Aug-13	115	6.2%	1.3%	123.6
	Sep-13	115	6.2%	1.3%	123.6
	Oct-13	115	6.2%	1.3%	123.6
	Nov-13	115	6.2%	1.3%	123.6
	Dec-13	115	6.2%	1.3%	123.6
	Jan-14	115	6.2%	1.3%	123.6
	Feb-14	115	6.2%	1.3%	123.6
	Mar-14	115	6.2%	1.3%	123.6
	Apr-14	115	6.2%	1.3%	123.6
	May-14	115	6.2%	1.3%	123.6
PY 14/15	Jun-14	116	7.3%	1.3%	126
	Jul-14	116	7.3%	1.3%	126
	Aug-14	116	7.3%	1.3%	126
	Sep-14	116	7.3%	1.3%	126
	Oct-14	116	7.3%	1.3%	126
	Nov-14	116	7.3%	1.3%	126
	Dec-14	116	7.3%	1.3%	126
	Jan-15	116	7.3%	1.3%	126
	Feb-15	116	7.3%	1.3%	126
	Mar-15	116	7.3%	1.3%	126
	Apr-15	116	7.3%	1.3%	126
	May-15	116	7.3%	1.3%	126

Big Rivers Electric Corporation
Case No. 2019-00269
Capacity Requirement Calculation

		HMPL Projected Peak Demand mW	Effective Planning Year Margin Requirement (PRMR) %	Transmission Loss %	HMPL Load Capacity Requirement mW
PY 15/16	Jun-15	110	7.1%	1.5%	119.5
	Jul-15	110	7.1%	1.5%	119.5
	Aug-15	110	7.1%	1.5%	119.5
	Sep-15	110	7.1%	1.5%	119.5
	Oct-15	110	7.1%	1.5%	119.5
	Nov-15	110	7.1%	1.5%	119.5
	Dec-15	110	7.1%	1.5%	119.5
	Jan-16	110	7.1%	1.5%	119.5
	Feb-16	110	7.1%	1.5%	119.5
	Mar-16	110	7.1%	1.5%	119.5
	Apr-16	110	7.1%	1.5%	119.5
	May-16	110	7.1%	1.5%	119.5
PY16/17	Jun-16	110	7.6%	1.6%	120.1
	Jul-16	110	7.6%	1.6%	120.1
	Aug-16	110	7.6%	1.6%	120.1
	Sep-16	110	7.6%	1.6%	120.1
	Oct-16	110	7.6%	1.6%	120.1
	Nov-16	110	7.6%	1.6%	120.1
	Dec-16	110	7.6%	1.6%	120.1
	Jan-17	110	7.6%	1.6%	120.1
	Feb-17	110	7.6%	1.6%	120.1
	Mar-17	110	7.6%	1.6%	120.1
	Apr-17	110	7.6%	1.6%	120.1
	May-17	110	7.6%	1.6%	120.1

Big Rivers Electric Corporation
Case No. 2019-00269
Capacity Requirement Calculation

		HMPL Projected Peak Demand mW	Effective Planning Year Margin Requirement (PRMR) %	Transmission Loss %	HMPL Load Capacity Requirement mW
PY17/18	Jun-17	103.7	7.8%	2.2%	114.2
	Jul-17	103.7	7.8%	2.2%	114.2
	Aug-17	103.7	7.8%	2.2%	114.2
	Sep-17	103.7	7.8%	2.2%	114.2
	Oct-17	103.7	7.8%	2.2%	114.2
	Nov-17	103.7	7.8%	2.2%	114.2
	Dec-17	103.7	7.8%	2.2%	114.2
	Jan-18	103.7	7.8%	2.2%	114.2
	Feb-18	103.7	7.8%	2.2%	114.2
	Mar-18	103.7	7.8%	2.2%	114.2
	Apr-18	103.7	7.8%	2.2%	114.2
	May-18	103.7	7.8%	2.2%	114.2

[redacted]

From: Parsley, Marlene
Sent: Monday, June 26, 2017 8:09 AM
To: Brad Bickett; Eacret, Mark
Cc: Ken Brooks
Subject: RE: MISO Capacity Questions
Attachments: BPM-011-r16 Resource Adequacy_CLEAN.pdf

Good Morning, Brad

In preparing for tomorrow's 8 AM Resource Adequacy call with MISO, I realized the attached may be useful for you to have handy during the call, and afterward. It is the current version of the MISO Business Practice Manual on Resource Adequacy. It is also available at the link below.

https://www.misoenergy.org/Library/Repository/Tariff%20Documents/BPM%20011%20-%20Resource%20Adequacy.zip

Regards,

Marlene Parsley
Director, Resources and Forecasting
Big Rivers Electric Corporation
[redacted]

From: Parsley, Marlene
Sent: Wednesday, June 21, 2017 2:19 PM
To: 'Brad Bickett' ; Eacret, Mark J
Cc: Ken Brooks
Subject: RE: MISO Capacity Questions

Hi, Brad

I forwarded you MISO's meeting invitation for a call next Tuesday at 8 AM Henderson time. Please let me know if this time is not convenient for you. You're welcome to forward to others who may be interested in this discussion.

Call in details will follow.

THANKS

Marlene Parsley

Director, Resources and Forecasting
Big Rivers Electric Corporation
[redacted]

[redacted]

From: Brad Bickett [[redacted]]
Sent: Wednesday, June 21, 2017 10:25 AM
To: Eacret, Mark J <[redacted]>
Cc: Parsley, Marlene <[redacted]>; Ken Brooks <[redacted]>
Subject: RE: MISO Capacity Questions

Mark,

Next Tuesday would work best for us, and yes I do have the following questions in mind:

- In general, what are the resource adequacy requirements for a generator owner / load serving entity in MISO? Are there exceptions or alternative methods to demonstrate resource adequacy for smaller load serving entities?
- For capacity reserve margin requirements, is there consideration for capacity available on a first call basis from one of two individual generating units with each unit having capacity to supply peak load requirements?
- Does load factor play any part in the reserve margin requirement?

The most recent figures of EHE value are through April (attached).

Brad

From: Eacret, Mark J [[redacted]]
Sent: Wednesday, June 21, 2017 8:48 AM
To: Brad Bickett
Cc: Parsley, Marlene
Subject: MISO Capacity Questions

Brad,

We have spoken with Carmen Clark at MISO and we are trying to schedule something either Thursday, Friday, or next Monday. She asked if you had any specific questions that you could send them in advance, they could make sure that they had the correct person on the phone.

Is any particular day better for you and Ken?

Also, could you send me the latest version of your historical view of the value of EHE? I want to make sure that I'm not using an old version.

Mark J. Eacret

Vice President Energy Services
Big Rivers Electric Corporation
[redacted]

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Manual No. 011

Business Practices Manual

RESOURCE ADEQUACY

Case No. 2019-00269
Attachment 2 for Response to HMPL 2-43
Witness: Mark J. Eacret

Disclaimer

This document is prepared for informational purposes only to support the application of the provisions of the Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) of the Midcontinent Independent System Operator, Inc. (MISO), Tariff and the services provided under the Tariff. MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff.

This Business Practices Manual (BPM) contains information to augment the field and accepted Tariff. In all cases the Tariff is the governing document and not the BPMs. Additionally, if not otherwise defined herein, all capitalized terms in this BPM have the meaning as defined in the Tariff.

Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-011-r16	Several updates. Updated Wind UCAP values; added section regarding Solar capacity credit; Revised provisions for Zonal Deliverability Benefit; Inclusion of Suspended resources in the PRA; Retail Choice coincident load forecast reporting process. Annual Review completed.	J. Harmon	JUL-15-2016
BPM-011-r15	Annual Review completed. Included Inter-zonal replacement, sub regional constraints in PRA, PRMR and LCR relationship, external resource and host BA qualification requirements, GVTC deferral, and refueling versus repowering. Additions to section 5.2.1 for Local Resource Zone reevaluation process and Generation Limited Transfers	J. Milli / M. Sutton / S. Quadri / J. Cole / R. Westphal	SEP-01-2015
BPM-011-r14	Annual Review completed. Remove netting of Demand Response. Update SFT and Transfer Analysis provisions.	J. Milli	SEP-01-2014
BPM-011-r13	Updated LRZ map, timeline, and added catastrophic outage provisions	C. Clark	JAN-01-2014
BPM-011-r12	Annual review and updated to reflect Tariff orders	C. Clark	AUG-01-2013
BPM-011-r11	Updated to reflect Module E-1-1 Tariff	C. Clark	OCT-01-2012
BPM-011-r10	Updated GVTC language for Hydro and ROR.	C. Clark	SEP-28-2012
BPM-011-r9	Annual Review completed and Updated Registration tables and added new section for qualifying PPAs.	C. Clark	APR-15-2012
BPM-011-r8	MISO Rebranding Changes JUL-19-2011	G. Krebsbach	JUN-13-2011
BPM-011-r8	Annual Review and added Dispatchable Intermittent Resource, minor clarifications	C. Clark	JUN-13-2011
BPM-011-r7	Updated UCAP calculations for plan year 2011/2012, undated Must-offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications	M. Heraeus / C. Clark	Dec-1-2010
BPM-011-r6	Corrected errors and added “Must-Offer” language and Units with Low Service Hours	M. Heraeus / C. Clark	JUN-1-2010
BPM-011-r5	Corrected errors and inadvertent omissions	M. Heraeus	MAR-3-2010
BPM-011-r4	Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011	K. Larson	DEC-21-2009
TP-BPM-003-r3	Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1.	T. Hillman	JUN-01-2009
TP-BPM-003-r2	Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements	T. Hillman	JUN-01-2009

TP-BPM-003-r1	Revised to reflect 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.	J Moser	JAN-06-2009
TP-BPM-003	Updated template	J. Moser	APR-01-2008
N/A	Section 3.2.1 Determination of Requirements – Non-valid statements were removed. Section 3.2.3 Default Requirements – Minor revisions were made for clarification. Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR "must offer" compliance was removed. Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification. Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification. Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted. Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR "must offer" compliance was removed. Section 5.5 Financial Transmission Rights – This section was deleted. Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions. Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890. Section 6.1.4 Hubbing Transactions – This section was deleted. Section 8 Data Requirements – Entire section updated to reflect FERC order 890		DEC-12-2007

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1. Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Resource Adequacy Requirements includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. 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, and business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the MISO Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

1.2. Purpose of this Business Practices Manual

This Resource Adequacy Business Practice Manual describes MISO's and other entities' roles and responsibilities related to maintaining Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines and standards in order to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- How is Resource Adequacy determined?
- How do the multiple state jurisdictions relate with regard to Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities with regard to Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?

- What are the deliverability requirements for Planning Resources?
- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under the changes to Module E-1 of the Tariff?
- What are the procedures for participating in the annual and Transitional Planning Resource Auctions?
- What are the settlement provisions for the annual and Transitional Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

1.3. References

Other reference information related to this document includes:

- MISO BPMs
- MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004
- Federal Energy Regulatory Commission (FERC) Order Nos. 890, Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- LOLE Study Reports
- PowerGADS User's Manual

2. Overview of Resource Adequacy

Achieving reliability in the bulk electric systems requires, among other things, that the amount of resources exceeds customer demand by an adequate margin. The margins necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed thru the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance
- Unplanned or forced outages of generating equipment
- Deratings in the capability of Generation resources and Demand Response Resources
- System effects due to reasonably anticipated variations in weather
- Load Forecast Uncertainty

2.1. Planning Reserve Margin Requirement Overview

Each LSE's total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Forecasted Coincident Peak Demands are submitted by LSE's using a 50%-50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the actual peak demand) which will include distribution losses. An LSE's PRMR is described in Section 3.1 of this BPM.

2.2. Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency Resources. The relationships and key attributes of the Planning Resource types are as follows:

- Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of MISO), and resources that can be dispatched to reduce demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market and are available during emergencies. Capacity Resources are quantified by applying forced outage rates to Installed Capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.

- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during all types of emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.
- A Market Participant (MP) can use Capacity Resources, LMRs, and Energy Efficiency Resources, up to their UCAP values, to comply with their Resource Adequacy Requirements via a Fixed Resource Adequacy Plan as described in Section 5.3 of this BPM, or a Market Participant can sell the UCAP values from Capacity Resources, LMRs, and Energy Efficiency Resources, either bilaterally before the Planning Resource Auction or in the Planning Resource Auction as described in Section 5.5 of this BPM.

MISO will determine annual Unforced Capacity (UCAP) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each Planning Year.

2.3. Resource Adequacy Requirements Overview

Planning Resources that clear in a Planning Resource Auction or Transitional Planning Resource Auction (TPRA) or that are designated in a Fixed Resource Adequacy Plan (FRAP) will be obligated to provide capacity the entire Planning Year unless replaced by another Planning Resource. LSEs that serve Load during the Planning Year will be obligated to pay for capacity from such Planning Resources pursuant to the relevant Auction Clearing Price (ACP) for the LRZ where the Load is located, unless the Planning Resource was designated in a FRAP.

LSEs that have a Planning Reserve Margin Requirement (PRMR) will be obligated to procure capacity equal to their Planning Reserve Margin Requirement pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone where they have PRMR unless, and to the extent that the LSE meets its PRMR via a Fixed Resource Adequacy Plan (FRAP) per Section 5.3 of this BPM, or unless and to extent that the LSE chooses to reduce its PRMR that is cleared in the auction by electing to pay the Capacity Deficiency Charge per section 5.6 of this BPM.

2.4. Settlements/Performance Requirements Overview

The Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be fixed for the Planning Year and they will be settled based upon the Planning Resource Auction (PRA) clearing price for an LSE's Planning Reserve Margin Requirement, unless covered by a Fixed Resource Adequacy Plan (FRAP) or Capacity Deficiency Charge. Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable annual and Transitional PRA included on their daily settlements statements for all loads and Planning Resources cleared in an annual or Transitional PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA or were used in a FRAP will have a performance obligation to be available during system emergencies.

3. Establishing Planning Reserve Margin Requirement

3.1. Overview

The Planning Reserve Margin Requirement (PRMR) is the number of ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load.

The PRMR is expressed in the following equation per Asset Owner per Local Resource Zone (LRZ):

$$PRMR_{LRZ} = \sum_{LBA} [(CPDf \quad - FRP \quad + FRS \quad) \times (1 + TL\% \quad) \times (1 + PRM_{RTO})]$$

Where:

$PRMR_{LRZ}$ = Planning Reserve Margin Requirement per LRZ
CPDf = Coincident Peak Demand forecast per LBA
FRP = Full Responsibility Purchase per LBA
FRS = Full Responsibility Sale per LBA
TL% = Transmission Loss Percentage of LBA
PRM_{RTO} = Planning Reserve Margin in Unforced Capacity set by LOLE Studies

3.1.1. Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity would perform functions on behalf of the applicable LSE including but not limited to submitting the LSE's forecasted CPD forecast or share of CPD forecast.

Each individual LSE is ultimately responsible for conformance with the RAR, even if it enters into a contract with a third party acting on its behalf. Each LSE that contracts with another entity to comply with any part of the Resource Adequacy Requirements must notify MISO of the arrangement. The LSE must provide MISO with: the name of the organization representing them; primary and alternate contact information for the individuals representing them; and the scope of responsibilities the contracted entity will provide.

3.1.2. Validation of Firm Transmission Service for Load

Each LSE shall document as described in Module B – Transmission Service BPM to MISO that the LSE has obtained sufficient firm Transmission Service for the entire Planning year for its

Load to be served. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement, when applicable. However, demand does not require firm MISO Transmission Service when the LSE meets its PRMR using its own Behind-the-Meter Generation (BTMGs), Demand Resources (DRs) and Energy Efficiency Resources (EERs), and does not use the MISO Transmission System to serve such demand.

3.2. Demand and Energy Forecasts

MISO collects a variety of load forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them. Please See Appendix O for the list of parties responsible for reporting demand and energy forecasts.

Demand and Energy that is not subject to retail choice switching should be reported by the respective LSE. Demand and Energy that is subject to retail choice switching should be reported by the respective Electric Distribution Company ("EDC"). The EDC calculates a Peak Load Contribution ("PLC") MW value for each retail choice LSE that is each LSE's share of the EDC's PRMR. If an LSE disagrees with their PLC value calculated by their EDC, the LSE will first work with its EDC to revise the PLC prior to informing MISO.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.1. Non-Coincident Peak Demand and Energy for Load Forecasts

Non-coincident peak demand and energy for load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-coincident peak demand forecast and FERC's form 714 for the energy for load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective standards documents, defer to the latter.

The non-coincident peak demand and energy for load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:

Summer: June through November

Winter: December through May

For seasonal reporting of the non-coincident peak demand forecast the single highest peak hour during the season should be reported in MW. For energy for load forecasts, the summation of each month's energy for load (GWh) should be reported.

For all forecasts submitted, each LSE shall ensure that it counts its customer demand once and only once.

For a detailed description of each forecast's characteristics refer to Appendix N.

3.2.2. Coincident Peak Demand Forecast

The Coincident Peak Demand forecast (CPD forecast) is used to determine each LSE's Planning Reserve Margin Requirement. The CPD forecast shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing in detail the desired approach to be used by LSEs in preparing the CPD forecast, the information required in each annual filing, and the process used in reviewing the CPD forecast can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper

The CPD forecast must be provided by the Asset Owner and the LBA. Providing the CPD forecast by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the applicable Transmission Losses. Transmission Losses will be reported on the Market Portal by MISO for each LBA for the annual peak Hour..

The CPD forecast must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecast is reported differently in non-retail choice and retail choice areas as described in the following subsections.

3.2.3. Forecast Reporting

LSEs with demand and energy that is not subject to retail choice switching are required to provide MISO with demand and energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The CPD forecast must be reported for each Asset Owner by LBA.

LSEs with demand and energy that is subject to retail choice switching are not required to provide MISO with demand and energy forecasts. Electric Distribution Companies are responsible for submitting forecasts in areas that have demand and energy that is subject to retail choice switching.

Electric Distribution Companies (EDCs) are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area provides MISO with an annual peak forecasted Demand coincident with MISO's annual peak and must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs must provide both MISO and the respective LSEs with each retail customer's Peak Load Contribution (PLC) in the EDC's service territory by no later than 11:59 p.m. on December 15th prior to the Planning Year.

All new EDCs are required to work with the MISO Customer Service department (register@misoenergy.org,), to set up access to the MECT tool and the relationships between the EDC and the LSEs in the EDC area. The MISO Customer Service team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the Retail Choice program are required to provide the name of the EDC where the commercial pricing node is located.

3.2.3.1 Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any PRMR from demand left unclaimed by LSEs in the EDC service territory. The Transmission Provider will work with POLR and EDC to ensure that POLR will serve any remaining demand that is not allocated to LSE's.

3.2.4 Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the demand and energy attributed to those wholesale customers in their demand and energy forecasts by November 1st prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

Case 1: LSE knows the entity that will serve the wholesale customer next Planning Year:
In this case the existing LSE is not responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

Case 2: LSE does not know who will serve the wholesale customer next Planning Year:
In this case the existing LSE is responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to work to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the demand from the old LSE to the new LSE prior to the Planning Resource Auction.

3.2.5 Review of CPD forecast

Starting November 1st, MISO will begin reviewing all forecasts and supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether or not the forecast methodology adequately and reasonably forecasts peak demand, energy, and/or demand reduction capability of the submitting entity. LSEs will be able to view the status (approved or pending review) of their CPD forecast in the MECT. The forecast review process will be completed no later than March 1st of each year prior to the annual PRA. MISO will develop the required forecast for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity of other Market Participants that do not submit a CPD forecast and supporting documentation by the November 1st deadline.

3.3 Placeholder

3.4 Full Responsibility Transactions

Full responsibility transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of a FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of demand. As a result, the PRMR calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for demand that is not subject to retail choice switching.

The FRS results in an increase in demand and FRP results in a decrease in demand. This can be interpreted as the purchaser paying the seller to take on demand and its associated PRMR. This transfer of demand results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within MISO's Region, sellers are responsible for all of that LSE's PRMR associated with the sale

  Example:

  Asset Owner MM1:
  CPDf = 10 MW
  PRM = 6.2%
  Transmission Loss % = 2%
  Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
  MM1's PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

  Asset Owner SS2:
  CPDf = 20 MW
  PRM = 6.2%
  Transmission Loss % = 2%
  Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
  SS2's PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

  Asset Owner BB3:
  CPDf = 50 MW
  PRM = 6.2%

Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3's PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon ACP for all or part of its load delivered to the purchaser, through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted CPD information for the transferred Demand into the MECT. A MP with an FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. If the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of MISO, then the purchaser under an FRP/FRS agreement will remain responsible for any capacity payments associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE under the jurisdiction of MISO, then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. Such a purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from responsibilities for any RAR deficiencies associated with the FRP/FRS agreement.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand remains with the original LSE (purchaser).

In accordance with the following formula found in Section 69A.2 of the Tariff, the PRM for the LRZ in which the load resides will be applied to the load regardless of which LSE or MP has the reserve obligation.

The purchasing and selling parties will be required to enter and verify the FRP/FRS transaction into the MECT full responsibility transactions screen. The parties must enter an FRP/FRS transaction into the MECT as a full responsibility transaction to enable MISO to track the load and capacity obligations shift. This must be done prior to the closing of the PRA window and the settlement will be between LSEs for all FRP/FRS transactions. The PRMR cannot be a negative number as a result of the FRT.

3.5 Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process and the process used by MISO to establish the Planning Reserve Margin (PRM) for the MISO Planning Year. A MISO Planning Year runs from June 1 through May 31 of the following year.

3.5.1 Determination of PRM

MISO will perform a technical analysis on an annual basis to establish the PRM and Local Reliability Requirement for Local Resource Zones for the MISO Region, recognizing internal transmission limitations, and will publish the results by November 1st preceding the applicable Planning Year. The analysis includes calculating the Local Clearing Requirement (LCR), the Capacity Import Limit (CIL), and the Capacity Export Limit (CEL).

The LOLE study shall be consistent with Good Utility Practice, the reliability requirements of the Regional Entities (RE), and applicable states in the MISO Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMR) and EE Resources, load forecast uncertainty, and the Transmission System's import and export capability with external systems. Because Capacity Resources are being credited at their UCAP value the reserve requirements must also use a UCAP rating to be equitable. The PRM that is calculated in the LOLE study software is determined on an ICAP basis. This $PRMR_{ICAP}$ value is the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the UCAP ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total UCAP rated MW needed, or the $PRMP_{UCAP}$.

MISO will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

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Previous LOLE studies were based on the LSE forecasts that were Non-coincident with the MISO system peak. Based on the LSE forecast at time of MISO peak under the new construct starting in PY 2013-2014, the Planning Reserve Margins that would have been determined for past Planning Years are shown in the table below:

	Coincident Load Based[1] (UCAP)	MISO System wide Forced Outage Rate (XEFORd)	Coincident Load Based (ICAP)
Planning Year (2009-2010)	7.89%	6.51%	15.40%
Planning Year (2010-2011)	7.74%	6.64%	15.40%
Planning Year (2011-2012)	8.76%	7.36%	16.10%
Planning Year (2012-2013)	8.80%	6.77%	16.7%
Planning Year (2013-2014)[1]	6.2%	6.46%	14.2%
Planning Year (2014-2015)	7.3%	6.4%	14.8%
Planning Year (2015-2016)	7.1%	6.95%	14.3%
Planning Year (2016-2017)	7.6%	6.86%	15.2%

[1] Applicable to Forecast LSE Requirement at time of MISO peak

See MISO's website for current and previous LOLE Study reports.

3.5.2 LOLE Analysis

MISO will determine the appropriate PRM for the applicable Planning Year based upon the probabilistic analysis of being able to reliably serve MISO's Coincident Peak Demand. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations. MISO will annually calculate the PRM such that the LOLE is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined using the LOLE analysis by either adding a perfect, zero EFORd, negative unit or removing Planning Resources until a 0.1 day per year solution is reached. The LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable to adding coincident peak demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. MISO will also determine the Local Resource Requirement for each zone consistent with the LOLE achieving 0.1 day per year. The minimum amount of capacity above Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system wide PRM and the Local Reliability Requirement (LRR) for each Local Resource Zone.

3.5.3 Loss of Load Expectation (LOLE) Working Group

MISO has established an Unforced Capacity requirement based on the LOLE analysis conducted by the LOLE Working Group (LOLEWG) for the purpose of coordinating PRM study work with stakeholders. The duties of the working group are to help guide MISO in implementing the study methods outlined in the following sections. The LOLEWG will work with MISO staff to perform the LOLE analysis that calculates the PRM requirements for each LSE within MISO. This analysis will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable REs for reliability and resource adequacy. The LOLEWG will also review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analysis, as well as reviewing the results of the LOLE analysis and related sensitivity cases. The LOLEWG will use this information as the basis for providing recommendations on the PRM and LRR's to MISO.

3.5.4 Probabilistic Analysis LOLE Study

The probabilistic study will use the General Electric's Multi-Area Reliability Simulation (GE MARS) software application. Primary inputs are the generation data submitted to MISO through the PowerGADS tool and forecasted Demands provided as described in Section 3. Aside from the generation outage performance that has statistical parameters, the GE MARS model requires information to model sub-areas or zones in the Energy and Operating Reserves market and also to model transmission capability among such zones. LSEs are obligated to report GADS data for Generation Resources and External Resources through the PowerGADS tool in the MISO Market Portal. The specific XEFORd outage parameter is developed from this data and together with the capacity of each resource are the key generator inputs to the GE MARS application. The XEFORd and EFORd metrics are more fully described below. The zones to be modeled in the MARS application are discussed in Section 5.2 Local Resource Zones.

Although the compliance rating for individual generators will be based on the XEFORd metric, the LOLE study also will account for additional system wide outages beyond the outage causes captured in the XEFORd metric. The XEFORd metric focuses on the manageable performance differences among individual generators. There are also outages, however, that are caused by Force Majeure conditions that are outside of management control and can result in Generation Resources being unavailable, for example, due to weather conditions. The distinction is tracked with two specific forced outage rate metrics, $EFOR_d$ and $XEFOR_d$. The two terms are defined as:

> Equivalent demand Forced Outage Rate ($EFOR_d$): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
>
> $XEFOR_d$: Same meaning as $EFOR_d$, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example, losses of transmission outlet lines are considered as OMC relative to a unit's operation.

OMC Codes approved by stakeholders for use in the MISO LOLE study are listed in Appendix B.

The accommodation of Force Majeure outage causes by using the $EFOR_d$ metric as the input data to the GE MARS application is normal; however, a sensitivity run with the $XEFOR_d$ metric will normally be done to examine the impact of the Force Majeure event. Similarly, the allowance for carrying contingency reserves may be used as an input to the GE MARS application to study the impact of covering contingency reserve or any other component of operating reserves that may be desirable to quantify.

3.5.5 State authority to set PRM

The only entity other than MISO that may establish a PRM is a state regulatory body regarding those regulated entities under their jurisdiction. If a state regulatory body establishes a minimum PRM for the LSEs under their jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in such state. If a state regulatory body establishes a PRM that is higher than the MISO established PRM, the affected LSEs must meet the state set PRM. Similarly, if a state regulatory body establishes a PRM that is lower than the MISO established PRM, then the affected LSEs must meet the state set PRM. Other entities, such as reserve sharing groups or

NERC regional entities, do not have the authority to establish a PRM under Module E-1. MISO will translate any state-set PRM into the same terms as MISO's PRM (e.g. utilizing a UCAP basis) to facilitate comparison and compliance with PRMR.

4 Qualifying and Quantifying Planning Resources

4.1 Overview

MISO has worked with its stakeholders in order to build consensus regarding the processes required to qualify Planning Resources. This section identifies the qualification requirements for each type of Planning Resource.

All Planning Resources that qualify will have a UCAP value determined by MISO.

The benefits of UCAP include:

- Fair recognition of the contribution each unit provides towards Resource Adequacy;
- Market signals that will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the UCAP value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs

Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources are resources registered with MISO that permanently reduce electricity demand.

Generation Resources and Demand Response Resources backed by behind the meter generation in the Commercial Model that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have UCAP MWs calculated based on data submitted by the Asset Owner, as described in the Appendix H of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources and Demand Response Resources backed by behind the meter generation that have not provided at least one year of historical performance data will have their UCAP calculated for them after they are listed in MISO's Commercial Model provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA they are physically located in. The following Table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

	Planning Resource				
	Capacity Resource		Load Modifying Resource		
	Generation and External	Demand Response Resources	BTMG	Demand Resource	Energy Efficiency Resource
Capacity Verification [1]	X	X	X	X	X
Must Offer [1]	X[3]	X			
GADS Data Entry	X[2]	X[3, 2]	X[2]		
Must Respond to	X	X	X	X	
Emergency Operating Procedures	X	X	X	X	

1 - Includes Intermittent Capacity with must offer requirement met as price taker in the DA Market.

2 - BTMG greater than 10 MW must supply GADS

3 – If backed by generation..

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4.2 Planning Resources

4.2.1 Non-Intermittent Generation Resources

4.2.1.1 Non-Intermittent Generation - Qualification Requirements

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within MISO's Region. The deliverability of Generation Resources to Network Load within MISO's Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. Generation Resources that pass the deliverability test receive Network Resource Interconnection Service.
- Generation Resources that do not pass the deliverability test may procure Firm transmission service in conjunction with Energy Resource Interconnection Service (ERIS) to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Generation Resources with ERIS may participate in MISO's Interim Deliverability Study process as described in BPM-015. The following generic parameters apply for the Interim Deliverability Study:
    - MISO may grant conditional NRIS applicable for the next Planning Year
    - MISO may grant conditional ERIS applicable for the next Planning Year
    - MISO may implement a Quarterly Operating Limit (QOL) on a portion of a Generation Resource due to transmission study overloads. MW amount subject to QOL can qualify as capacity in the PRA. The MW amount subject to QOL is not required to procure replacement capacity if the QOL is reduced in a subsequent MISO quarterly study.
- Generation Resources with a Provisional Interconnection Agreement are not qualified to participate in the PRA.
- Generation Resources that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.

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- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- Generation Resources greater than or equal to 10 MW (based on Generation Verification Tested Capacity (GVTC) must submit their Generator Availability Data (GADS) (including, but not limited to, NERC GADS) into the MISO PowerGADS database through the MISO Market Portal.
- Generation Resources less than 10 MW based upon GVTC are not required to report their GADS data.
- Generation Resources less than 10 MW based upon GVTC that begin reporting GADS must report GADS each Planning Year.
- The XEFORd for new Generation Resources in service less than twelve full calendar months will be the EFORd class average for the resource type. A Generation Resource will use the class average value until 12 consecutive months of data is available.
- Generation Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- Generation Resources that are in approved "Suspension" status qualify as a Planning Resource.
- If Generation Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date. Generation Resources with approved "Suspension" status must participate as a Planning Resource in the next Planning Year subject to provisions regarding physical withholding in Module D of the Tariff.
- Generation Resources that plan to retire during the Planning Year be will be subject to test for Physical Withholding.
- Generation Resources that are or plan to be suspended will be subject to test for Physical Withholding.
- Generation Resources that have been designated as a System Support Resource (SSR) may participate in the PRA.
- Generation Resources must demonstrate capability on an annual basis as described below.
- Generation Resources undergoing gas conversion are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource's rolling XEFORd.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be completed by completing a real power test or based on operational data. The GVTC must be completed during the test period of September 1st through August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and a revised GVTC should be submitted to MISO no later than March 1st prior to the Planning Year. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a suspended state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).
- A real power test is required for Planning Resources in an approved “Suspension” status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item, including timing and cost requirements, when requesting a facility specific reference level.
- The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1st prior to the Planning Year. See Appendix J for links to MISO’s GVTC Manual and processes.

Reporting is accomplished through MISO’s PowerGADS reporting system as described in Net Capability Verification Test User Manual

4.2.1.2 Non-Intermittent Generation Resources – UCAP Determination

The UCAP value for a Generation Resource is based on an evaluation of the type and volume of interconnection service, GVTC value, and $XEFOR_d$ value of such Generation Resource as described in Appendix H-I.

The UCAP methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average $EFOR_d$ of all the pooled resources, the generating units with better than average availability will reflect higher values than units with below average availability.

4.2.1.3 Non-Intermittent Generation Resource – Must-Offer Performance Requirements

As described in detail in Section 6.1 , an MP that owns a Capacity Resource with ZRCs that clear in an annual or Transitional PRA or identified in a Fixed Resource Adequacy Plan (FRAP) must submit the full operable capacity of the Resource, but not less than the ICAP equivalent of the cleared or FRAP ZRCs, and make an Offer into the Day-Ahead Energy market and the first post Day-Ahead Reliability Assessment Commitment (RAC), for every hour of every day, except to the extent that the Capacity Resource is unavailable due to a full or partial forced scheduled outage. Outages and derates must be reported in the MISO Outage Scheduler (CROW).

Compliance with “must offer” requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze compliance with must offers in both the Day-Ahead and RAC by taking into account information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

4.2.2 GVTC Deferral

Zonal Resource Credits (ZRC) will be awarded to an untested new Planning Resource; an existing Planning Resource that is returning from a catastrophic outage, suspension or increasing capability; or is currently in an approved “Suspension” status if the Market Participant (MP) provides written notification to MISO (radequacy@misoenergy.org) by February 15th prior to the upcoming Planning Year stating that the Planning Resource will perform a real power test to submit its GVTC after March 1st, but before the last business day of May, prior to the upcoming Planning Year. The written notification must be from an officer of the company and must include the information below. Additionally, once the GVTC is performed information pertaining to it must be submitted via written notification to MISO (radequacy@misoenergy.org).

- Company name
- NERC ID of company
- Planning Resource name
- Local Resource Zone (LRZ) where Planning Resource is located
- Planning Resource type
- Planning Resource fuel type
- Estimated GVTC MW value
- Estimated completion date of GVTC

- Available form letter can be found here: misoenergy.org / Planning / Resource Adequacy / Resource Adequacy Construct / Related Documents
- New units must have an executed Interconnection Agreement and be registered in the June Commercial Model prior to the upcoming Planning Year at the time of the GVTC Deferral request.
- The MP requesting the GVTC Deferral must post 90 days of credit for the untested ZRCs no later than March 1st prior to the upcoming Planning Year. The credit will be based on the 90 days of daily CONE for the LRZ in which the resource is located.
- MISO will adjust the Market Participant's credit requirements within 10 ten days of the GVTC being submitted into MISO's PowerGADS and has been validated by MISO, or when the MP provides written notification to the Resource Adequacy team that a Planning Resource replacement has been completed.
- If the untested ZRCs are not being used to meet RAR the Market Participant that registered the resource may provide notice to MISO that it wishes to forfeit the deferred GVTC value. MISO will recalculate the resulting Unforced Capacity value and will adjust the credit requirements within 10 days after receiving the notice.
- GVTC or resource replacement must be completed by the last business day of May, whichever is earlier, prior to the upcoming Planning Year. Any GVTC not completed or replaced by the last business day of May prior to the upcoming Planning Year will be subject to the GVTC Deferral Non-Compliance Charge for each day the GVTC or the Planning Resource replacement is not completed.
- The GVTC Deferral Non-Compliance Charge will be based on the sum of the Auction Clearing Price (ACP) and daily CONE based on the LRZ of the Planning Resource, multiplied by the number of ZRCs that have not been tested.
- A GVTC Deferral Non-Compliance Charge for all ZRCS that were cleared in the PRA or used in a FRAP will be assessed to the MP that submitted the GVTC Deferral request and the GVTC or Planning Resource replacement were not completed by the last business day of May prior to the upcoming Planning Year.
- If the actual GVTC MW value is less than the estimated GVTC MW value and the deficient MWs are not replaced, the MP that submitted the GVTC Deferral request will be assessed a daily GVTC Deferral Non-Compliance Charge for the entire Planning Year.

The distribution of GVTC Deferral Non-Compliance Charge will be allocated pro-rata based on each LSE's share of the total Planning Reserve Margin Requirements (PRMR) in MISO.

4.2.3 Intermittent Generation and Dispatchable Intermittent Resources

4.2.3.1 Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements

Intermittent Generation and Dispatchable Intermittent Resources are subclasses of Generation Resource and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1 and the alternate GADS reporting procedure as described below:

Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind (example: run of river or solar) must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours ending 15, 16, and 17 EST from June, July and August. For new resources, or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours ending 15, 16, and 17 EST must be provided prior to participating in the PRA

4.2.3.2 Intermittent Generation Resource - UCAP Determination

The Unforced Capacity for a Capacity Resources that are Intermittent Generation Resources or Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of interconnection service.

Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their annual UCAP determined based on interconnection service volumes and their respect wind capacity credit.

4.2.3.3 Wind Capacity Credit

MISO uses historical wind availability information to calculate Effective Load Carry Capacity (ELCC) to determine a wind capacity credit. MISO's Wind Capacity Credit Report by the LOLEWG reports the wind capacity results for each Planning Year. Appendix A explains the methodology for calculating wind capacity credit. See MISO's website for previous LOLE studies, and starting with the 2013-2014 Planning Year the wind capacity is in a standalone report from the LOLE report which sets the Planning Reserve Margin (PRM).

4.2.3.3.1 Wind Capacity Credit Calculation

MISO calculates specific wind capacity credit for each wind farm and applies it to its registered maximum capability in the Commercial Model or its registered Capacity through the LMR or External Resource registration process. The wind capacity credit MW for the MISO system is allocated to each wind farm based on its capacity value at each of MISO's top 8 highest coincident peaks that occurred during the Summer. The Wind Capacity Credit Report includes analysis and results. This calculation is done on a CPNode basis for wind farms that are registered in MISO's Commercial Model, and on a wind farm basis as submitted through the Planning Resource registration process for External Resources and Behind the Meter Generation. A wind farm that does not have any commercial operation history will receive a wind capacity credit equivalent to the system wide wind capacity credit from the ELCC study, for their initial Planning Year, and thereafter metered data will be used in order to calculate its future wind farm specific wind capacity credit. If no metered data is available, then the wind farm with receive a capacity credit of 0%.

Planning Year	Total System Wind Capacity Credit
2012-2013	14.7%
2013-2014	13.3%
2014-2015	14.1%
2015-2016	14.7%
2016-2017	15.6%

4.2.3.4 Intermittent Generation and Dispatchable Intermittent Resources – Non-wind

For Run of River Hydro, the median hourly integrated net output from the most recent three (3) years up to the most recent fifteen (15) years for hours ending 15, 16, and 17 EST for all days of the Summer (June, July, August) shall be used. If 15 years of historic data is not available for this period when the 15 year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15 year requirement is met.

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

All other Intermittent Generation and Dispatchable Intermittent Resources (e.g. biomass) will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August). Market Participants will need to supply this historical data to MISO by October 31 of each year in order to have their UCAP value determined.

Non-wind powered Intermittent Generation and Dispatchable Intermittent Resources that are new, upgraded or returning from extended outages shall submit all operating data for the prior Summer with a minimum of 30 consecutive days, in order to have their capacity registered with MISO. An example of a qualified extended outage is a resource that does not have a transmission path due to a planned or forced transmission outage.

Resources that experience changing characteristics during the historical period due to changing nameplate capability will have the historical data adjusted by a ratio of the current nameplate rating divided by the nameplate rating in effect at the time the data was collected. For resources that experience partial outages not related to the supply of fuel (e.g. water conditions), regular maintenance, or shutdowns due to safety concerns (e.g. high water), the historical data may be prorated upward to reflect the expected value as if all units had been on line. For units that experience reduced output due to reasons outside of management control data from these periods may be excluded from the calculation of UCAP. MISO will consider reasons outside management control based on the OMC codes entered in GADS for resources that report data. The annual UCAP will be the three year average output value after the adjustments as described above have been made.

An increase in unit capability for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the annual UCAP values have been established will require written notification from the Market Participant to a member of the Resource Adequacy Team in order to update the values. This notification is due by March 1st prior to the Planning Year.

UCAP options for units with derates prior to the GVTC test date are further explained in Appendix J.4.

4.2.3.4.1 Solar Capacity Credit

Solar photovoltaic (PV) resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August). Market Participants will need to supply this historical data to MISO by October 31 of each year in order to have their UCAP value determined. Solar PV resources that are new, upgraded or returning from extended outages shall submit all operating data for the prior Summer with a minimum of 30 consecutive days, in order to have their capacity registered with MISO. Resources with less than 30 days of metered values would receive the class average for the Initial Planning Year.

Planning Year	Total System Solar Capacity Credit
2016-2017	50.0%

4.2.3.5 Intermittent Resource Generation and Dispatchable Intermittent Resources – Must Offer

As described in detail in Section 6.1, an MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan or ZRCs which clear in an annual or Transitional PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unavailable due to a full or partial scheduled outage

The must offer requirement applies to the Installed Capacity of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the UCAP rating. Installed Capacity refers to the amount of cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by (1 – $XEFOR_d$) of the Capacity Resource. Conversely, for wind resources it is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. For non-wind Intermittent Generation and Dispatchable Intermittent Resources, the XEFORd will be set equal to the UCAP divided by the ICAP, where the ICAP shall be the maximum value registered in the Commercial Model. For non-wind Intermittent Resource not modeled in the Commercial Model, the ICAP will be the name plate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by DA close and Forward Reliability Assessment Commitment (FRAC) close of the DA Market close, and FRAC close, will be used to monitor for compliance with the must-offer requirement when the unit's availability is due to non-mechanical and/or non-maintenance reasons. The must-offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast. The same Intermittent Forecast data file used in Day Ahead Must-Offer compliance shall be utilized in FRAC if no further update is provided. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the Installed Capacity as the must-offer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

https://www.misoenergy.org/StakeholderCenter/MarketParticipants/Pages/MarketParticipants.aspx
A header row should be included at the beginning of the file in the format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO's Outage Scheduler (CROW). The must-offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only; and the thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

4.2.4 Use Limited Resources

4.2.4.1 Use Limited Resources – Qualification Requirements

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for a minimum set of consecutive operating Hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- Is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates GVTC and submit the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources are a subclass of Generation Resource and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1.

- MISO will qualify a resource classified as a Diversity Contract as a Use Limited Resource provided the resource meets all of the requirements as an External Resource and the Diversity Contract includes a one MW of summer for one MW of non-summer capacity swap, in order to participate in the Planning Resource Auction (PRA).

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- Use Limited Resources must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- Use Limited Resources with any new or untested additional capacity are eligible for the GVTC Deferral Process as described in Sec. 4.2.2.

4.2.4.2 Use Limited Resources – UCAP Determination

The UCAP value for a Use Limited Resource is based on an evaluation of the type and volume of interconnection service, GVTC value and $XEFOR_d$ value of such Use Limited Resource as described in Appendix H of the RA BPM.

In addition, a Use Limited Resource with contract provisions for guaranteed hours of firm energy will have a decrease in the UCAP calculation to the extent that the guaranteed hours in the contract are less than the required 4 hours across the peak for each day during the Planning Year. There are a total of 1,460 hours (4 hrs/day x 365 days per year) in the Planning Year. Use Limited Resources with run hours less than 1,460 will have their UCAP prorated relative by the percentage of hours of firm energy relative to the 1,460 must offer hours for the Planning Year.

The UCAP methodology is implemented to address the fact that not all Use Limited Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit, based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each Use Limited Resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average $XEFOR_d$ of all the pooled resources, the generating units with better than average availability will reflect higher value than units with below average availability.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4.

4.2.4.3 Use Limited Resources Must-Offer Requirement

As described in detail in Section 6.1 , an MP that commits a Capacity Resource that has ZRCs which clear in an annual or Transitional Planning Resource Auction or used in a Fixed Resource Adequacy Plan must submit the full operable capacity of the Resource, but not less than the ICAP value of ZRCs which either clear the annual or Transitional Planning Resource Auction or used in a Fixed Resource Adequacy Plan, in the Day-Ahead Energy Market and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage.

A Use Limited Resource is required to submit a must-offer into the Day-Ahead Market for at least four (4) continuous hours daily across MISO's forecasted daily peak (including weekends). The must offer period of 4 hours includes the 2 hourly intervals prior to the forecasted peak hour, the peak hourly interval, and 1 hourly interval after the forecasted peak load. This approach enables MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO's peak period will be based on the forecast published one day prior to the operating day in the Market Report provided at the link provided below.

https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx

Under report name, type "look ahead" in the box. A list of summary reports will appear and you can click on the corresponding date.

All outages and derates for Use Limited Resources need to be reflected in MISO's Outage Scheduler (CROW) or SDX. Thresholds for Use Limited Resources will only be applied during the four continuous hours across MISO's peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency.

4.2.5 External Resources

MPs may register an External Resource by providing the information listed below to MISO to qualify such resources as Capacity Resources by registering such resources through the MECT for the upcoming Planning Year. An MP that owns External Resources or contracts for an External Resource via a power purchase agreement (PPA) may also register its External Resources. MP shall notify MISO if the External Resource being registered is an Intermittent Generation or Use Limited Resource. External Resources that are also Use Limited Resources must meet all requirements in section 4.2.4 and be approved by a member of the Resource Adequacy team.

An MP will submit the completed applicable registration form for existing resources via the MECT by February 1st prior to the Planning Year. New External Resource registrations or existing registrations with increased capacity are to be completed in the MECT by March 1st prior to the Planning Year. Existing registrations with increased capacity are still required to submit the original GVTC by October 31st prior to the Planning Year. The registration form will require the MP to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding

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accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it is determined whether or not the External Resource has been accredited, or whether there are any deficiencies.

4.2.5.1 External Balancing Authority Qualification Options

MISO's objective is to ensure that the resources it relies on for its reserve calculations, including External Resource PPAs, will, in fact, be available if called upon in a MISO-declared Emergency. In order to do this, MISO has established host/external Balancing Authority qualification criteria. These criteria apply to Balancing Authorities that impact energy schedules associated with potentially qualifying External Resources. The Balancing Authority qualification criteria ensure that energy schedules corresponding to the qualifying External Resource will only be interrupted in a manner that provides consistency, transparency, and reliability in meriting the objective stated above.

Resources or PPAs that are being submitted to MISO for qualification as an External Resources must have their corresponding energy schedules flow through host/external Balancing Authorities that are in compliance with one of the three options outlined below to qualify.

A PPA executed or external resource owned prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA or ownership of the resource if it is only interruptible as a last resort under Requirement 6.3 of NERC Standard EOP-002. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 6.3 of the NERC Standard EOP-002 between June 1st and September 30th.

A. Scheduled Interruption is Linked to Performance of a Specific Generator in the External Balancing Authority.

In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced planned or outage.

This type of External Resource would be treated similarly to internal generation because those internal resources constitute Capacity Resources, even when they can be interrupted for forced or planned outages. The key to this provision is that the generator delivering the energy in support of the PPA can be specifically identified.

B. Slice-of-System Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures.

PPA or external resource fleets in this category will qualify as Planning Resources so long as the associated capacity schedule only will be curtailed pro-rata along with load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.

Under this situation, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

C. Slice-of-System in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority.

In addition to the slice-of-system treatment noted in category (B), above, slice-of-system PPA or external resource fleet can qualify as External Resources under this category, and MISO and the external Balancing Authority will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met. This qualification category has several requirements for the host Balancing Authority:

1. It must be in MISO's Reliability Coordination Area
2. It must share Operating Reserves with the MISO Balancing Authority
3. It must have a Seams Operating Agreement with MISO containing several features. The Seams Operating Agreement must:
    a. Ensure that the host Balancing Authority has established planning reserve processes and criteria similar to MISO'
    b. Specify the actions that will be taken by both entities – MISO and the host Balancing Authority – during Emergency Procedures prior to implementing Load Shedding
    c. Specify that the host Balancing Authority will submit load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1, provide generator testing data for all resources used to serve firm requirements of the host Balancing Authority, and provide transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

With these requirements in place, when both Balancing Authorities have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

For example, if the load of an external Balancing Authority in capacity emergency is 3,000 MW, and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

4.2.5.2 External Resources - Qualification Requirements

The following information will be required in order to register an External Resource and MPs that register External Resources may receive eligible UCAP provided that the MP:

- Demonstrates that there is firm Transmission Service from the External Resource to the border of MISO's Region, and that;
- Firm Transmission Service has been obtained within MISO to deliver at least the ICAP amount of the Capacity Resource seeking to be qualified from the External Resource(s) to the CPNode within MISO. The CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO's OASIS reservation sinks in for Network Customers, or either;
    - The External Resource has Network Resource Interconnection Service under Attachment X
    - The External Resource was accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date
- External Resources may procure Firm transmission service to meet the deliverability requirements.
    - Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
    - Monthly transmission service requests may be used as long as they cover the entire Planning Year in aggregate and are provided in the MECT.
- Demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program; is available in the event of an Emergency; and performs an annual GVTC test and reports data via GADS.

- External Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- If External Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.
- External Resources greater than or equal to 10 MW based on GVTC must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal. Generation. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs nor does it apply to Intermittent Resources or Intermittent Generation.
- External Resources will be modeled, for PRA purposes, in the LRZ where its firm transmission service crosses the MISO border.
- A PPA must be valid for the entire Planning Year if being used as a Planning Resource. PPAs that do not cover the entire Planning Year will not qualify as a Planning Resource under Module E. If an amended PPA or interim operating plan exists for the Planning Year in which the MP seeks capacity credit, this will be used in calculating the capacity value provided the PPA or interim operating plan contains a capacity amount.
- In order for a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report such information.
- New External Resources must submit GVTC, and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.
- The $XEFOR_d$ for new External Resources in service less than twelve full calendar months will be the class average EFORd for the resource type. An External Resource will use the class average value until 12 consecutive months of data is available and a new Planning Year has occurred.
- All External Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31st in order to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and corrected to the average temperature of the date and times of MISO's coincident Summer peak, measured at or near the generator's location, for the last 5 years, or provide past operational data that meets these

requirements to determine its GVTC and submit its GVTC data to MISO's PowerGADS.

- External Resources undergoing gas conversion are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource's rolling XEFORd.

When to Perform and Submit a Generation Verification Test Capacity (GVTC)

- External Resources that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be met by a real power test or past operational data must be provided during the test period between September 1st and August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC to MISO by March 1st. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a suspended state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time, and must be submitted to MISO no later than March 1st prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT, and must be submitted by March 1st prior to the upcoming Planning Year.
- See Appendix J of this BPM for links to MISO's GVTC Manual and processes.
- External Resources with any new or untested additional capacity are eligible for the GVTC Deferral Process as described in Sec. 4.2.2.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Net Capability Verification Test User Manual, which is located on MISO's website under Planning > Resource Adequacy> Related Documents> PowerGADS Documentation> Power GADS GVTC User Manual.

4.2.5.3 Submission of new External Resources Registrations

A Market Participant must register their new External Resource via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. In order to guarantee new Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Customer Registration team at register@misoenergy.org to become a Market Participant. The information registered in the Registration screen will require the Market Participant to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F contains the information that must be submitted by an MP through the MECT External Resource registration screen. MISO will review the External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for External Resources. MISO will notify the Market Participant within 15 days after the registration form was submitted as to whether or not the resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.5.4 Termination of resources Accredited as External Resources

Because External Resources need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.5.5 Amendments to Accredited External Resource Registration Data

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the deadline.

If a Market Participant needs to modify any of the non-end date information submitted in the registration, which may affect the External Resource's qualification, including, but not limited to, a change in operation or either an increase or decrease in its MW capability, then the Market Participant shall amend registration information in the Registration screen by March 1st prior to a Planning Year in order for MISO to determine whether the resource still qualifies as an External Resource.

4.2.5.6 Renewal of External Resource for Subsequent Planning Years

Each External Resource must be reviewed for accreditation as an External Resource on an annual basis. Renewal of External Resources must be requested by February 1st prior to the Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an

External Resource. MISO will endeavor to notify the Market Participant within 15 days after the renewed registration form was submitted whether or not the External Resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.5.7 Review of Power Purchase Agreements

Market Participants that have entered into power purchase agreement(s) for future Planning Years may request MISO to review the pertinent provisions of the agreements in order to make a preliminary determination of whether the agreement(s) would qualify as External Resources from power purchase agreement(s) as set forth in sections 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered “conforming”. Market Participants must submit a written request for review of such power purchase agreements to the MISO Manager of Resource Adequacy.

MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of their agreements will need to follow the procedures applicable to the planning period for which such External Resource is intended to be relied upon to meet Capacity requirements. This includes the provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.5 in order to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term

An External Resource qualification checklist is posted on MISO’s public website under Planning>Resource Adequacy>Related Documents. This checklist is for informational purposes only and is provided to help Market Participants identify requirements set forth in MISO’s tariff and Business Practices Manuals.

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered "non-conforming" and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;
f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the MISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

4.2.5.8 External Resources – UCAP Determination

External Resources will be accredited at the Capacity Resource's Unforced Capacity based on GVTC value(s), transmission service, and $EFOR_d$ values of such External Resources based on the methodology documented in Appendix H of the RAR BPM. MISO will determine UCAP values for External Resources that are Intermittent Generation as described in Section 4.2.3. External Resources, from PPAs, with varying monthly Capacity values will be credited with lowest monthly Capacity value of the contract.

4.2.5.9 UCAP Determination – Full Requirements PPA

Market Participants may register External Resources to model a full requirements power purchase agreements with a counterparty. This designation will be made in the MECT tool on the External Resource registration. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource's UCAP and Must Offer calculations beginning with the 2014-2015 Planning Year.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left(\frac{ICAP_i\ x\ (1 + PRM_{LRZ})\ x\ (1 + TL_{LBA})}{(1 - XEFORd_i)} \right)$$

Where:
$ICAP_{adjusted}$: PPA Pct. x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
PRM_{LRZ}: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in.
TL_{LBA}: Transmission Losses for the LBA that the External Resource will be serving load in.

4.2.5.10 External Resources – Must Offer Obligation

As described in detail in Section 6.1, the maximum must offer requirement applies to the registered Capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan or clear in either an annual or Transitional PRA s must submit the full operable capacity of the Resource, but not less than the ICAP value of registered Capacity and make an Offer into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage. The must-offer requirement applies to the Installed Capacity (ICAP) of an External Resource, and not the UCAP rating. Installed Capacity refers to the amount of ZRCs divided by (1-XEFORd) of the Capacity Resource. The must offer requirement will be capped at the resource's ICAP value.

An MP that has ZRCs from External Resource(s) that are either indicated in a Fixed Resource Adequacy Plan or clear in an annual or Transitional Planning Resource Auction establishes a Must-Offer requirement. Offers in the Day-Ahead Energy Market can only be Normal Energy type with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Reliability Assessment Commitment (FRAC).

Therefore, the must-offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via EOP-002.

The MP that has either identified ZRCs from a FRAP or cleared ZRCs in an annual or Transitional Planning Resource Auction from External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator via System Data Exchange (SDX) or CROW. External Resources must be available to schedule Energy into MISO's Region during emergencies if needed by MISO. EOP-002 includes a mechanism to schedule all External Resources into MISO's BAA. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR". The NERC IDC (Interchange Distribution Calculator) name of the Planning Resource must be entered in the value field of the MISC section exactly as it appears in the approved registration in the MECT, Outage Scheduler (CROW) or SDX, except that the name must be in all caps. The NERC IDC name in the External Resource registration should be provided in the correct format in order for MISO to retrieve outage information from the SDX.

External Resources that are Use Limited Resources must follow the Day-Ahead must-offer requirements for Use Limited Resources as documented in Section 4.2.4.2 of this BPM.

Compliance with "must offer" requirements will be evaluated by MISO on a nondiscriminatory basis. MISO will analyze the compliance with must-offers in both the Day-Ahead and RAC by taking into account information provided by MISO's Outage Scheduler (CROW), NERC SDX and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation.

4.2.6 DRR Type I and Type II – Qualification Requirements

Demand Response Resources (DRR) Type I and Type II may qualify as Capacity Resources provided that (All references to generation availability and testing in this section pertain to DRRs backed by generation.):

- DRR Type I and Type II (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into the PowerGADS tool through the Market Portal.
- DRR Type I and Type II must demonstrate capability on an annual basis. Verification of DRR Type I and Type II capability will be in accordance with the guidelines

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established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.

- DRRs may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1.
- DRRs must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- DRRs with any new or untested additional capacity are eligible for the GVTC Deferral Process as described in Sec. 4.2.2.

4.2.6.1 DRR Type I and Type II – UCAP Determination

MISO will determine the UCAP value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and $XEFOR_d$ values of such generator. If such behind the meter generation facility is interconnected to the Transmission System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average $EFOR_d$ of the resource type will be used to calculate the forced outage rate.

A $XEFOR_d$ value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

UCAP MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4.

4.2.6.2 DRR TYPE I AND TYPE II – Must Offer

As described in detail in Section 6.1, an MP that commits a Generation Resource's UCAP MW must submit the full operable capacity of the Resource, but not less than the ICAP value of ZRCs cleared and/or used in a Fixed Resource Adequacy Plan, into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage.

This same must offer requirement applies to the Installed Capacity of DRR Type I and Type II, (and not the UCAP rating) used to meet Resource Adequacy Requirements. Installed Capacity refers to the amount of ZRCs cleared in an annual or Transitional PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – $XEFOR_d$) of the Capacity Resource.

4.2.7 Load Modifying Resource Obligations and Penalties

Load Modifying Resources (LMRs) consist of Demand Resources (DR) and Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Control Load Management and other resources that result in additional and verifiable reductions in end-use customer demand during an Emergency.

Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a load CPNode. BTMG is not included in MISO's Setpoint Instructions. An LMR that relies solely on a generator to reduce load or as a fallback for load control or interruption must register as a BTMG.

BTMG and DR requirements to qualify as a LMR are covered in Sections 4.2.8 and 4.2.9 of this BPM.

LMRs differ from Capacity Resources in that they do not have a must offer requirement, however they must be available for use with MISO as defined in this BPM during Emergency events (including capacity and transmission events) declared by MISO unless unavailable as a result of maintenance, Force Majeure or other reasons outlined in this BPM. LMRs communicate to MISO their availability through the MISO Communications System (MCS). MPs with multiple LMR assets must provide updates to availability specific to each LMR that is listed in the MCS. It is critical that LMR availability be current at all times as the Scheduling Instructions (dispatch directives) and ultimately performance and availability review will utilize the information in the MCS at the time the Scheduling Instruction is given. If the LMR is on any type of outage, the LMR availability should be adjusted by decrementing LMR availability in the MCS by reducing the "MWs Avail for MISO" for the affected LMR. If a LMR is scheduled to be deployed by the MP, the "Self Sched LMR MW" section in the MCS should be increased for LMR MWs that are scheduled to be deployed and the "MWs Avail for MISO" amount should be reduced to reflect the remaining MWs available for MISO deployment. For specifics on MCS functionality, please see the MCS User's Guide located in the MCS.

If an Emergency is declared by MISO that requires LMR deployment, MISO will create Scheduling Instructions in the MCS using the LMR availability information ("MWs Avail for MISO" and "Self Sched LMR MW") provided by MPs. The LBA and the MP will receive a notification of the Scheduling Instructions via a MCS message. The MP will need to acknowledge receipt of the Scheduling Instruction and update the remaining availability, if any, of the LMR(s) being used to meet the Scheduling Instruction in MCS to reflect the MW amount

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available in the specified time(s). This update and acknowledgement should be done within one hour of receiving the Scheduling Instruction from MISO. Also, before the Emergency deployment, the MP that registered the LMR(s) should submit the breakdown of LMRs and associated MWs used to meet the total MWs contained in the Scheduling Instruction via the LMR Advance Reporting page in the MCS.

MPs that report LMR availability (including self-scheduled MWs) in the MCS that is less than the performance obligation based on the MW value that is being used to meet RAR, may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declared an Emergency. Meter data for the LMRs used to meet the MWs requested in the Scheduling Instruction should be uploaded in the Demand Response Tool within 53 days of the Emergency event or as requested by MISO.

A LMR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period and has indicated "0" MWs Avail for MISO and "0" Self Sched LMR MWs in the MCS or the resource has reached its registered number of deployments).

4.2.7.1 LMRs with Dual Registration

LMRs have the opportunity to register as other market mechanisms, namely Emergency Demand Resources and Demand Response Resources.

LMRs that have some capability registered as Emergency Demand Response (EDR) or Demand Response Resource (DRR) should adjust their availability in MCS to reflect net LMR MWs available to MISO (e.g. decrement total LMR capability by EDR offer amount and DRR cleared Day Ahead or pending Real Time offer).

4.2.7.1.1 LMRs Also Registered as Demand Response Resource (DRR)

DRR Type I and Type II that have converted UCAP to ZRCs which were used to meet Resource Adequacy Requirements (RAR) are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert all of its associated UCAP may also register the remaining UCAP of the resource as an LMR. In this case, the UCAP converted and used to meet Resource Adequacy Requirements under the LMR designation would follow the respective LMR requirements and likewise the DRR UCAP if converted and used to meet RAR would carry the must offer requirement. The combined UCAP converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned UCAP value of the singular resource.

4.2.7.1.2 LMRs Also Registered as an Emergency Demand Resource (EDR)

An LMR is not required to be a Network Resource. A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 regardless of whether it qualifies as an LMR under Module E-1. An LMR may also dual register and qualify as an EDR. In the case of a dual LMR / EDR registration, the resource will be dispatched as an EDR when there is a pending EDR offer (EDR offers are made on a daily basis). While the resource is dispatched as an EDR, it maintains its LMR obligations and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered. MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff.

4.2.7.2 LMR Performance Obligations

The registered capacity of accredited LMRs that has been converted to ZRCs and has cleared in the PRA must be available as outlined above for use in the event of an Emergency declared by MISO. Market Participant utilizing LMRs to meet Resource Adequacy Requirements will be subject to the penalties described in Section 69A.3.9 of the Tariff if the LMR fails to respond in an amount greater than or equal to the target level of a Load reduction (or registered firm service level) for DR or target level of generation increase for a BTMG as indicated on their Dispatch Actual Screen to meet the total MWs contained in their Scheduling Instruction. This "target" level is indicated by the MP via the MCS' "Dispatch Actual Screen" which outlines which LMRs were utilized and the associated MW levels to meet the total MWs contained in their Scheduling Instruction. Such LSE shall be assessed the costs that were otherwise incurred to replace the energy deficiency at the time the LMR was dispatched.

DR that registers as firm service level must reduce to the MW number included in their registration anytime the resource is used to meet a Scheduling Instruction. The MW value assigned toward meeting the Scheduling Instruction from a firm service level DR is the forecasted Load minus the firm service level at the time of the Emergency deployment and as indicated by the MP in the MCS.

MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. LMR values entered in the MCS (availability) will also be considered when evaluating whether target levels of generation increase or Load reduction have been met.

The operators of LMRs that properly report to MISO that an LMR is unavailable in the MCS prior to receiving a Scheduling Instruction or the LMR does not respond to the Transmission Provider's dispatch instruction will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction for DR or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) and properly reflected in the hourly availability in the MCS for each resource. Likewise, for certain LMRs that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted and the hourly availability in the MCS should be updated to properly reflect the anticipated capability of the resource.

4.2.8 BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Confirming through the registration process such BTMG can be available to provide energy with no more than 12 Hours advance notice from MISO or the LBA and sustain energy production for a minimum of four (4) consecutive Hours for 5 emergency events.
- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times as needed during the Summer season by MISO or the LBA for emergency event purposes during the Planning Year.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce energy may qualify in meeting this requirement if located in the same LRZ).
- Behind the Meter Generation must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- Behind the Meter Generation with any new or untested additional capacity are eligible for the GVTC Deferral Process as described in Sec. 4.2.2.

- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource has to submit information in accordance with Section 4.2.3.

- For wind resources being registered as BTMG, the following information is required:
  - Resources with at least one year of metered values would submit metered values in MWs for all Hours in the test period.
  - Resources with less than one year of metered values would receive class average for the Initial Planning Year.
- For solar resources being registered as BTMG, the following information is required:
  - Resources with at least 30 consecutive days of metered values would submit metered values in MWs for all hours in the test period.
  - Resources with less than 30 days of metered values would receive class average for the Initial Planning Year.

Internal purchase power agreements (PPAs) will not be qualified by MISO.

- BTMGs that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- If BTMGs used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.

4.2.8.1 Submission of New BTMG Registrations

A MP will register its new BTMG via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. The registering entity must be a MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.org to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E contains the information that must be submitted by an MP through the MECT LMR registration screen. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to notify the MP within 15 days after the registration form was submitted regarding whether or not the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.8.2 Termination of BTMG Accredited as LMR

Because BTMGs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.8.3 Amendments to Accredited BTMG Registration Data

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG's qualification, including, but not limited to, a change in operation or has either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1st prior to a Planning Year in order for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1st.

Renewal of BTMG for subsequent Planning Years

BTMG must be reviewed for accreditation as an LMR on an annual basis. A MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested by February 1sr prior to the Planning Year. NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3, in order to have UCAP values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to review the registration for approval within 15 days after the revised registration form was submitted to determine whether or not the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.8.4 Behind the Meter Generation (BTMG) – UCAP Determination

The UCAP value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, and $XEFOR_d$ value of such BTMG. Since a BTMG causes a reduction in demand visible to MISO, UCAP is adjusted upward by applying the transmission loss percentage for the LBA to the capacity rating.

The Unforced Capacity methodology is implemented to address the fact that not all BTMG contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit, based on its $XEFOR_d$, UCAP provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy.

BTMG that are intermittent resources will have their UCAP determined consistent with the methodology described for similar resource fuel types as described in Section 4.2.3.2 through 4.2.3.4.

4.2.8.5 BTMG Deliverability

BTMG must be deliverable to Load located within MISO's Region using one of the following:

- BTMG that is located in the same LBA as the LSE's CPD forecast that is being used to offset the same LSE's PRMR in the same LBA.
- Market Participant has obtained firm transmission service from the BTMG to its load.
- BTMG may be used by any Network Customer within the LBA in which the BTMG is located provided that the Network Customer identifies the BTMG as a Network Resource on MISO's OASIS.
- Network Contract Numbers cannot be used, the Transmission Service Request must either be Firm Point to Point or Firm Network Designated.
- The load is a network customer and the BTMG has been determined to be aggregate deliverable by acquiring Network Resource Interconnection Service or as determined by the Market Transition Deliverability test provided that the BTMG is interconnected to MISO's Transmission System.
- BTMGs that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.

4.2.8.6 Measurement and Verification of BTMG

See Attachment TT of the Tariff.

4.2.9 Demand Resource – Qualification Requirements

MPs with DR can qualify the DR as an LMR by:

- Registering the reduction capability of the DR, excluding transmission losses and consistent with conditions at MISO's Coincident Peak.
- Confirming through the registration process such DR can be available to reduce Demand with no more than twelve (12) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the DR is not dependent on the dispatch of a BTMG owned or operated by a wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resources within an LBA that can reduce Demand may qualify in meeting this requirement).
- Confirming through the registration process that the DR is capable of being interrupted at least the first (5) times during the Summer season as needed by MISO or the LBA for Emergency purposes during the Planning Year.
- Confirming that the Market Participant has the authority to reduce demand using the DR.
- Documenting in the MECT the DR's capability to reduce demand to a targeted Demand reduction level or firm service level at the MISO Coincident Peak. All DR owners should provide a procedure document detailing the steps followed to implement the demand reduction in addition to one of the following options:
    - Provide documentation from the state that has jurisdiction accrediting the DR program. Additionally, if not specified in the state documentation, provide documentation supporting the capacity of the DR being registered.
    - Verification from a third party auditor that is unaffiliated with the MP that documents the DR's ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.
    - Provide past performance data from the previous Planning Year that demonstrates the DR's ability to reduce to the targeted Demand reduction level or firm service level. The performance data can be from a MISO called event or a self-scheduled implementation.
    - If past performance data does not exist from the previous Planning Year, then a mock test can be provided. The mock test should show:
        - The demand resource's meter data from the previous planning year's summer months. New resources can provide documentation supporting estimated demand levels for the summer months.

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- Documentation showing a mock execution or drill of implementing the demand resource without actually implementing the demand reduction.

  - Beginning in Planning Year 2014-2015 and thereafter, test, performance data, third party audit or documentation supporting the MW being registered should be from September 1 to August 31st immediately preceding the applicable Planning Year. Results should be submitted to MISO by October 31st.

- Documenting in the MECT the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 69A.3.9 of the Tariff. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE's load to weather. An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69A.3.5 of the Tariff.
- DR that has been retired prior to the Planning Year will not qualify as a Planning Resource.
- If DR used to meet Resource Adequacy Requirements obligations retires or suspends during the Planning Year, they must be replaced effective with their change of status date.

4.2.9.1 Demand Resource Registration Process

DR can be registered to be used as a Planning Resource and receive UCAP MW that can be converted to ZRCs.

Submission of new DR Registrations

A MP may register new DR via the LMR Registration screen in the MECT by March 1st prior to the Planning Year. In order to guarantee new Planning Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. The registering entity must be a MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, should contact the Customer Registration team at register@misoenergy.org to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D contains the information that must be submitted by an MP through the MECT LMR registration screen for DR. MISO will review the DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to review the registration within 15 days after the registration was submitted to determine whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

4.2.9.2 Termination of Demand Resource Accredited as LMR

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

4.2.9.3 Amendments to Accredited DR Registration Data

The Market Participant can amend the registration for a DR for an existing upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The MP may modify any of the non-end date information submitted in the registration, which may affect the DR's qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit registration information in the MECT registration screen by March 1st prior to the Planning Year in order for MISO to determine whether the resource still qualifies as an LMR.

4.2.8.4 Renewal of DR for subsequent Planning Years

A DR must be reviewed for accreditation as an LMR on an annual basis. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT registration screens. Renewal of DR must be requested by February 1st prior to the Planning Year. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to notify the MP within 15 days after the renewed registration form was submitted regarding whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

4.2.8.5 Demand Resources – UCAP Determination

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the Planning Year. Capacity values for Demand Resources will be based on documentation from the state, third party auditor, past performance, or mock test consistent with their ability at MISO's Coincident Peak Demand. Since DR is a reduction in demand, UCAP is adjusted upward by applying the MISO PRM and transmission loss percentage for the LBA to the capacity rating.

MISO will determine through the registration process whether the BTMG or DR qualifies as an LMR. Once the LMR and its MWs are entered into the MECT and accredited by MISO, then the MP that registered the LMR can elect to convert all or part of the LMR's accredited MWs into ZRCs. BTMG or DR formally become an LMR if approved by MISO and are used to meet Resource Adequacy Requirements.

The resource may also qualify as an EDR under Schedule 30 regardless of whether it qualifies as an LMR. Dual registration as an EDR and an LMR is acceptable

4.2.8.6 Demand Resource Deliverability

The owner of ZRCs converted from DR may use them as part of a FRAP or, offer them into the PRA. The DR ZRCs are considered deliverable regardless of the LRZ where the DR physically resides.

4.2.8.7 Measurement and Verification of Demand Resource

See Attachment TT of the Tariff.

4.2.9 Energy Efficiency Resources

Energy Efficiency (EE) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecast used for the Planning Resource Auction for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric energy consumption due to existing EE programs that is reflected in the CPD forecast cannot also be qualified as an EE Resource.

All of the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed in the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for the Planning Year. The Nominated EE Value is the expected average demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days from June 1 through August 31, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource no later than 30 days prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource no later than 30 days prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report prior to a subsequent Planning Year or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to measure PRA commitment compliance during the Planning Year. Details regarding PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE

Value that is used to measure PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in PRAs or used in a FRAP for that Planning Year and three subsequent Planning Years. For example, an Energy Efficiency resource installed and qualified prior to June 1, 2013, could participate in the PRA or be used in a FRAP for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the Energy Efficiency resource registers and meets the qualification requirements for each Planning Year. After four years, the Energy Efficiency resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the demand forecast.

4.2.9.1 Energy Efficiency Resource – M&V

See Attachment UU of the Tariff.

4.3 Confirmation and Conversion of UCAP MW

To create a ZRC, a MP must confirm the UCAP MW and then convert UCAP MW from each qualified Planning Resource to ZRCs through the MECT UCAP/ZRC conversion screen. UCAP confirmation and conversion must be completed prior to the opening of the PRA auction window. A ZRC represents 1 MW-day of qualified Unforced Capacity from a Planning Resource for a specific Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. All types of Planning Resources are tracked in the MECT, which tracks Module E-1 resources used to meet Resource Adequacy Requirements.

When ZRCs are converted from UCAP by the Asset Owner, the ZRCs are populated into the available ZRC account for that Asset Owner. MISO will keep track of how many ZRCs the MP has created, and how many remaining UCAP MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the specific Planning Resources that they were created from in order to assist with establishing clearing requirements, the auction clearing process and market mitigation monitoring.

4.4 ZRC Transactions

4.4.1 Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the 'ZRC Transactions' tab in the MECT. Both the 'Buyer' and 'Seller' are required to account for a ZRC transaction in the MECT, the 'Seller' is required to submit the transaction in the MECT, and the 'Buyer' is required to confirm the transaction reported. Once the transaction has been submitted and confirmed by both parties, the ZRC transaction volumes will be subtracted from the seller's available ZRC account and added to the buyer's available ZRC account. The MECT allows transactions based on type of ZRCs.

5 Resource Adequacy Requirements

5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resources Zone (LRZ) to meet the MISO footprint's Planning Reserve Margin Requirement (PRMR). An LSE can meet its PRMR by any of the following ways:

1) Self-scheduling
2) Fixed Resource Adequacy Plan (FRAP)
3) Participating in the Planning Resource Auction (PRA)
4) Paying the Capacity Deficiency Charge (CDC)

5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of the Local Resource Zones no later than September 1st of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region, based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

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Attachment 2 for Response to HMPL 2-43
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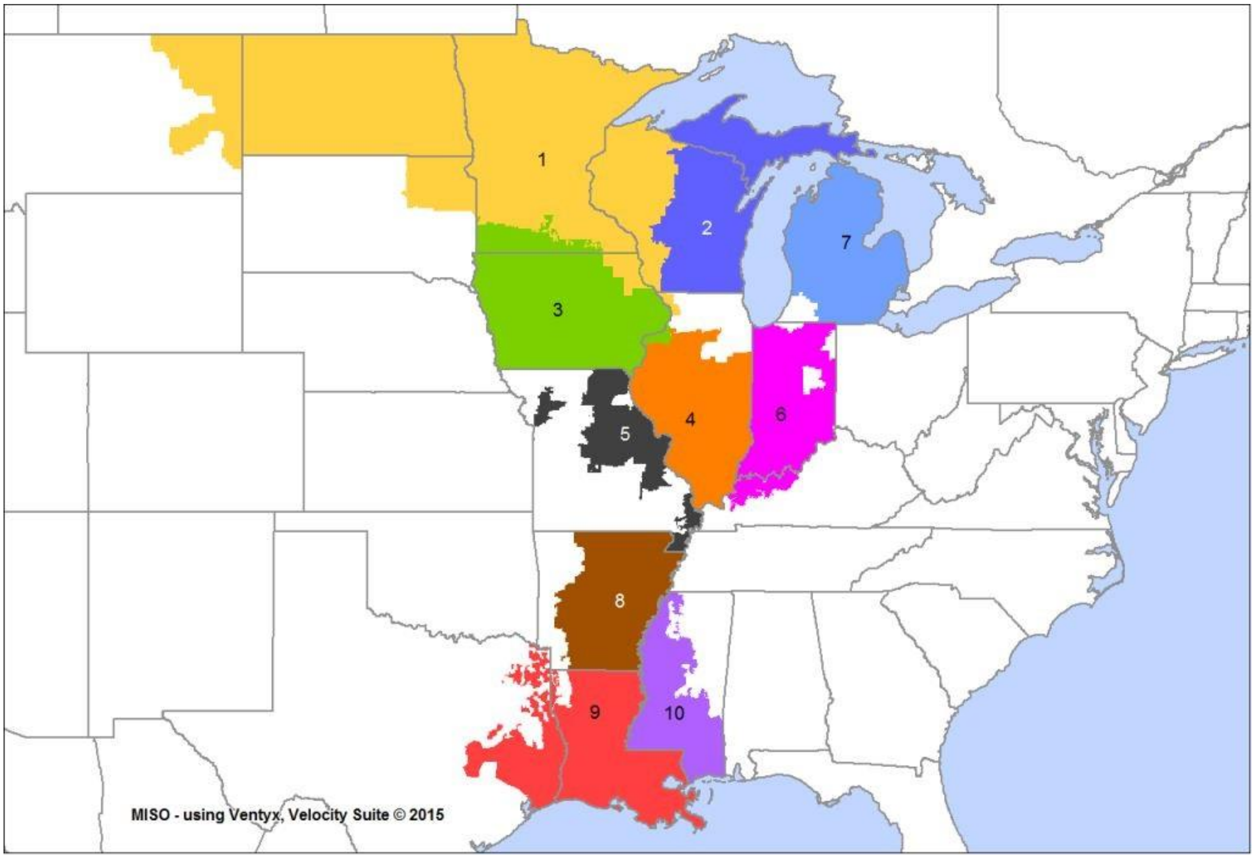
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MISO - using Ventyx, Velocity Suite © 2015

5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV, may change the configuration of the LRZs if a reevaluation trigger has occurred and after consideration of the criteria outlined for consideration in setting LRZ boundaries. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA. MISO will share any reevaluation triggers and the results of the analysis documenting the impacts of the proposed LRZ boundary changes with stakeholders in an open and transparent manner prior to making any filings to change LRZ boundaries.

Once the boundaries of an LRZ have changed, its boundaries should stay constant for at least three years to provide stable future locational signals.

5.2.1.1 Re-evaluation Triggers

The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region. Such changes are called re-evaluation triggers, and they include but are not limited to the following:

1) Significant changes in membership:
   Reevaluation may occur for LRZs where new members join the MISO system or for areas which neighbor the regions where new members join the system. Reevaluation may occur prior to or in the cycle immediately following the integration of new members into the MISO system.
2) Significant changes in the Transmission System:
   Transmission must be on target to be in-service by June 1 of the year which would follow a filing for a LRZ boundary changes (i.e., the transmission must be in-service for the first summer where the zonal changes will go into effect). The changes to the transmission system should impact transmission constraints represented in the MISO Resource Adequacy construct for the zone(s) being reevaluated.
3) Significant changes in Resources:
   Changes to the resource mix may include the addition of significant new generation or the retirement of significant existing generation. The resource changes should be shown to modify the transmission system flows in the zone(s) being studied, impacting transmission constraints represented in the MISO Resource Adequacy construct.

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The existence of a trigger will not guarantee that a zonal change will be implemented; the trigger will allow the analysis to proceed and will be considered as part of the final decision on whether or not to change zonal boundaries.

5.2.1.2 Re-evaluation Considerations

Once a re-evaluation trigger has been met, the geographic boundaries of the zone or zones may be re-evaluated. This re-evaluation will be based upon an analysis that considers the following factors.

1) Electrical Boundaries of Local Balancing Authorities
2) State boundaries
3) Relative strength of transmission interconnection between Local Balancing Authorities
4) Results of LOLE studies
5) Relative Size of LRZs
6) Natural geographic boundaries such as lakes and rivers

The electric boundaries of Local Balancing Authorities, state boundaries, and natural geographic boundaries will be considered by inspection. Additional information on the process used to analyze the other criteria is below.

Relative Strength of Transmission Interconnections between Local Balancing Authorities
Multiple aspects of the transmission system are considered in this portion of the evaluation. These aspects are first investigated individually and then the final assessment considers all of the factors. The assessment includes the following:

- Previously identified LOLE results (Capacity Import and Export Limit constraints)
- Constraint variation
- Transmission projects
- Physical ties including post-contingency connectivity and transmission service

LOLE results identified for Capacity Import and Export Limit analysis before and after the boundary change is applied will be considered. Zonal transfer analysis yields a list of constraints. The most limiting constraint after redispatch determines a zone's limit in the LOLE study. In the reevaluation analysis, the less limiting constraints are also considered since reconfigurations impact the transfer level at which constraints are limiting. Also, while there can only be one limiting constraint, multiple constraints can be seen at similar transfer levels. For example, assume the most limiting constraint is at a transfer level of 100 MW. There are two constraints at 99 MW and one at 90 MW. Since these transfer levels are very close, all four are considered in this evaluation.

Constraint variation is caused by reconfiguration of Local Resource Zones. This variation is caused by changing the generation that is used to create the transfer. Zonal definitions determine which generators are used in the transfer analysis so any change in zonal definition may result in a difference in the impact the transfer has on the constraint. It is possible that a constraint has an impact above the threshold before reconfiguration and less than the threshold afterwards which is considered in this evaluation.

The impact of approved MTEP Appendix A and Target A transmission projects is considered. If a project mitigates a constraint and the project is expected to be in service prior to the Planning Year under consideration, then the impact of the transmission project to the LOLE results is considered.

MISO will consider the number of ties of any reconfigured zone. Generally, a reconfigured zone should have two or more ties with the rest of MISO. Two or more ties between the zones are optimal when planning for contingencies so the zones are still connected post-contingency. Any LBA being added to an existing LRZ should have two or more ties with an LBA in the new LRZ. Any other impacted LRZs should have contiguous LBAs with two or more ties. Further consideration is needed if an LBA leaving an LRZ results in an LRZ with unconnected LBAs. In addition, confirmed transmission service between zones may be considered when evaluating reconfigurations. Confirmed long-term transmission service indicates transmission capacity between the zones has been previously evaluated.

The Results of LOLE Studies

LOLE studies will be performed with the LRZ configuration being considered. The results of this analysis will be compared with the prevailing LRZ configuration. This LOLE analysis includes a MISO PRM model analysis (Section 3.5), LRZ LRR determination (Section 5.2.2.2), and capacity import and export limit analysis (Section 5.2.2.1) for the LRZ configuration being considered and for the prevailing LRZ configuration. The results of this analysis and comparison with the prevailing system results will be used as one factor in determining whether LRZ changes are warranted, in conjunction with the other LRZ considerations.

Relative size of LRZs

The relative size of an LRZ will contain no less than 2,000 MW of demand.

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5.2.1.3 Determination of LRZ Boundaries

Following the determination of an LRZ trigger, the conclusion of all analysis with consideration of stakeholder feedback will determine whether the LRZ boundaries will be changed. This determination will be based upon the benefits and/or risks that the LRZ boundary changes would present on the system. MISO's final determination will be shared with stakeholders and the changes will be filed with FERC.

5.2.1.4 Establishing Sub-Regional Resource Zones (SRRZ)

MISO will also establish SRRZs applicable for each Planning Year. A SRRZ is a zone, comprised of a LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Currently, MISO has two SRRZs: MISO South defined as LRZs 8,9, and 10 and MISO Midwest defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, SPP, and the other Joint Parties. This agreement established Regional Directional Transfer Limits (RDTL) that limit the amount of total transfer between these two SRRZs in the PRA. The RTDL from South to Midwest is 2,500 MW and the RTDL from the Midwest to South is 3,000 MW.

MISO shall establish the Sub-Regional Export Constraint (SREC) and Sub-Regional Import Constraint (SRIC) by March 1st prior to the Planning Year. The methodology for determining the SREC and SRIC for each SRRZ is described below.

5.2.1.4.1 Determination of SREC and SRIC

The following steps describe the steps MISO will utilize to calculate the SREC and SRIC.

1. Begin with the Regional Directional Transfer Limits between the two SRRZs
2. Complete a feasibility analysis to review operational events from previous Summer peak to determine if a further reduction to the Regional Directional Transfer Limit is warranted for reliability.
3. Decrement the initial RDTL (from step 1) based upon completed feasibility analysis
4. Subtract from the net RDTL (from step 3) the sum of Firm Reservations on MISO OASIS that utilize the contract path between South and Midwest and are exporting the MISO BA for the Planning Year. This difference determines the SREC and SRIC to be utilized for the Planning Year.

Example from the 2016-2017 Planning Year

1. The RTDL from South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
2. MISO's feasibility analysis for the 2016-2017 Planning Year determined that no additional reduction of the RTDL was required; 0 MW.
3. The net RTDL for 2016-2017 is equal to the initial RTDL; South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
4. The MISO OASIS Reservations, in each direction, that exported the MISO BA for the 2016-2017 were summed:
   South to Midwest Direction: 1,624 MW
   Midwest to South Direction: 206 MW

Final SREC and SRIC applied for the 2016-2017 Planning Year:

South SRRZ SREC: 876 MW
South SRRZ SRIC: 2,794 MW
North SRRZ SREC: 2,794 MW
North SRRZ SRIC: 876 MW

5.2.1.4.2 Regional Directional Transfer Limit Feasibility Analysis

On an annual basis, prior to administrating the PRA, MISO will review operational data from the previous Summer peak season to determine if operational events experienced in the past and forecasted expected conditions for the Planning Year warrant a reduction in the initial RTDL between the MISO South and Midwest Regions.

The following data sources are considered for the feasibility analysis:

– Studies that assess MISO transfer capability between Regions
– Studies that assess load diversity between Balancing Authorities
– Transmission system constraints
– Congestion history on relevant transmission constraints
– Capacity or Transmission Emergency alerts, warnings, or events

5.2.2 Local Requirements and Transfer Capability

5.2.2.1 Calculation of Transfer Limits of the Local Resource Zone

MISO will determine the Capacity Import and Export Limits for each Local Resource Zone (LRZ) by performing a transfer analysis study. The Capacity Import Limit (CIL) impacts the calculation of the Local Clearing Requirement (LCR) for each LRZ. Capacity Export Limit (CEL) and CIL are applied as limits in the Planning Resource Auction clearing process.

Transfer analysis will be performed on up to three scenarios that will include the Planning Year. The two additional scenarios will depend on study needs, in general the MTEP 5 and 10 year study scenarios may be considered. Potential drivers of study needs might include:

- Regulations (passed or anticipated)
- System changes (generation or transmission)
- Stakeholder needs

Transfer Analysis

Transfer capability is the measure of the ability of interconnected power systems to reliably transfer power from one area to another under certain system conditions. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. Total Transfer Capability (TTC) indicates the total amount of power able to be transferred before a constraint is identified. TTC is the base power transfer plus the incremental transfer capability.

$$Total\ Transfer\ Capability\ (TTC) = Base\ Power\ Transfer + \ FCITC$$

Linear FCITC analysis will identify limiting constraints with a minimum Distribution Factor (DF) cutoff of 3%, meaning the transfer and contingency must increase the loading on the overloaded element by 3% or more. In addition facilities must have loadings 100% or more of the normal rating for NERC Category A contingencies and loadings 100% or more of the emergency rating for Category B contingencies.

Export and import capabilities of subsystems will be respected and machine limits are enforced. Exporting LRZs available capacity will include offline units. A pro-rata dispatch is used which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base dispatch from its maximum dispatch, which reflects the available capacity of the unit. Refer to Table 2 and the equation below for an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Max dispatch – Unit Dispatch)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 2: Example Subsystem

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

General Assumptions

Power flow models and input files are required to determine the import and export limits of each LRZ. Input files (subsystem and contingency) from MTEP studies built for timeframes matching the effective period of the transfer limit study will be used. Single-element contingencies in MISO and seam areas are evaluated in addition to submitted files.

Subsystem files will be modified to include required source and sink definitions, details are provided in the next two sections (Import and Export Limit Determination Sections). The monitored file will include all facilities under MISO functional control and Seam facilities 100 kV and above.

Power flow models will contain approved MISO MTEP Appendix A and Target A projects with effective dates on or before the effective date of the study model. The following generators are excluded from transfer analysis dispatch:

- Nuclear
- Generators with negative dispatch parameter
- Must run
- Self-scheduled
- Hydro
- Wind

Wind will be ramped down for transfers and will not be ramped up. Maximum wind output will be limited to base dispatch in the power flow model which is set by the wind capacity credit. MISO and external area interchange in the base case will be set to the net firm transmission service reservation level.

Import Limit Determination

To determine an LRZ's limits, a generation to generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) while decreasing generation inside the LRZ under study. LBAs that are interconnected with the LRZ under study are considered adjacent. Tiers are used to define the generation pool used for import studies and are comprised of the adjacent systems of the zone being studied.

- Tier 1 – Generation in the MISO LBAs adjacent to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO LBAs adjacent to Tier 1

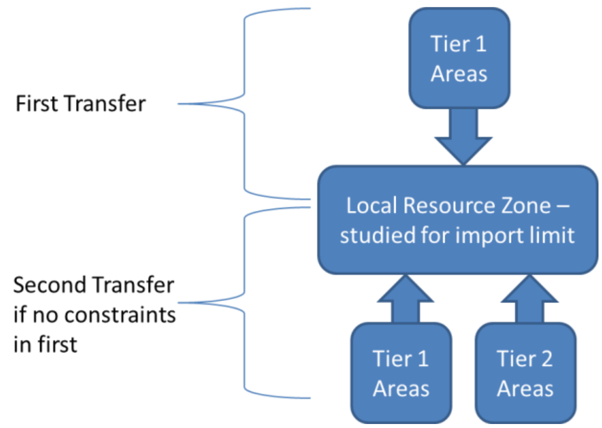

Figure 5.1: Tiered import illustration

Import limit studies are analyzed first using Tier 1 generation only. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the limit is the adjusted available capacity in Tier 1 plus any base import or minus any base export. Available capacity must be adjusted to account for changes due to redispatch. If a constraint is not identified using Tier 1 generation only, Tier 2 generation is then considered using the same redispatch process. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone's import limit.

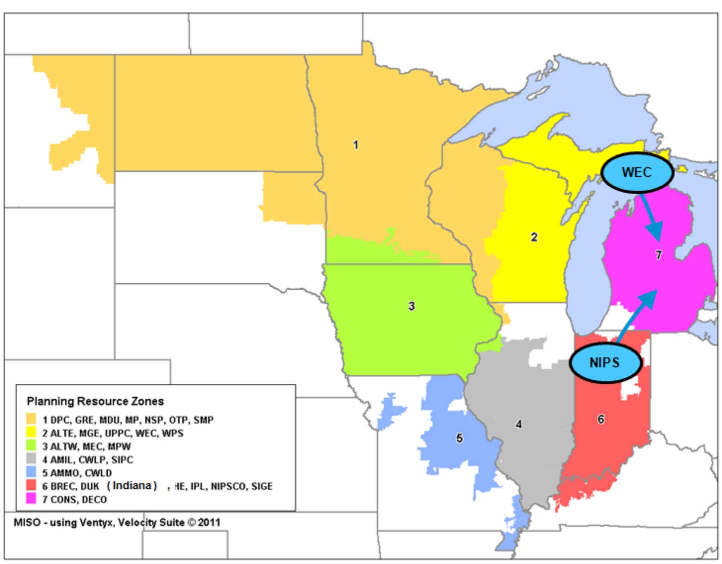

Figure 5.2: Example - MISO LBAs Used for First Test of LRZ 7 CIL

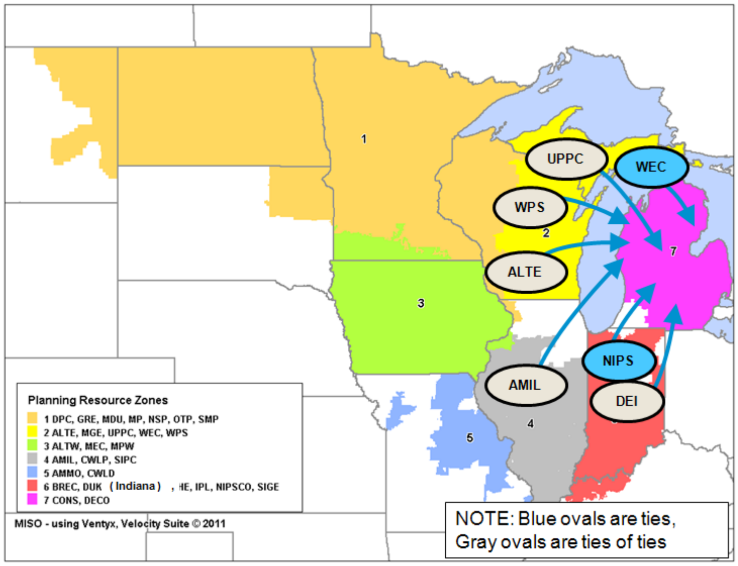

Figure 5.3: Example - MISO LBAs Used for Second Test of LRZ 7 CIL

Export Limit Determination

To determine the CEL for an LRZ, the source subsystem is under study. Generation within the LBAs contained in that particular LRZ is increased while generation in all other MISO LBAs is decreased proportionately.

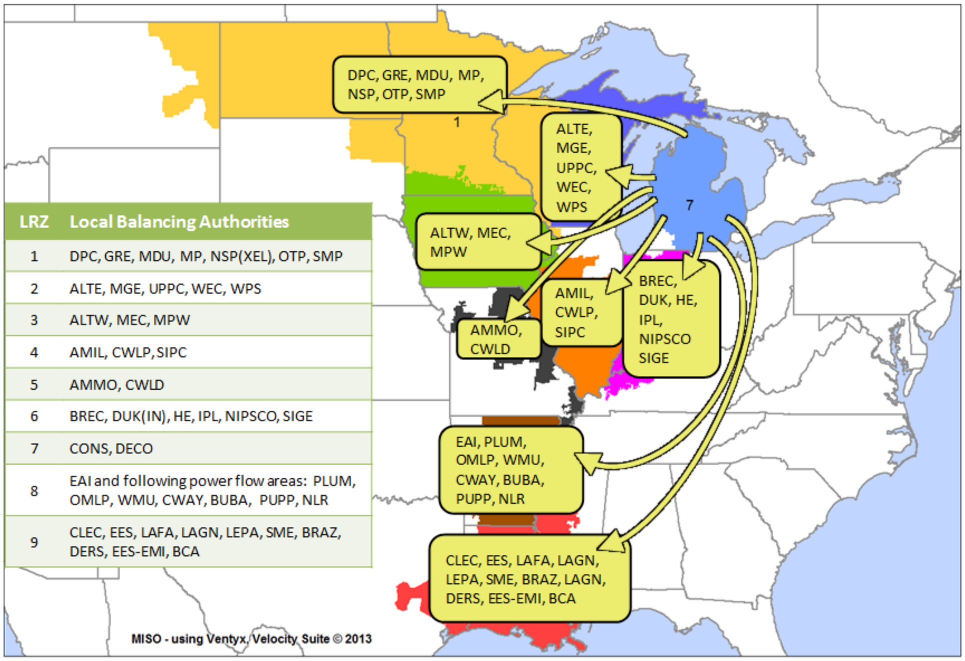

Figure 5.4: Example - MISO LBAs Used for LRZ 7 CEL

Redispatch

LOLE study redispatch is based on redispatch for baseline reliability projects, which is referenced in Section J.5.1.1 of the Transmission Planning Business Practice Manual (BPM). The common assumptions are as follows:

- Only shift factors greater than 3 percent are considered
- No more than 10 conventional fuel units or wind plants will be used
- Redispatch limited to 2,000 MW total
- Nuclear units are excluded

Units excluded from transfer analysis dispatch outlined above in the general assumptions section are not considered for redispatch. For import redispatch scenarios, all MISO planning resources in the zone being studied and adjacent systems (Tier 1 or Tiers 1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. If the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

For export redispatch scenarios, only MISO generation resources within the zone being studied are eligible to be ramped up. All MISO generation resources are eligible to be ramped down. As with import redispatch, if the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

Generation Limited Transfer for CIL/CEL

When conducting transfer analysis to determine a CIL or CEL, an LRZ may not reach a constraint caused by a transmission limit before running out of generation to dispatch. MISO has developed a process to identify transmission constraints when possible for both CIL and CEL. There may be instances in which a transmission limit is not identified due to one or a combination of the following: new transmission or change in generation.

After running the initial transfer analysis to determine limits for each LRZ CIL or CEL, MISO will determine whether a zone is experiencing a generation limited transfer. If the LRZ is experiencing a generation limited transfer, MISO will adjust the base model dependent on whether it is a CIL or CEL analysis, and re-run the transfer analysis.

For a CEL study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LBAs under study) MISO will adjust load and generation to balance the base model. In order to determine a limit, MISO will decrease load in exporting LBAs, as well as decrease the generation in the exporting LBAs. After the adjustments are complete, MISO will perform transfer analysis on the adjusted model to be in line with section 5.2.2.1. If a generation limited transfer is observed, the adjustments to the model would be repeated.

For a CIL study, when a transmission constraint has not been identified after (a) decreasing all generation within the LRZ under study, (b) or dispatching all generation within Tiers 1 & 2, MISO will adjust load and generation to balance the base model. In order to determine a limit for the LRZ under study, the load, the generation dispatch, and the maximum generation dispatch limits in the importing LRZ will be increased. After the adjustments are complete, the transfer analysis will be completed on the adjusted model to be in line with section 5.2.2.1. If a generation limited transfer is observed, the adjustments to the model would be repeated. This process can also be applied to Tiers 1 & 2 of an LRZ under study when completing a CEL Study.

Processing and Reporting Results

The transfer analysis results for each LRZ consist of a list of constraints and their corresponding FCITC and TTC values up to the requested transfer level. The constraint with the smallest FCITC will be used to determine the CIL and CEL. Limiting constraints in the area of system support resources will be further analyzed to determine if the constraints can be mitigated by excluding those resources from the study dispatch. The CIL and CEL are the total transfer capability of the corresponding limiting constraint. Refer to section 3.5.1 of the Resource Adequacy BPM for info regarding how the CIL impacts the Local Clearing Requirement (LCR) calculation. Stakeholder review of the constraints will occur through the LOLE working group.

If a zone's Local Clearing Requirement (LCR) is greater than the zone's Planning Reserve Margin Requirement (PRMR) and an existing MTEP project is not expected to increase the CIL, MISO will follow the process outlined in section 4.3.8.4 of the Transmission Planning BPM to identify a project to increase the zone's CIL.

Timeline and Posting of Results

Stakeholder review of power flow models and input files will be completed before analysis begins. The models and associated input files will be made available on the MTEP ftp site (ftp://mtep.midwestiso.org/lolewg).

The outcome of this process will identify a CEL and CIL for each of the LRZs. MISO will publish the CEL and CIL for each LRZ by November 1st preceding the applicable Planning Year, or at least thirty (30) calendar days prior to a TPRA.

5.2.2.2 Establishment of Local Reliability Requirement

Each LRZ's Local Reliability Requirement (LRR) is the amount of UCAP MWs required to yield a 0.1-day-per-year LOLE, without assistance from resources outside the respective LRZ at the load level for the LRZ at the time of the LRZ peak. The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

The LRR will be established using the following iterative process:

- Use the LOLE model in MARS to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and physical resources from the PRM Analysis.
- For each LRZ the model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage

rate will be added until the LOLE reaches 0.1 day per year for the LRZ. This is comparable to adding coincident peak demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the LRZ until the LOLE reaches 0.1 day per year for the LRZ.

The minimum amount of capacity above the zonal coincident peak demand required to meet the reliability criterion of a 0.1 day per year LOLE value will be utilized to establish the Local Reliability Requirement (LRR) for each Local Resource Zone. The per-unit LRR values are annually calculated by MISO and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit LRR values are multiplied by the total zonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) inclusive of Transmission losses to calculate each Local Resources Zone's Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

5.2.2.3 Establishment of Local Clearing Requirement

The final step in calculating an LRZ's LCR is to account for the external transmission ties by reducing the LRR by the capacity import limit determined in accordance with Section 5.2.2.1. The formula for determining the LCR is as follows:

$$LCR_{z1} = LRR_{z1} – \text{Capacity Import Limit}_{z1}$$

MISO will publish the LCR determinations by November 1st prior to the upcoming Planning Year.

5.3 Fixed Resource Adequacy Plan ("FRAP")

The FRAP will identify resources that an LSE has ownership or contractual rights that will be relied upon to meet the LSE's Planning Reserve Margin Requirement while also conforming to the Local Clearing Requirement ("LCR") in each LRZ where the LSE has a PRMR. The FRAP must be submitted via the MECT by the 7th business day of March prior to each Planning Year. MISO will review the FRAP and endeavor to notify the LSE of any issues by March 15th. LSEs will have until the PRA offer window opens to resolve any issues identified by MISO.

An LSE can designate its ZRCs in the FRAP up to the LSE's PRMR. ZRCs designated in the FRAP will be identified in the MECT. The ZRCs from these Planning Resources will be deducted from the available ZRC balance of that Planning Resource in the MECT. Any portion of an LSE's PRMR not covered by the FRAP or met through paying the Capacity Deficiency Charge will be cleared in the PRA.

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An LSE submitting a FRAP may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the ACP in the LRZ where the LSE has PRMR obligation and the ACP in the LRZ where the ZRC associated with the FRAP is physically located multiplied by the volume of the FRAP. A LSE can obtain a ZDC Hedge as a hedge against zonal price differences. Excess revenues collected from the PRA will be used to fund GMAs, ZDC Hedges, and Zonal Deliverability Benefit.

ZRCS and PRMR included in a FRAP will be modeled in the PRA.

LSE's Local Clearing Requirement for LSE's Using a FRAP

LSEs that choose to use a FRAP to meet their Resource Adequacy Requirements must designate a sufficient volume of resources located in the same LRZ as the LSE's PRMR to meet the LRZ's LCR requirement. The amount of resources that must be sourced from within the LRZ to satisfy the LSE's LCR share is equal to the load ratio share of the LSE's PRMR multiplied by the total LCR for its LRZ. The following formula is used to determine each LSEs Fixed Resource Adequacy Plan LCR requirements:

$$LSE\ LCR = \left[\frac{LSE\ PRMR}{Zonal\ PRMR}\right] * Zonal\ LCR$$

$$Minimum\ LSE\ FRAP\ ZONE\ = \left[\frac{LSE\ LCR\ X\ LSE\ FRAP\ NON\ ZONE}{(LSE\ PRMR - LSE\ LCR)}\right]$$

$$for\ the\ given\ LSE\ FRAP\ NON\ ZONE$$

$$Maximum\ LSE\ FRAP\ NON\ ZONE\ = \left[\frac{LSE\ FRAP\ ZONE * \ (LSE\ PRMR -\ LSE\ LCR)}{LSE\ LCR}\right]$$

$$for\ the\ given\ LSE\ FRAP\ ZONE$$

Where:

LSE LCR:	Amount of ZRCs that must be from the same LRZ as the LSE's PRMR if they met the entire PRMR using a FRAP.
LSE FRAP ZONE:	ZRCs that are in the same LRZ as the PRMR that is being met through a FRAP by the LSE
LSE FRAP NON ZONE:	ZRCs that are not in the same LRZ as the PRMR that is being met through a FRAP by the LSE
LSE PRMR:	Total PRMR the LSE has in the LRZ

Zonal LCR: The minimum amount of ZRCs that are located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ.

EXAMPLE:

LSE PRMR = 100 MW in LRZ 1

LSE LCR = 80 MW in LRZ 1

To apply ZRCs from other LRZs in the FRAP, the following condition must be satisfied:

$$\left[\frac{(LSE\ FRAP\ ZONE +\ LSE\ FRAP\ NON\ ZONE)}{LSE\ PRMR}\right] \leq \left[\frac{LSE\ FRAP\ ZONE}{LSE\ LCR}\right]$$

Case 1: LSE FRAP ZONE = 40MW in LRZ 1

LSE FRAP NON ZONE = 10 MW from LRZ 2

$$\left[\frac{(40+10)}{100}\right] \leq \left[\frac{40}{80}\right] \Rightarrow \left[\frac{1}{2}\right] \leq \left[\frac{1}{2}\right] \Rightarrow Pass{:}\ 10\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ allowed$$

$for\ the\ given\ LSE\ FRAP\ NON\ ZONE\ of\ 10\ MW,$

$$Minimum\ LSE\ FRAP\ ZONE\ = \left[\frac{80 * 10}{(100-80)}\right] = 40\ MW$$

NOTE: 40 MW represents the minimum amount of FRAP that must be fulfilled by the ZRCs in LRZ 1 in this case.

Case 2: LSE FRAP ZONE = 60 MW

LSE FRAP NON ZONE = 20 MW

$$\left[\frac{(60+20)}{100}\right] \leq \left[\frac{60}{80}\right] \Rightarrow \left[\frac{4}{5}\right] \leq \left[\frac{3}{2}\right] \Rightarrow Fail{:}\ 20\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ not\ allowed$$

$for\ given\ LSE\ FRAP\ ZONE\ of\ 40\ MW,$

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$$Maximum\ LSE\ FRAP\ NON\ ZONE\ = \left[\frac{60 * (100 - 80)}{80}\right] = 15\ MW$$

NOTE: 15 MW represents the maximum amount of ZRCs from other zones which can be used to FRAP LSE's PRMR in LRZ 1 in this case.

5.4 Hedges and Zonal Deliverability Benefit

5.4.1 Zonal Deliverability Benefit

Price separation between Local Resource Zones (LRZs) or groupings of LRZs, including Sub-Regional Resource Zone (SRRZs) occurs due to constraints binding in the Planning Resource Auction. Zonal Resource Credits will receive the Auction Clearing Price (ACP) based upon the LRZ where the Planning Resource underlying the ZRC is physically located.

As a result of price separation the Transmission Provider may collect more debits from Load Servicing Entitles (LSEs) than it credits the owners of the ZRCs. Excess amounts will be distributed in the following order:

1. Grandmother Agreements (GMA) owed payment
2. Zonal Deliverability Charge (ZDC) Hedges owed payment
3. Any remaining ZDB shall be distributed on a *pro rata* basis to Deliverability Benefit Zones (DBZs). A DBZ is a group of one or more LRZs with equal ACPs driven by the same auction constraint.

5.4.1.1 *Pro Rata* Allocation Methodology

The *pro rata* distribution is based upon the LSE's eligible PRMR which excludes PRMR associated with GMAs and ZDC Hedges.

MPs with Fixed Resource Adequacy Plans are eligible to receive ZDB.

The *pro rata* methodology to allocate ZDB uses a weighted average approach to calculate the benefit, in dollars, to importing DBZs of all exports within MISO – a weighted average exporting ACP. This weighted average pool of dollars is then allocated to importing DBZs within MISO on a *pro rata* methodology based upon the difference between the importing DBZ ACP and the weighted average exporting ACP and the MW amount of imports into a DBZ. The ACP for each LRZ within an importing DBZ is adjusted by dividing the benefit dollars allocated to the DBZ by the total PRMR of all LRZs within a specific DBZ. The specific steps to allocate ZDB are described below.

1. Subtract PRMR and ZRCs associated with GMAs or ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC).
2. Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint.
3. For each DBZ, subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
4. Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_j \times \text{ACP}_j)}{\sum \text{Net Export}_j}$$

Where j = Each net exporting DBZ

5. Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_k = \text{Net Import}_k \times (\text{ACP}_k - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

6. Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

FRAP Contribution to ZDB

Furthermore, ZDB includes credits collected from FRAPs that contain ZRCs located in LRZs that have a greater ACP than the respective PRMR's LRZ. This ZDB will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ where the ZRC associated with the FRAP is physically located.

Allocation of Zonal Deliverability Charge ("ZDC")

A FRAP will be subject to a ZDC if the ACP of the LRZ where the ZRC is physically located is less than the ACP of the LRZ where the PRMR associated with the FRAP is physically located. ZDC collected by the Transmission Provider that is not associated with a ZDC Hedge will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ where the PRMR associated with the FRAP is physically located.

A detailed example of ZDB *pro rata* allocation methodology is in Appendix P.

5.4.2 Grandmother Agreements ("GMA")

A GMA is a financial hedge against LRZ ACP differentials. GMAs for existing capacity agreements hold LSEs harmless from price separation as a result of adding locational requirements to the Resource Adequacy provisions. GMAs for existing LSEs will be allowed for Planning Years 2013-2014 and 2014-2015. For New LSEs, GMAs will be allowed for their transitional Planning Year and the next two full Planning Years. GMAs will be granted for a Planning Resource that clears in the Planning Resource Auction or Transitional Planning Resource Auction.

The following criteria are required for GMA approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year
- Contract must be executed and in place on or before July 20, 2011
- For existing LSEs, GMAs will expire at the end of the contract term, unit ownership change, unit retirement date, or by May 31, 2015, whichever is first
- For New LSEs, GMAs will expire at the end of the contract term, unit ownership change, unit retirement date, or after the first two full Planning Years following integration with MISO, whichever is first
- Register GMA in the MECT by November 1st prior to each Planning Year. Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Local Resource Zone, and Reservation number. Once the UCAP MW for Planning Resources is converted to ZRCs, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Local Resource Zone, and Reservation number information only. Updates will need to be completed by February 1st prior to the Planning Year.
- A separate GMA registration is required for each Planning Resource and load within each LRZ.
    - One Planning Resource in a registration can only select one LRZ.
- Transmission Requirements for GMAs need to meet one of the following three:
    - NRIS (aggregate deliverable plus eDNR) or;

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- NRIS Local or NITS (Network Designated TSR plus eDNR) or;
- Firm Point to Point for ERIS;
- The MW in GMA registrations should not exceed the LSE's PRMR, contract amount, ZRCs, and transmission Reservation.

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as GMAs, provided that the agreements otherwise satisfy the criteria.

Intra-zonal capacity transactions that become inter-zonal capacity transactions as a result of future revision to the LRZ boundaries during the two-year transition period will be eligible for the GMA hedge.

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the GMA Hedge provided that the GMA criteria is satisfied.

Firm resources that meet GMA Hedge criteria may be included as part of a FRAP or offered into the annual auction. Any MWs of ZRCs in a FRAP that are qualified under a GMA pursuant to Section 69A.7.7(a) will not be subject to a Zonal Deliverability Charge assessment.

An LSE submitting a FRAP may be subject to a ZDC. The ZDC is the difference between the ACP in the LRZ where the LSE has PRMR obligation and the ACP in the LRZ where the LSE Planning Resources are located times the volume of Planning Resources in the LRZ where their resources are located.

5.4.3 Historical Contract Eligibility for GMA

Although APRCs will cease to exist as of May 31, 2013, they can prequalify as GMAs as follows:

- Submit executed contract between MP requesting GMA and seller of APRCs requesting a GMA
- MISO will calculate annual UCAP MW of Planning Resources
- Market Participants will need to convert UCAP MW to Zonal Resource Credits (ZRC)
    - Zonal Resource Credits will have unit and LRZ specific identifiers
- As Market Participants transact ZRCs to fulfill contracts that meet criteria for hedge, MISO will be able to determine source of ZRCs to apply "Grandmothering" financial hedge to auction results

  - ZRCs transacted to fulfill existing contracts will need to have unit identifiers from aggregate deliverable generators
- Based on ZRCs transacted, MISO will work with the MP that qualified the GMA to determine which LRZ the Planning Resource is located
- LSEs with APRCs contracts must provide their Network Contract number as the TSR in addition to eDNR number which lists the Planning Resource being selected in the GMA registration. The eDNR can be provided in the comments field of the registration or as an attached document in the GMA registration.

If Load is located in an LRZ with a higher ACP than the LRZ where the Resource is located, Load will pay an amount equal to the difference in the ACPs between the LRZs, times the amount of the unhedged load if a GMA Hedge does not exist. After the two year transition period for GMAs concludes, the zonal deliverability benefit shall be distributed by the Transmission Provider such that ZDC Hedges are funded first, and then any excess credits are distributed on a *pro* rata basis per Section 5.4.1.1.

5.4.4 Zonal Deliverability Hedge

LSE can obtain a ZDC Hedge as described herein as a financial protection from zonal price differences. Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a ZDC Hedge. Also, any cost shared upgrades would not be eligible for a ZDC Hedge. The participant that funds the upgrades and submits the Transmission Service request is the participant who is eligible for the ZDC Hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1st prior to the Planning Year to demonstrate eligibility. ZDC Hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

5.5 Planning Resource Auction (PRA)

5.5.1 Timing of Auctions

The annual PRA will be conducted in the beginning of April, which is approximately two months before the beginning of the associated Planning Year. Any Transitional PRA will be conducted prior to the New LSE's integration date.

5.5.2 Amount of Capacity Cleared in Each Auction

The annual PRA and Transitional PRA shall clear ZRC offers in order to satisfy 100% of the PRMR for each LSE, less the amount of PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a FRAP, in each LRZ. If the total volume of ZRC offers is less than total PRMR, MISO will clear the total volume of offered ZRCs.

5.5.3 Conduct of the PRA

The annual and Transitional PRA shall be a sealed bid auction, which will determine the Auction Clearing Price (ACP) for each LRZ modeled in that auction. The auction shall determine the outcome of all ZRC offers accepted during the qualification process and submitted during the auction offer window.

Step 1: Compilation of Offers

Offers for the auction must be submitted in the MECT's Submit Offer screen during the auction offer window period. The offer window for the auction will be opened during the last three business days in the month of March prior to the start of the new Planning Year. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of a FRAP.

MISO shall compile all of the offers, as follows: The MP acting on behalf of any Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of ZRCs that the MP would commit to provide from the Resource in the associated modeled LRZ during the Planning Year. An offer shall be defined by the submission of up to five such pairs, each having a strictly greater price than the previous price in the submittal. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for each price. Each offer is separately evaluated.

Step 2: Determination of the Outcome

- MISO shall use the ZRC offers to determine the aggregate supply curves for each MISO modeled LRZ. MISO will use the offers in conjunction with the import and export constraints, local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the

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LRZ and not the size of a Resource (i.e. a LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear). At any non-zero clearing price, a pro-rated clearing from tied bids will be applied. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Inadequate Supply

While the auction will endeavor to select ZRC offers sufficient to meet the requirements of each LRZ, it is possible that sufficient resources are not available. In such cases, the auction will clear all ZRC offers in the LRZ at the Cost of New Entry (CONE) price approved by FERC and the LRZ or Transmission Prover region would be short of Planning Resources for the Planning Year.

5.5.4 Market Monitoring

All participation by Market Participants is subject to the market power mitigation rules described in Module D of MISO's Open Access Transmission Tariff.

5.5.5 Local Reliability Requirement

Local Reliability Requirements for each LRZ will be determined by MISO through engineering studies based on the 0.1 days per year loss of load expectation criteria for each LRZ in isolation. From this initially determined value (the Local Reliability Requirement) will be subtracted the import capability of the LRZ from the rest of MISO's system, resulting in the LCR value. Further details on the LCR can be found in the annual LOLE study report. MISO will provide the LCR to LSEs by November 1st prior to the upcoming Planning Year.

5.5.6 Target Reliability Value

The resultant target reliability value for each LRZ will be the greater of the system-wide Planning Reserve Margin Requirement based on MISO's PRM or the LCR value. The sum of these LRZ target reliability values will be the system's target reliability value, that is, the amount of UCAP MW that must be obtained, if available, from the auction.

5.5.7 Resource Offers

Any ZRCs that were not used in the FRAP can be offered into the PRA during the auction window period. The following business rules are applied to the ZRC offers for the PRA:

- Offer cannot be changed or withdrawn after the auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.

- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each zone is the annual Zonal CONE divided by 365
- The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e. LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear).
  At a zero-clearing price, all zero-price and price-taking offers will be accepted.

Self-Scheduling
LSEs that "self-schedule" ZRCs by submitting offers into the PRA with a price of $0.00 will always clear the auction.

Sub-Regional Constraints
The Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) are the transmission constraint parameters which must be respected, in addition to CILs and CELs for each LRZ, when conducting the PRA or in the Resource Replacement process. A SRRZ consists of more than one LRZ.

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs as soon as practical but no later than the first business day of March for the following Planning Year.

5.5.8 Simultaneous Feasibility Test (SFT)

Background
The test identifies transmission constraints resulting from power transfers between LRZs. To the extent transmission constraints cannot otherwise be mitigated via redispatch using Planning Resources, new CIL and CEL values (as applicable) are established. Resulting transfers in the auction will be simultaneously reliable and feasible. The SFT is completed after the auction clears and is driven by section 69A.7.1 of Tariff Module E-1.

Base Model
Base modeling represents the transmission topology and associated transmission ratings, demand, and anticipated net interchange for the upcoming summer. This is accomplished by the following modeling assumptions:

- Base model
  - Latest available MTEP model for MTEP project justification
- Transmission Topology

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    - Includes Appendix A and other Model On Demand projects in-service by June 1st
- Load
    - Coincident Peak Forecast and transmission losses plus Planning Reserve Margin
    - LMRs are modeled as reduction of PRMR where LMRs are physically located
- Dispatch
    - FRAP
    - ZRC offers cleared through the auction
- External representation
    - Latest Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group series model matching Planning Year timeframe

The model used for MTEP project justification provides the best representation of the system and is a better representation than the one year old LOLE model. The MTEP model contains the up-to-date topology and has gone through recent stakeholder review.

Interchange Detail

External units that clear the auction are accounted for by Balancing Authority Area and then the interchange between MISO and the Balancing Authority Areas with cleared units is adjusted to represent the cleared amount.

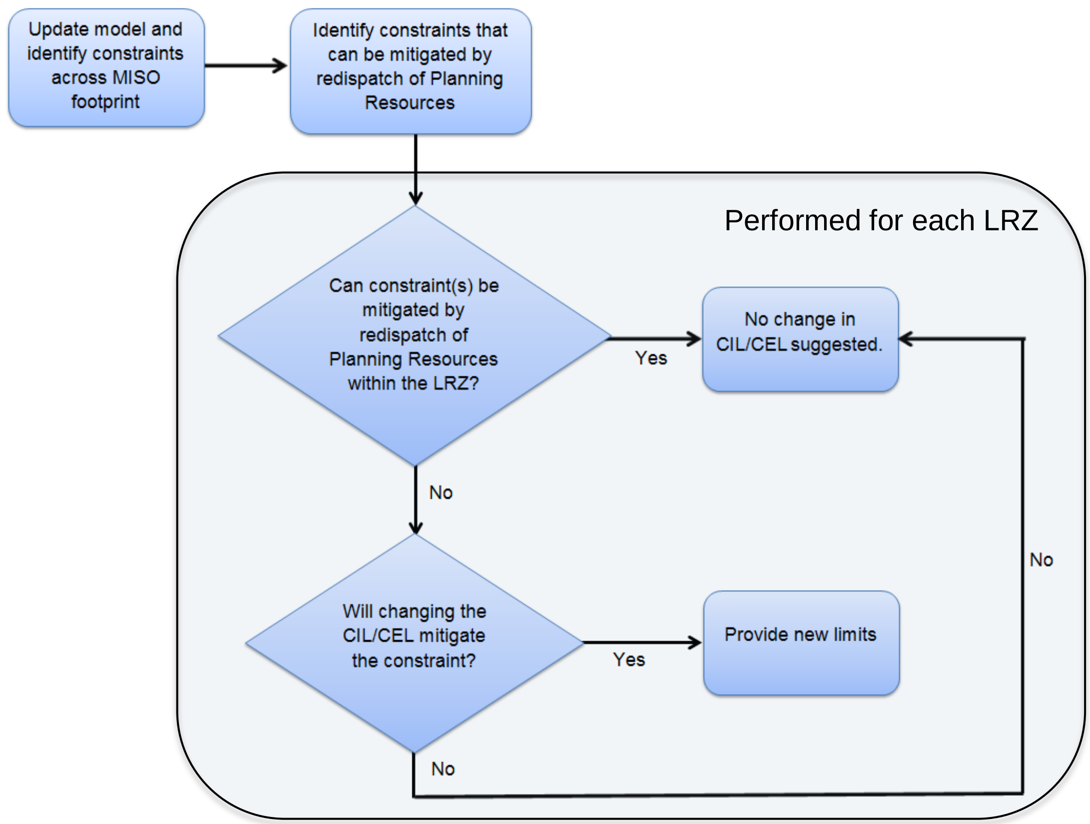
Topology Validation

Model checks are performed prior to the SFT. First, the ratings of facilities found to be limiting in the LOLE study are checked for rating changes. If the facility ratings are updated, the impact on CEL or CIL must be determined. Projects included in the LOLE models were expected to be in-service prior to June 1 of the Planning Year and in-service dates occasionally change, so the model is updated to include only those projects still expected to be in-service by June 1.

Powerflow Analysis

The only controllable elements of the auction are the CIL and CEL. The SFT determines if any changes to CEL and CIL are required. The initial limits are determined in the annual LOLE study. These limits are an input to the initial auction clearing process. The SFT process is outlined in Figure 1 below.

Figure 1: SFT Process Flow



CIL and CEL may be modified when the dispatch of Planning Resources outside the LRZ is the only action to mitigate constraints. To determine if changes are required, it must first be determined if the LRZ is an exporter or importer as a result of the auction clearing. If the LRZ is an exporter within the CEL bounds, no change to limits should cause the LRZ to export more. Similarly, no change to limits should cause an importing LRZ to import more. The changes to limits that are impactful for exporters and importers are outlined as:

- Potential change if Planning Resources outside an LRZ is the only mitigation identified
- Decrease export or import limit if Planning Resources outside LRZ can be ramped up or down respectively to mitigate the constraint
- Decrease limit by MW amount needed to mitigate constraint

The Tariff allows for up to three iterations of the auction clearing process. The first iteration uses the CEL and CIL from the LOLE study while the second and third iteration use any updated CIL and CEL values as determined by the SFT. The second and third iterations are performed only if needed. The clearing iterations are outlined as:

1st Pass

- Inputs to the auction clearing process are CILs and CELs from LOLE study, LCR, SRECs, and SRICs as applicable
- If all LRZs pass the SFT, auction results are final and the 2nd and 3rd iteration of auction clearing is not required.

2nd Pass

- Inputs to the auction clearing process are updated CILs and CELs from the 1st Pass and
- If all LRZs pass the SFT, results are final and the 3rd iteration is not required

3rd Pass

- Inputs to the auction clearing process are updated CILs and CELs from the 2nd Pass If all zones pass the SFT, results are final. If at least one LRZ does not pass the SFT, the iteration with the fewest MWs of network violations will be deemed as the final auction result.

5.5.9 Auction Results Posting

The MISO Capacity Market Administration team will post the summary of the annual or Transitional PRA results on its website ten (10) Business Days after the auction offer window is closed and any Transitional PRA Ten (10) Business Days after the auction offer window is closed. The summary includes the following information for MISO system wide and each LRZ: PRMR, Total Offer + FRAP, Offer Cleared + FRAP, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, deficient amount, and Total Offer Cleared volume for the system.

One month following the completion of any PRA, MISO will post the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

Resource Adequacy Settlement

Transmission Provider will settle the annual and any Transitional PRA using the following steps:

1. Determine the ACP for ZRCs and PRMR within each LRZ;
2. Provide GMA credits equal to the zonal ACP differential to Load subject to GMAs.
3. Provide ZDC Hedge credits equal to the zonal Auction Clearing Price differential to ZDC Hedge Load amounts.
4. Provide ZDB credits to all remaining PRMR in the LRZ. The ZDB is a credit against the ACP paid by LSEs with PRMR in each LRZ.

Settlement calculations for the PRA will be conducted on a daily basis and the results will be shown under the S7 Settlements statement. Please refer to the Market Settlements BPM for further details. There are four (4) charge types under the PRA Settlement:

- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's FRAP will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when a LSE clears more ZRC in the PRA than its PRMR. The LSEs that converted UCAP MW to ZRCs will receive the auction clearing price for the entire Planning Year for those ZRCs that cleared in the PRA.

5.6 Retail and Wholesale Load

Both the Retail and Wholesale Load switching between LSEs can be tracked through the MECT after the start of the new Planning Year. As a result of load switching, the PRMR of the LSEs involved in the load switching will change. Switching of Retail load will not change an Electric Distribution Company's (EDC) total area PRMR. Similarly, wholesale load transaction will not change the total MISO PRMR.

Retail Load Switching

By January 15th 11:59 p.m. EST prior to start of the new Planning Year, the LSEs will confirm the LSEs' share of the EDC's area Peak Load Contribution (i.e. PLC).The Retail LSE's PRMR will change during the Planning Year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

5.6.1 Wholesale (Non-Retail) Load Switching

For the case of the Wholesale Load switching, the amount of the PRMR transferred via the wholesale load transaction process will transfer the PRMR of the current LSE to the new LSE starting with the effective date specified in the wholesale transaction. The transaction must be confirmed in the MECT by both parties before the start of the effective date.

5.6.2 Peak Load Contribution (PLC)

The EDC calculates each retail LSE's load ratio share of the retail LSEs peak demand of the EDC's peak demand at the MISO Coincident Peak Load for the Summer prior to the Planning Year. The aggregate PLCs will be set equal to the PRMR of the EDC. Specific methods used by the EDC to calculate each Retail LSE's PLC must be provided to both MISO and LSEs no later than December 15th prior to the upcoming Planning Year. LSEs will have until January 15th to verify the EDC provided data in the MECT.

5.6.3 Retail Load Switching

The Retail Load screen in the MECT is provided for EDCs in Retail Choice states to track the Retail LSE's day-to-day migration of loads at the Asset Owner (AO) level.

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Using the daily retail load switching information in the MECT, MISO Settlements calculates the LSE's new PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

The daily retail load switching information includes:

- Name of the EDC
- Name of the LBA
- Operating Date of Retail load switching
- Name of AO(s)
- AO's new Retail MW (with granularity of tenth of a MW)

5.6.4 Wholesale Load Switching

A Wholesale Load obligation can be switched from one LSE to another using the Wholesale Load Switching screen in the MECT during the Planning Year. When Wholesale Load switching occurs, the daily capacity charges of Wholesale Load will be transferred from the current LSE to the new LSE. The PRMR for affected LSEs will be decreased or increased, as appropriate, by the amount of the wholesale load plus the PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Planning Year may enter a Wholesale Load switching contract representing PRMR in the MECT.

5.6.5 Settlements of Wholesale and Retail Switching

Both parties of a load switching agreement must confirm the transaction in MECT. All confirmed load switching information submitted by the Settlements deadline (per Market Settlements BPM) will be transferred to Market Settlements for settlement calculation purposes.

A LSE's PRMR will change based on the information submitted in the MECT for both Wholesale and Retail Load Switching.

MISO will calculate the new charges and credits by applying the Auction Clearing Price ("ACP") for the applicable LRZ to the new daily PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE's PRMR will change if Retail Load switching information in the MECT or daily load data for Settlements is resubmitted per the Settlement's rerun process (i.e. S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

5.7 Capacity Deficiency Charge

LSEs are allowed to opt out all or a portion of their PRMR participating in the auction by paying the Capacity Deficiency Charge. This is achieved by making a voluntary entry into the “Capacity Deficient Amount (MW)” field of the MECT equal to the MW amount of PRMR opting out of the auction before the auction window opens. Any amount of PRMR participating in the auction will pay the ACP for the LRZ where the PRMR is located. The Capacity Deficiency Charge for a LSE is the MW amount in the “Capacity Deficient Amount (MW)” field multiplied by 2.748 times the Cost of New Entry (“CONE”) for the LRZ where the LSE’s PRMR is located.

Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed on a *pro rata* basis based upon cleared MW of PRMR to other LSEs in the Transmission Provider’s footprint who did not opt to pay the Capacity Deficiency Charge. If the LRZ where the LSE opted to pay the Capacity Deficiency Charge failed to meet its LCR, then Capacity Deficiency Charge revenues will be allocated solely to LSEs within that LRZ that did not opt out of the auction by paying the Capacity Deficiency Charge. MISO will calculate the Capacity Deficiency Charge on the first business day after the results of the PRA have been published.

6 Performance Requirements

6.1 Must Offer Requirement and Monitoring

The must offer requirement applies to any Market Participant who converts the UCAP of a Capacity Resource to ZRCs and is used in a FRAP or clears in an auction. The must offer volume is calculated by dividing the amount of ZRCs cleared or used in a FRAP by (1 – XEFORd) of the Capacity Resource except for Intermittent Resources. The must offer for Intermittent Resources is based on the cleared ZRCs or ZRCs used in a FRAP divided by Resource credit (e.g. wind capacity credit for wind) as described in Section 4.2.3.5.

On a daily basis, MISO will monitor whether the offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market and first post Day-Ahead RAC process meet the must-offer requirements for the amount of Installed Capacity (ICAP) of the resource. MISO will compare the difference between the Emergency default Maximum Limit (MW) or scheduled maximum (MW) offer and the must-offer requirement (MW) for each hour of each day. If the Offers for Day Ahead and first post Day-Ahead RAC are less than the must-offer requirement, then MISO will compare the difference to approved outages or derates in MISO's Outage Scheduler (CROW) for such resources. Approved outages, approved derates, and offers will be captured based on the information provided at both the DA Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM. MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO's Outage Scheduler (CROW). They do not relieve the MP of the obligation to meet the must-offer requirement for the tolerance threshold volume will be applied at the CPNode level except for those resources noted otherwise in this BPM. The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

Offered MW (Emergency Max) > = must offer requirement less Threshold (excluding Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO).

If the amount of the approved outage or derate in CROW plus the appropriate threshold is greater than or equal to the above mentioned difference then the MP will have passed the must-offer monitoring check. Otherwise, the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the MECT portal of their must offer status. If a Market Participant believes there is a discrepancy in their must-offer report, the Market Participant can notify MISO via email to Resource Adequacy personnel of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage. MISO will review the information submitted and notify the Market Participant within seven (7) Business Days via email of the outcome of the review.

The IMM also has access to the reports published on the MECT portal and may contact Market Participants directly on any compliance issues.

6.2 Ongoing Calculation of CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each LRZ annually by September 1 of each year for the following Planning Year.

In calculating CONE values, the IMM and MISO will consider the following factors:

- Physical factors: type of resource, location, costs for fuel
- Financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- Other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE.

The table below contains the CONE values for each LRZ for Planning Year 20165-2017:

Local Resource Zone	Cost of New Entry
Local Resource Zone 1	$ 94,170
Local Resource Zone 2	$ 95,110
Local Resource Zone 3	$ 93,130
Local Resource Zone 4	$ 94,630
Local Resource Zone 5	$ 96,430
Local Resource Zone 6	$ 94,340
Local Resource Zone 7	$ 94,830
Local Resource Zone 8	$ 90,360
Local Resource Zone 9	$ 91,690
Local Resource Zone 10	$ 89,810

6.3 Replacement Resources

A Market Participant that registered Planning Resource that is being used to meet RAR and that will have its status changed to either 'retired' or 'suspended' must replace the resource effective prior to the actual date of the status change. Replacement may also be used by a MP with a cleared resource wishing to relieve its performance requirement may replace a resource with ZRCs from another resource that is not being used to meet RAR.

Replacement ZRCs may be sourced from any LRZ subject to LCR, CIL, CEL, SREC, and SRIC from the PRA. Planning Resource replacement transactions should be entered into the MECT tool at least seven (7) Calendar Days prior to effective date of replacement.

Replacement ZRCs can be from the Market Participant's own Planning Resources or ZRCs procured through the bilateral transactions from another Market Participant. When Planning Resources from the different LRZ are used for replacement, a MP must make sure that the LCR and CIL of the LRZ where the original Planning Resource is located are not violated. Furthermore, the MP must make certain the CEL of the new Planning Resource used for replacement is also not violated Finally, any ZRC replacement must not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements are also not violated.

ZRC replacements from LRZs other than that of the original resource will be processed in accordance with the following parameters:

- ZRC replacement shall be processed on a first come, first served basis.
- The amount of cleared ZRCs in each LRZ at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, TPRA and FRAPs.
The “Replacement Calculator” option is available in the MECT which can be used for verifying if the Planning resource being used for the replacement will meet all of the required LRZ parameters including LCR, CIL and CEL.

Replacement Calculator

The Replacement Calculator screen in the MECT is used to help MPs assess whether the ZRCs being used for the replacement will meet all of the required LRZ parameters including LCR, CIL, CEL, SREC, and SRIC.

The Replacement Calculator screen displays the PRMR, sum of cleared Offers and FRAPS, LCR, CIL, CEL, Total Import and Total Export for each LRZ from the PRA. Import Available and Export Available numbers are updated each time the Resource Replacement process is completed.

- Import Available number represents the maximum ZRCs allowed to import into the LRZ without violating the CIL. Import Available for the LRZ is calculated as:
  Import Available = CIL – Total Import from PRA + (Sum of all Export* - Sum of all Imports*)
- Export Available number represents the maximum ZRCs allowed to export out of the LRZ without violating the CEL. Export Available for the LRZ is calculated as:
  Export Available = CEL – Total Export from PRA + (Sum of all Import - Sum of all Exports*)

Example:

LRZ 1 has a LCR of 15,070 MW; an Import Available of 4,628.7 MW
LRZ 2 has an Export Available of 1,023.7 MW
LRZ 3 has an Export Available of 1,759.4 MW
Total MW needing replacement in LRZ 1: = 200 MW (Original Resource = AAA1)

Replacement ZRCs from LRZ 1: Of that 200 MW, 100 MW will be replaced by other Planning Resources located in LRZ 1 (Substitution Resource = AAA2)

ZRCs in LRZ 1 (after same LRZ replacement): LRZ 1's total ZRCs from LRZ 1 after replacement = Offers Cleared + FRAP - Total MW needing replacement + Replacement ZRCs from the same LRZ = 18,522.3 – 200 + 100 = 18,422.3

LCR Test: Since 18,422.3 > LRZ 1's LCR of 15,070, the LCR Test is "Pass"

Amount Exported: Remaining Replacement ZRCs of 100 MW are imported from LRZ 2 and LRZ 3:

- o LRZ 2's Exported ZRCs = 40 MW (Substitution Resource = BBB3)
- o LRZ 3's Exported ZRCs = 60 MW(Substitution Resource = CCC4)

Import Test: LRZ 1's total Imported ZRCs = 100 MW (40 MW + 60 MW). Since 100 MW < Import Available of 4,628.7, the Import Test is "Pass"

Export Test: Since LRZ 2's Export of 40 MW < Export Available of 1,023.7 MW and LRZ 3's Export of 60 MW < Export Available of 1,759.4 MW, the Export Test for LRZ 2 and 3 are "Pass".

This scenario will require the following 3 separate Resource Substitution Registrations to replace AAA1 for the full amount of 200 MW in LRZ 1:

- o First 100 MW of AAA1: replaced by AAA2 for 100 MW from LRZ 1
- o Second 40 MW of AAA1: replaced by BBB3 for 40 MW from LRZ 2
- o Remaining 60 MW of AAA1: replaced by CCC4 60 MW from LRZ 3

6.4 LMR performance

6.4.1 BTMG Performance

When a BTMG that either is used in a FRAP or cleared in a PRA fails to perform during an Emergency when given a Scheduling Instruction by MISO or the LBA, the penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increase and (b) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the applicable RSG charges.

The revenues from charges resulting from BTMGs that fail to respond in an amount greater than or equal to the Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation in response to a Scheduling Instruction or where the resource is claimed to be unavailable as indicated in the MISO Communication System (MSC) as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the BTMG not being available as needed during Emergency and may, if deemed appropriate, disqualify that resource from receiving ACP payments for that Planning Year. The BTMG may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period; or the resource has reached its registered maximum number of deployments).

In the event the same BTMG does not sufficiently respond or is unavailable, except for reasons of Force Majeure or other acceptable reasons defined in the Tariff or in this BPM on a second occasion during a Planning Year (with a separation period of at least 24 hours), the MP that registered the BTMG will be subject to the penalties described herein (if that BTMG fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above for its first performance failure, and the BTMG will no longer be eligible to receive ACP payments for the current Planning Year and for the next Planning Year.

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If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

6.4.2 DR Performance

If a DR that either is used in a FRAP or cleared in the PRA fails to perform during an Emergency when called on to reduce Demand by MISO or the LBA, penalties will be calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction as the sum of: (1) the product of (a) the amount of Load reduction not achieved, including Load above the registered firm service level for those DR registered as such and (b) the LMP at the CPNode associated with the DR; and (2) applicable RSG Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) the applicable RSG charges.

The revenues from charges resulting from DRs that fail to respond in an amount greater than or equal to the Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction or registered firm service level or the resource is unavailable, including those circumstances where the resource is unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the Summer period; or the resource has reached its registered maximum number of deployments).

In the event the same DR is not sufficiently responsive, including being unavailable, on a second occasion during a Planning Year (with a separation period of at least 24 hours) when needed by MISO to reduce Load; except when unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM, the MP that registered the DR that was used to meet Resource Adequacy Requirements will be subject to the penalties described herein The MP using the DR shall be assessed the same penalty as indicated above for a first performance failure, and the DR will no longer be eligible to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s)

7 Integration of New LSEs

This section serves as a guide for those New Load Serving Entities (LSEs) integrating into MISO's region between the time MISO has completed the annual PRA and the next Planning Year starts. Once the integration date is set, the MISO Resource Adequacy (RA) team will work with both existing and New LSEs to ensure that the newly integrating LSEs have sufficient Planning Resources to meet their anticipated Coincident Peak Load Forecast plus an appropriate planning reserve margin. To ensure the PRMR for new LSEs is met , MISO will conduct the Transitional PRA following the same registration requirements and auction protocols as the PRA.

New LSEs are encouraged to become familiar with the Resource Adequacy Business Practice Manual for a better understanding of their primary responsibilities and obligations.

MISO will have the following primary responsibilities for integrating New LSEs:

1. Define, as needed, new Local Resource Zone and their associated zonal parameters including:
    - Calculate CONE for the LRZ
    - Determine CIL and CEL
    - LOLE Analysis (Section 3.5.2)
    - Calculate Local Reliability Requirement (Section 5.5.5)

2. Calculate Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Planning Reserve Margin (Section 3.5.1)
    - Review of CPDF (Section 3.2.3)
3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Publish Auction Results (Section 5.5.8)

The MISO RA team will coordinate the proper timing of the data collection effort with the New LSEs for the successful completion of the Transitional PRA. The Transitional PRA will ensure that sufficient Planning Resources are procured to meet the PRMR of the newly integrating MISO region for the remaining Planning Year.

The RA Timeline for the annual PRA is shown in Appendix K. MISO will determine the RA timeline for the Transitional PRA and will publish it on the Resource Adequacy webpage under the Planning Section of the MISO public website. The RA timeline for the Transitional PRA will be reviewed by stakeholders prior to publishing on the MISO public website.

8. Testing Procedures and Requirements

8.1. Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J that apply for Planning Years 2011-2012 and beyond.

9. Appendices

Appendix A – Wind Capacity Credit

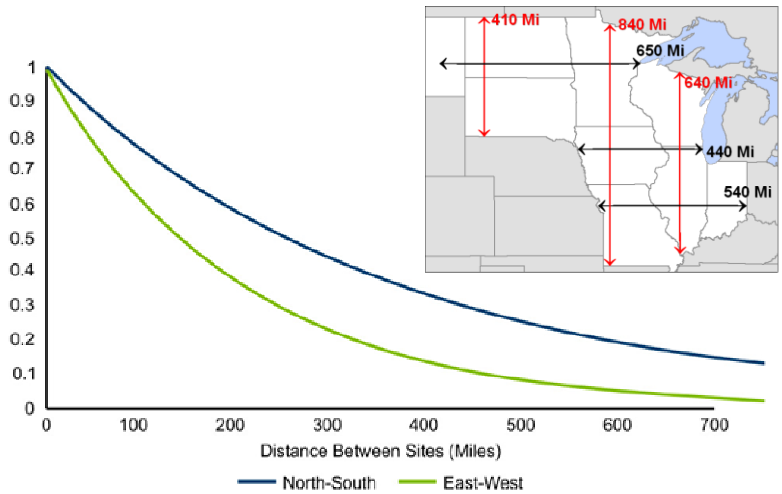
The basic goal is to estimate the reliable output of wind as a percentage of the installed capacity, for the MISO System and by CPNode. This involves the following data. Driving Data for Wind Capacity Credit

- The hourly load and the hourly wind output for 8,760 hours. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system wide Effective Load Carrying Capacity (ELCC) of the wind resources.
- MISO tracks the hourly wind output for the top 8 daily peak hours, by MISO total and individual wind CPNodes. The system wide and CPNode data is used to allocate the system wide Effective Load Carrying Capacity (ELCC) among individual CPNodes.
- MISO tracks the hourly amounts by which individual wind CPNodes are dispatched downward as part of the Dispatchable Intermittent Resources (DIR) activity. Similarly, MISO estimates the MW that CPNodes may have been curtailed.

Since 2009 MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO process as developed and vetted through the MISO stakeholder community consists of a two-step method. The first-step utilizes a probabilistic approach to calculate the MISO system-wide Effective Load Carrying Capability (ELCC) value for all wind resources in the MISO footprint. The second-step employs a deterministic approach using specific information about the location of each wind resource 'period metric' to allocate the single system-wide ELCC value across all wind CPNodes in the MISO system, to determine a wind capacity credit for each wind node.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. So for each upcoming planning year the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the ever increasing integration of new resources into the system. The sections of this write-up and current results illustrated here are broken down to describe the details of the two-step method adopted by MISO for determining wind capacity credit for the 2012 planning year.

Wind Output Correlation vs. Distance Between Wind Sites



Step-1: MISO System-Wide Wind ELCC Study
Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as that is often the time period (1 year) over which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one “with” and one “without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 3 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) LOLE criteria.

Example System "With" & "Without" New

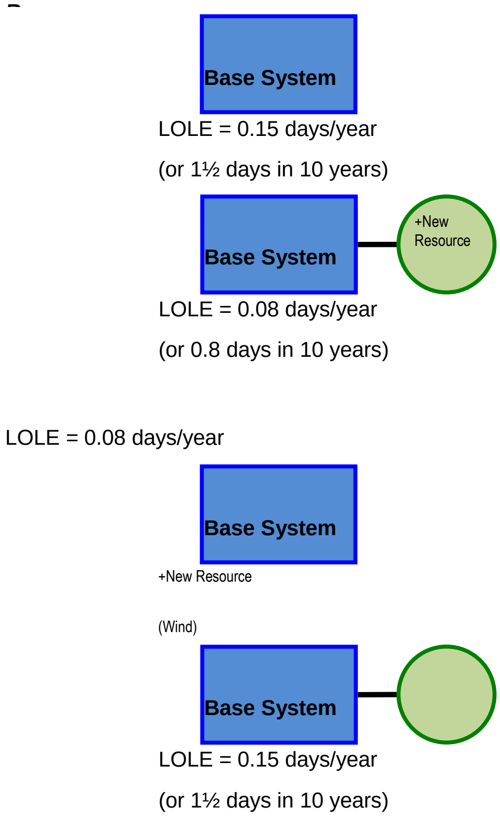


Figure 3 Example System "With" and "Without" New Resource

With each case being at the same reliability level, as shown in Fig. 4, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 – -200) for the new resource in this example. Sometimes this number is divided by the nameplate rating of the new resource and then expressed in percentage (%) form. The new resource in the ELCC example Fig. 4 has an ELCC of 30% of the resource nameplate.

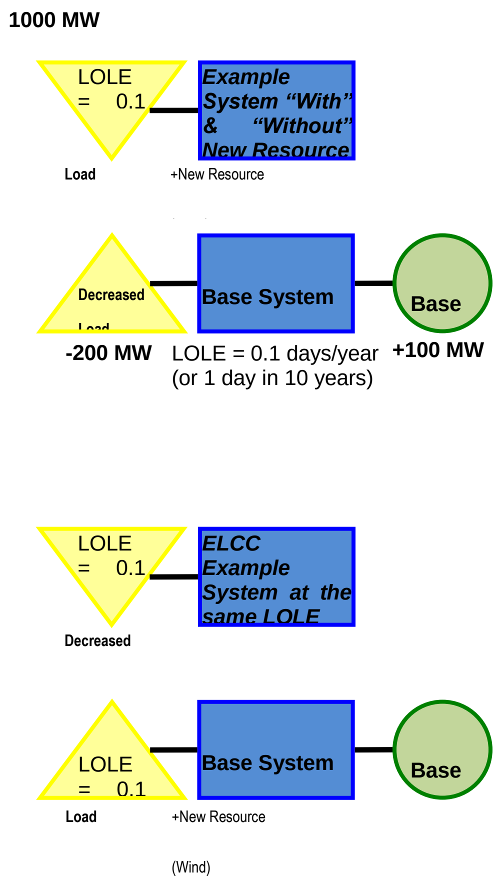


Figure 4 ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 4 was utilized as the analytical approach for the determination of the system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied there were two types of cases analyzed, ones with and ones without the wind resources. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. Using ELCC is the preferred method of calculation for determining the capacity value of wind [2].

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology MISO uses the Multi-Area Reliability Simulation (MARS) program by GE Energy to calculate LOLE values with and without the wind resource modeled. This model consisted of three major inputs:

- Generator Forced Outage Rates (FOR)
- Actual Historic Hourly Load Values
- Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These FOR are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system as well as the capacity throughout the country.

To incorporate historical information the actual 2005-2011 historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic ELCC values for the wind generation in the MISO on a system-wide basis. The last two columns in Table I illustrate the ELCC results for the 7-years of MISO historic data.

MISO System Wide ELCC Results

MISO calculated ELCC percentage results for historic years 2005 through 2011 and at multiple scenarios of penetration levels, corresponding to 10 GW, 20 GW and 30 GW of installed wind capacity. This creates an ELCC penetration characteristic for each year, as illustrated by the different curves in Fig. 5. The initial left most data point for each curve is at the lowest penetration point on each characteristic curve and represents the actual annual ELCC for that year; and the values are shown in the right column in Table I. The values along each year's characteristic curve at the higher penetration levels reflect what that year's wind resource would have as an ELCC if more capacity had been installed in that year, over the same MISO footprint. The high end 30 GW level of penetration is an estimate of the amount of wind generation that could result in MISO, as the Load Serving Entities (LSE) collectively meet renewable resource mandates of the various MISO States

The end of a 2nd Quarter is the convention used to set the capacity going into the next planning year. The penetration level at the end of the 2nd Quarter 2011 was 9.7%. Specifically as a percentage, the 2011 penetration level is the 2nd Quarter 9,996 MW in column-4 of Table 1 divided by the 102,804 MW peak load in column-1. The vertical line in Fig. 5 illustrates where the most recent historical 9.7% penetration level intersects each year's ELCC characteristic curve. The average of these seven intersect values is the 14.7% system wide ELCC assigned for the upcoming planning year 2012.

TABLE 1 MISO Historical Wind ELCC Values

Year	**MISO Peak Load** (MW)	**Registered Wind Max Capacity** (MW)	**Historical Wind Penetration** (%)	**System-Wide ELCC** (MW)	**System-Wide ELCC** (%)
2005	109,473	908	0.8%	152	16.7%
2006	113,095	1,251	1.1%	495	39.6%
2007	101,800	2,065	2.0%	57	2.8%
2008	96,321	3,086	3.2%	395	12.8%
2009	94,185	5,636	6.0%	173	3.1%
2010	107,171	8,179	7.6%	1,548	18.9%
2011	102,804	9,996	9.7%	3,007	30.1%

The ELCC characteristic of each year can be represented by a trend line equation that has an R2 coefficient of no less than 0.9996. This is the basis for achieving accuracy with sparse or few years of data. Alternative attempts to directly find a composite suitable single-trend-line curve to represent the aggregate 28 ELCC characteristic points of all seven years, met with poor R^2 coefficients in the range of 0.04 to 0.11.

Step-2: Wind Capacity Credit by CPNode Calculation

Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system (143 in 2011), a deterministic approach involving an historic-period metric is used to allocate the single system-wide ELCC value of wind to all the registered wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPNode locations, because in the MISO market the location relates to deliverability due to possible congestion on the transmission system. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance is a valuable input in determining the tradeoffs between constructing wind facilities in high capacity factor locations, that in the case of

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the MISO are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The system-wide wind ELCC value of 14.7% times the 2011 installed registered wind capacity of 9,996 MW results in 1,469 MW of system-wide capacity. The 1,469 MW is then allocated to the 143 different CPNodes in the MISO system. The historic output has been tracked for each wind CPNode over the top 8 daily peak hours for each year 2005 through 2011. The average capacity factor for each CPNode during all 56 (8-hours x 7-years) historical daily peak hours is called the “PKmetricCPnode” for that CPNode. The capacity factor over those 56 hours and the installed capacity at each CPNode, are the basis for allocating the 1,469 MW of capacity to the 143 CPNodes. MISO has developed business practice Manual for the handling of new wind CPNodes that do not have historic output data and for CPNodes with less than 7-years of data.

Tracking the top 8 daily peak hours in a year is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the PKmetricCPnode over multiple years.

Wind CPNode Equations

Registered Maximum (RMax) is the MISO market term for the installed capacity of a resource. The relationship of the wind capacity rating to a CPNode’s installed capacity value and Capacity Credit percent is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPnode n}} = \text{RMax}_{\text{CPnode n}} \times (\text{Capacity Credit \%})_{\text{CPnode n}}$$

$$(\text{Wind Capacity Rating})_{\text{CPnode n}} = \text{RMax}_{\text{CPnode n}} \times (\text{Capacity Credit \%})_{\text{CPnode n}}$$

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$$(\text{Wind Capacity Rating})_{\text{CPnode n}} = \text{RMax}_{\text{CPnode n}} \times (\text{Capacity Credit \%})_{\text{CPnode n}} \quad (1)$$

Where RMaxCPnode n = Registered Maximum installed capacity of the wind facility at the CPNode n. The right most term in (1), the (Capacity Credit %)CPNode n can be replaced by the expression (2):

$$K \times \left(PKmetric_{CPnode\ n}\%\right)\ K \times \left(PKmetric_{CPnode\ n}\%\right)\ K \times \left(PKmetric_{CPnode\ n}\%\right)$$
$$K \times \left(PKmetric_{CPnode\ n}\%\right)\ K \times \left(PKmetric_{CPnode\ n}\%\right)\ K \times \left(PKmetric_{CPnode\ n}\%\right) \quad (2)$$

Where "K" for Year 2011 was found by obtaining the PKmetric at each CPNode over the 7 year period, and solving expression (3):

$$K = \frac{ELCC}{\sum_{1}^{143} RMax_{CPnode\ n} \times PKmetric_{CPnode\ n}} \quad (3)$$

This results in the sum of the MW ratings calculated for the CPNodes equal to the system wide ELCC 1,479 MW. The values in (3) are:

ELCC = 1,469 MW

∑ RMaxCPnode n x PKmetricCPnode n = 1,803 MW

Therefore: K = 0.8148 = 1,469 / 1,803

Wind CPNode Capacity Credit Results & Examples

The individual PKmetric's CPnode of the CPNodes ranged from zero to 39.9%. The individual Capacity Credit percent for CPNodes therefore ranged from zero to 32.5%, by applying expression (2)

Example 1) For the best performing CPNode through 2011 data, the 39.89% PKmetric drives the capacity credit equal to:

- 32.5% = 39.9% x 0.8148, and therefore 32.5% times that CPNode's RMax would equal the Unforced Capacity (UCAP) rating for the best performing CPNode.
- Example 2) For the CPNode nearest the nominal 14.7% capacity credit through 2011 data, the 18.2% PKmetric drives the capacity credit equal to:
- 14.8% = 18.2% x 0.8148, and therefore 14.8% times that CPNode's RMax would equal the UCAP rating for that CPNode.

The MISO capacity credit method uses actual historical power output as a basis for setting the capacity rating of wind resources. While, MISO is currently limited to applying seven years of historical power outputs from the wind resources; by applying the developed ELCC and merging techniques the results are converging and are reflective as if one had more years of historical data available for the process. Fig. 9 illustrates the method over a range of limited data results. The left most point on the x-axis is the system wide result while utilizing only one year of data, the second point represents having two years of historical data available for the process. Progressively, the seventh point illustrates where MISO is currently at with seven years of data, and a projection sensitive to penetration is shown. As data from each new successive year becomes available, the subsequent capacity credit for successive years is expected to stabilize, and be more exclusively driven by penetration.

While the process discussed here represents a consistent and repeatable way to calculate the MISO market needs, MISO will continue to track and consider adjustments that may be required to deal with further aspects of common mode failure of wind generation. The MISO believes that the capacity credit for wind will be near 10% as the system approaches 25,000 to 30,000 MW of installed wind generation.

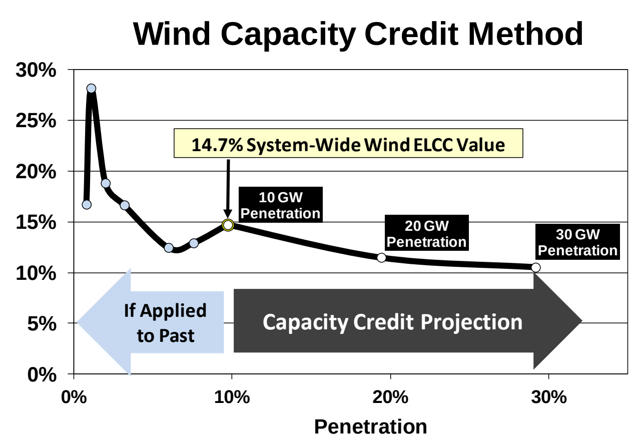

Figure 9 Applying Capacity Credit Method Starting with 2005 data

References

[1] Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-85, no. 8, pp. 910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; "Capacity Value of Wind Power," Power Systems, IEEE Transactions on, vol. 26, no. 2, pp. 564-572, May 2011

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Appendix B – Generator Testing and XEFORd details (OMC Codes)

There are outages from outside sources that result in generating units restricted in generating capabilities or in full outages. Such outages include (but are not limited to) ice storms, hurricanes, tornadoes, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated a list of OMC codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

GADS Cause Codes Outside Plant Management Control (OMC)

3600	Switchyard transformers and associated cooling systems – external
3611	Switchyard circuit breakers – external
3612	Switchyard system protection devices – external
3619	Other Switchyard equipment – external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st Substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st Substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc.)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9250	Low Btu coal

9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings 0 regulatory agency initiative
9502	Regulatory (nuclear) proceedings and hearings 0 intervener initiated
9504	Regulatory (environmental) proceedings and hearings 0 regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings 0 intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

Appendix C – Registration of Energy Efficiency Resources

Energy Efficiency Resource	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your Energy Efficiency Resource.
Energy Efficiency Resource Name	Enter Name of the Energy Efficiency Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this Energy Efficiency Resource is located
Local Balancing Area (LBA)	Select the LBA where this Energy Efficiency Resource is located.
Load Zone CPNode	Enter the CPNode where the Energy Efficiency Resource is located.
Program Information	Indicate if this is a new program or previously registered program
Program Inception Year	Select year program began
Program Name	Name of program that is being registered
Energy Efficiency Available at MISO Peak	Enter MW value of program at MISO Peak
Demand Reduction/Allocation	Enter MW value of program being used as a Planning Resource
Capability Added Each Plan Year	Enter MW difference in program from the Inception Year
Accreditation	Attach supporting documentation
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix D – Registration of DRs

Demand Resource (DR)	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your DR.
DR Name	Enter Name of the DR.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this DR is located
Local Balancing Area (LBA)	Select the LBA where this DR asset is located.
Load Zone CPNode	Enter the CPNode where the DR asset is located.
Retail Choice	Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer
Aggregate Retail Customer (ARC)	Check box if Resource registered as an ARC
Registered DRR	Indicate if this resource is registered as a DRR
DRR CPNode	Select the name of the DRR CPNode that is registered
Demand Reduction Capability at MISO's Peak	Indicate MW being registered at MISO's Peak
Accreditation	Choose accreditation method and attach supporting documentation
NERC Reporting	Provide 24 monthly MW levels associated with the installed capacity of the DR each month. Monthly values shall be provided for the first two years from the Effective Start Date. Provide 16 seasonal (Summer and Winter) MW levels associated with the installed capacity of the DR for each season. Seasonal values shall be provided beyond the 2 year monthly window.
City (where the LMR is located)	Enter the city where the DR is located.
County (where the LMR is located)	Enter the county where the DR is located.

State (where the LMR is located)	Enter the state where the DR is located.
Load Control Method	Select if load is direct control or interruptible load
EDR?	Check box if DR registered as an EDR
Emergency Demand Resource	Select the registered name of the EDR.
Curtail to Peak Firm Service Level	Check box if DR will curtail to firm service level
Monthly peak firm service levels	Enter monthly firm service level values for the PY if applicable
Plan Year Interruptions and Run Time	Select maximum number of events DR (minimum first 5 times needed during Summer) can be used and number of run hours (duration, minimum 4 hours)
M&V protocol to be applied to this DR	Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO Emergency. If other selected, please describe in box.
Notification details	Enter the notification time required for this DR. Notification time(s) must cover all hours and cannot be more than 12 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of DR. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix E – BTMG registration

Behind the Meter Generation (BTMG)	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your BTMG.
BTMG Name	Enter Name of the BTMG.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this BTMG is located
Local Balancing Area (LBA)	Select the LBA where this BTMG asset is located.
Load Zone CPNode	Enter the CPNode where the BTMG asset is located.
GADS Generator	Select the name of the GADS Generator(s)
NERC Reporting	Provide 24 monthly MW levels associated with the installed capacity of the BTMG each month. Monthly values shall be provided for the first two years from the Effective Start Date. Provide 16 seasonal (Summer and Winter) MW levels associated with the installed capacity of the BTMG for each season. Seasonal values shall be provided beyond the 2 year monthly window.
Plan Year Interruptions and Run Time	Select maximum number of events BTMG can be used, minimum first 5 times needed during the Summer, and number of run hours, minimum of 4 hours.
City (where the LMR is located)	Enter the city where the BTMG is located.
County (where the LMR is located)	Enter the county where the BTMG is located.
State (where the LMR is located)	Enter the state where the BTMG is located.
EDR?	Check box if BTMG registered as an EDR
Emergency Demand Resource	Select the registered name of the EDR.
M&V protocol to be applied to this	Select the protocol that should be applied. This is used

BTMG	for determination of whether the LMR performed if called on during a MISO declared Emergency. If other selected, please describe in box.
Startup notification time details (in hours)	Enter the notification time required to deploy this BTMG. Needs to be no more than 12 hours and cover all hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300)
Do you hold all permits in place necessary to operate this resource?	Indicate if all permits are in place in order for this resource to operate.
Do you hold all rights in place necessary to operate this resource?	Indicate if all rights are in place in order to operate this resource.
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)Resource Operator Contact Name (24 x7)	Enter phone number for 24 x 7 operator.Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact E-mail (24 x 7)Resource Operator Contact Phone Number (24 x7)	Enter e-mail address for 24 x 7 operator.Enter phone number for 24 x 7 operator.
Primary Contact Name (24 x7)Resource Operator Contact E-mail (24 x 7)	Enter name of person who should be contacted with questions on this registration.Enter e-mail address for 24 x 7 operator.
Primary Contact Phone (24x7)Primary Contact Name (24 x7)	Enter phone number of person who should be contacted with questions on this registration.Enter name of person who should be contacted with questions on this registration.
CommentsPrimary Contact Phone (24x7)	Submit any comments for this registrationEnter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix F – External Resources

External Resources	
Registration Requirements	**Explanation**
Plan Year	Select the Planning Year you are registering your External Resource.
EXTERNAL RESOURCE Name	Enter Name of the External Resource.
Description	Enter type of resources and additional names and sizes if registering more than one unit.
Registering Asset Owner	Enter the name of the entity that owns or has rights to this asset.
Local Resource Zone	Select the Local Resource Zone where this External Resource is located
Local Balancing Area (LBA)	Select the LBA where this External Resource asset is located.
Sink Load Zone CPNode	Enter the CPNode where the External Resource is sinking.
Direct Ownership or PPA	Indicate if the External Resource is Directly Owned or PPA
Direct Ownership	Enter MW value the Market Participant can register
GADS Generator	Select name of GADS Generator and input percentage if PPA otherwise select name of GADS generator
IDC Name	Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement.
GADS registered capacity increased	Indicate if this resource needs to have its capacity increased by PRM and XEFORd
Unit Type	Select Unit Type
Fuel Type	Select Fuel Type
Description	Provide Description of Unit Type and Fuel Type
Unit Size	Select Unit Size
External Balance Authority where Resource(s) are located	Enter Balancing Authority where Resource(s) are physically located.
Interface CPNode	Select Interface CPNode
NERC Regional Entity	Select NERC Regional Entity

Description	Provide description of NERC Regional Entity
Use Limited Qualification	Indicate if this Resource meets the Use Limited Qualification
Firm transmission to MISO border	Input effective date and OASIS reservation number and select Transmission Provider
Firm transmission within MISO	Input effective date and OASIS Reservation number
Have you notified the host BA?	Indicate if you have contacted your host BA of this registration.
Is this External Resource only be used as a Capacity Resource in MISO?	Indicate if you have a certified that this External Resource is only being used as a Capacity Resource for MISO.
Is this External Resource available the entire Planning Year?	Indicate if this External Resource is available for the entire Planning Year.
Have all other requirements been met?	Indicate if all other requirements have been met.
Resource Operator Contact Name (24 x7)	Enter who to contact for deployment of External Resource. The contact should be available 24 x 7 for commitment by MISO or LBA.
Resource Operator Contact Phone Number (24 x7)	Enter phone number for 24 x 7 operator.
Resource Operator Contact E-mail (24 x 7)	Enter e-mail address for 24 x 7 operator.
Primary Contact Name (24 x7)	Enter name of person who should be contacted with questions on this registration.
Primary Contact Phone (24x7)	Enter phone number of person who should be contacted with questions on this registration.
Comments	Submit any comments for this registration

Appendix H – Unforced Capacity (UCAP) Calculations for Planning Resources

The following sets of equations establish how the Unforced Capacity values (NRIS UCAP and ERIS UCAP) are determined for Planning Resources to account for resource performance and availability.

H.1 Planning Resource UCAP calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on MISO's Transmission System

The Unforced Capacity calculation is based on its type and volume of interconnection service, GVTC, and forced outage rate ($XEFOR_d$). The following steps are used to calculate NRIS UCAP and ERIS UCAP for each Planning Resource.

H.1.1 Planning Year UCAP Calculation

The following steps are used to calculate NRIS UCAP and ERIS UCAP for each Planning Resource.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

The next step is to convert the resultant Total Interconnection ICAP value to an Unforced Capacity value, Total Interconnection UCAP, by applying its forced outage rate (XEFORd).

A forced outage rate class average is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

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$$Total\ Interconnection\ UCAP = Total\ Interconnection\ ICAP \times (1 - XEFOR_d)$$

The final step is to allocate the Planning Resource's Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to calculate the NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. If the Planning Resource has provisional interconnection service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

$$\text{NRIS UCAP} = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRIS \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$\text{ERIS UCAP} = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

The NRIS UCAP and ERIS UCAP represent the capacity in MWs that is eligible to be converted into Zonal Resource Credits.

H.2 UCAP calculation for an External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource Unforced Capacity calculation is based on its GVTC and forced outage rate ($XEFOR_d$). The ERIS UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

$$ERIS\ UCAP = GVTC \times (1 - XEFOR_d)$$

A forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

The ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal Resource Credits.

H.3 Planning Resource UCAP calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, which does not have a Point of Interconnection on MISO's Transmission System

The Unforced Capacity calculation is based on its GVTC and forced outage rate ($XEFOR_d$) if it does not have a Point of Interconnection to MISO's Transmission System. The ERIS UCAP is calculated by applying its $XEFOR_d$ to its GVTC.

$$ERIS\ UCAP = GVTC \times (1 - XEFOR_d)$$

A forced outage rate class average is used if the Load Modifying Resource (BTMG) has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its fuel type and unit size.

The ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal Resource Credits.

H.4 UCAP calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

The Unforced Capacity is determined based on past historical performance and availability data for non-wind resources and through an effective load carrying capability study at 80% confidence level performed by MISO for Planning Resources fueled by wind. The Unforced Capacity calculation also considers the type and volume of interconnection service for a Planning Resource that has a Point of Interconnection to MISO's Transmission System.

H.4.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on MISO's Transmission System

The following sections establish how Unforced Capacity values (NRIS UCAP and ERIS UCAP) are determined for Intermittent Generation and Dispatchable Intermittent Resources that has a Point of Interconnection on MISO's Transmission System to account for resource performance and availability.

H.4.1.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the MECT Tool.

H.4.1.1.1 Planning Year UCAP Calculation for Wind Farms

MISO calculates a wind farm specific wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind. The wind capacity credit is determined by performing an Effective Load Carry Capability study on an annual basis and using wind farm specific past metered data, reference section 4.2.3.3 of the BPM for Resource Adequacy.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

The next step is to convert the resultant Total Interconnection ICAP value to an Unforced Capacity value, Total Interconnection UCAP, by applying its CPNode specific wind capacity credit.

$$Total\ Interconnection\ UCAP = Total\ Interconnetion\ ICAP \times (Wind\ Capacity\ Credit_{CPNode})$$

The final step is to allocate the Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. If the Planning Resource has provisional interconnections service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

$$\text{NRIS UCAP} = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRIS \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$\text{ERIS UCAP} = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

H.4.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.2.3.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

The next step is to convert the resultant Total Interconnection ICAP value to an Unforced Capacity value, Total Interconnection UCAP, by applying its forced outage rate (XEFORd). Intermittent Resources that do not report generator availability data already have their capacity value reflected in in the GVTC calculated in section 4.2.3. These units will show a XEFORd value of zero (0), and the Total Interconnection UCAP will be equal to the Total Interconnection ICAP.

$$Total\ Interconnection\ UCAP = Total\ Interconnection\ ICAP \times (1 - XEFOR_d)$$

The final step is to allocate the Total Interconnection UCAP based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to the NRIS UCAP. The remaining Total Interconnection UCAP will then be allocated to ERIS. If the Planning Resource has provisional interconnections service then the Planning Resource will receive zero (0) interconnection service and therefore the calculated UCAP will be zero (0).

$$NRIS\ UCAP = \begin{cases} Total\ Interconnection\ UCAP, & Total\ Interconnection\ UCAP \leq NRIS \\ NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

$$ERIS\ UCAP = \begin{cases} 0, & Total\ Interconnection\ UCAP \leq NRIS \\ Total\ Interconnection\ UCAP - NRIS, & Total\ Interconnection\ UCAP > NRIS \end{cases}$$

H.4.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following sections apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS UCAP represents the capacity in MWs that are eligible to be converted into Zonal Resource Credits.

H.4.2.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the Module E-1 Capacity Tracking Tool.

H.4.2.1.1 Planning Year UCAP Calculation

MISO calculates a wind farm specific wind capacity credit for each Planning Resource that is fueled by wind. The wind capacity credit is determined by performing an Effective Load Carry Capability study on an annual basis and using wind farm specific past metered data, reference section 4.2.3.3 of the BPM for Resource Adequacy.

$$ERIS\ UCAP = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$
$$(\quad)$$

H.4.2.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.2.3.

$$\text{ERIS}= GVTC$$

Appendix I – XEFOR$_d$ Calculation

To help better understand how the XEFOR$_d$ value is determined a description of the EFOR$_d$ has been provided below:

The equivalent forced outage rate demand calculation is based on the equation defined in the IEEE Standard No. 762 "*Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity*." This equation is shown below.

$$EFOR_d = \frac{FOH_d + EFDH_d}{FOH_d + SH} \quad x \quad 100\ \%$$

where:

$FOH_d = f_f$ x FOH

$EFDH_d$ = (EFDH – EFDHRS) if reserve shutdown events reported, or

= (f_p x EFDH) if no reserve shutdown events reported.

Please note that the IEEE Standard No. 762 and NERC definitions for EFDH differ slightly from the way MISO's PowerGADS tool calculates EFDH. These differences can be seen below.

IEEE and NERC's definition for EFDH: (Derated Hours * Size of Reduction)/Net Max Capacity
PowerGADS definition for EFDH: (Derated Hours * Size of Reduction)/Net Dependable Capacity

The Size of Reduction is equal to the Net Dependable Capacity minus the Net Available Capacity

f_f = full forced outage factor = (1/r + 1/ T)/(1/r + 1/T +1/D)

- r = average forced outage duration = (FOH)/(# of FO occurrences)
- D = average demand time = (SH + Synch Hours)/(# of unit actual starts)
- T = average reserve shutdown time = (RSH)/(# of unit attempted starts)

FOH = full forced outage hours
SH = service hours
Synch Hours = synchronous hours
RSH = reserve shutdown hours
EFDH = equivalent forced de-rated hours
EFDHRS = equivalent forced de-rated hours during reserve shutdowns

f_p = partial forced outage factor = ((SH + Synch Hours)/AH)
AH = available hours

Note:
Special cases are evaluated in the following order:
If reserve hours < 1, then f_f =1
Else if (SH + Synch hours) = 0, then f_f = 1
Else if (1/r + 1/T + 1/D) = 0, then f_f = 0
Else if # of FO occurrences = 0 or FOH = 0, then 1/r = 0
Else if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0
Else if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0
Else if (SH+RSH+Synch Hours) = 0, then f_p = 0
Else if ((SH + Synch Hours) + (f_f x FOH)) = 0, then $EFOR_d$ = 0

Example

Raw Data									
Unit	**Capacity(MW)**	**SH**	**RSH**	**AH**	**Actual Starts**	**Attempted Starts**	**EFDH**	**FOH**	**FO events**
1	55	4,856	2,063	6,918	34	34	146.99	773	12
2	75	4,556	1,963	6,519	31	31	110.51	407	5
3	120	3,942	3,694	7,635	36	36	19.92	504	11
4	153	6,460	516	6,978	17	18	131.03	340	14
5	180	6,904	62	6,968	14	16	35.81	138	12
Totals	**583**	**26,718**	**8,298**	**35,018**	**132**	**135**	**444.26**	**2,162**	**54**

Calculated Intermediate Values								
Unit	**1/r**	**1/T**	**1/D**	**f_f**	**f_f * FOH = FOH_d**	**f_p**	**f_p * EFDH = $EFDH_d$**	**$EFOR_d$**
1	0.0155	0.0165	0.0070	0.8205	634.25	0.7019	103.18	13.43%
2	0.0123	0.0158	0.0068	0.8049	327.61	0.6989	77.23	8.29%
3	0.0218	0.0097	0.0091	0.7756	390.92	0.5163	10.28	9.26%
4	0.0412	0.0329	0.0026	0.9657	328.34	0.9258	121.30	6.62%
5	0.0870	0.2258	0.0020	0.9936	137.11	0.9908	35.48	2.45%
Totals					**1,818.23**		**346.18**	**8.01%**

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$EFOR_d$ Calculation for Unit 1:

Synch Hours = 0

$$r = \text{average forced outage duration} = \frac{FOH}{\#\text{ of } FO} = \frac{773}{12} = 64.41667$$

$$T = \text{average reserve shutdown time} = \frac{RSH}{\#\text{ of Attempted Starts}} = \frac{2{,}063}{34} = 60.67647$$

$$D = \text{average demand time} = \frac{SH}{\#\text{ of Actual Starts}} = \frac{4{,}856}{34} = 142.82353$$

$$f_f = \text{full forced outage factor} = \frac{\frac{1}{r}+\frac{1}{T}}{\frac{1}{r}+\frac{1}{T}+\frac{1}{D}} = \frac{(0.0155+0.0165)}{(0.0155+0.0165+0.0070)} = 0.8205$$

$$f_p = \text{partial forced outage factor} = \frac{SH}{AH} = \frac{4{,}856}{6{,}918} = 0.7019$$

$$EFOR_d = \frac{FOH_d + EFDH_d}{SH + FOH_d} \text{ x } 100\% = \frac{(634.25+103.18)}{(4{,}856+634.25)} \text{ x } 100\% = 13.43\%$$

Additional Note: SH, RSH and Synch Hours are reported by the users in the Performance data. The rest of the statistics are calculated by PowerGADS based on Event data submitted by the users.

$EFOR_d$ for each unit is presented in the Generator Outage Rate Program (GORP) report. The statistics used in calculating $EFOR_d$ can be found in the Statistics Report and the Performance Report. The $EFOR_d$ calculation is applied differently for unique instances such as existing and new units. This calculation is based on the historical data from MISO's GADS database. Each unit's $EFOR_d$ value that is used for the Planning Year will be based on either a class average value for that particular unit's size and type or the unit's actual data. A class average value will not be blended with a unit's actual data to determine a 36 month $EFOR_d$ or $XEFOR_d$.

<u>Existing Units or Units with 12 or more consecutive months of actual data</u>: The $EFOR_d$ of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months. Eventually, each unit will have a 36 month $EFOR_d$ based on actual data.

Example: If a unit has 12 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 12 months.

If a unit has 27 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 27 months.

If a unit has 36 consecutive months of actual data only, then it is assigned an $EFOR_d$ value based on those 36 months.

New Units or Units with less than 12 consecutive months of actual data: The $EFOR_d$ of a unit in service less than twelve full calendar months shall be determined by the class average rate for units within the same range of capability and type. A unit will use the class average value until 12 consecutive months of data is obtained and a new Planning Year has occurred.

Units with Low Service Hours BPM Language

Units with an average of 80 service hours or less per year can have their service hours adjusted if the unit has at least 12 consecutive months of GADS data. The adjusted service hours will be based on 240 service hours (80 service hours x 3 years) or a fraction of 240 if less than 36 consecutive months of GADS data. This adjustment will be performed automatically by MISO staff. The calculation for the adjustment is as follows:

Qualification: SH ≤ (MO/36 * 240)
SH = Service Hours (actual)
MO = consecutive Months in operation
Adjusted Service Hours, if qualified:

$$\left[\left(\frac{Actual\ Starts}{Attempted\ Starts}\right)\cdot\left(\frac{Months}{36}\cdot 240 - SH\right)\right] + SH = SH'$$

External Resources: Market Participants are responsible for making sure that GADS data is submitted from the External Resources that they are seeking qualification as ZRCs. The Market Participant can submit this data to MISO's GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the MISO Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator then it is the Market Participant's responsibility to receive and submit this data for the External Resource.

Pooled Class Average Rates: The class average values are only used in place of actual data when such data are not available either due to the unit being new, or without adequate historical performance or operating statistics. These values are calculated from MISO's GADS database based on unit size and type. MISO's EFORd classes will be the same as defined by NERC's Generating Unit Statistical Brochure.

- Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous Months, which is not the result of a planned maintenance outage.
- MP will have to notify MISO RA team in writing within 75 days of the Catastrophic Outage occurring that includes description of Catastrophic Outage, date of outage, etc.
- Under annual construct, if MP chooses not to replace Planning Resource that suffers a Catastrophic Outage the XEFORd will be based on GADs submitted
- If MP chooses to replace the Planning Resource of a unit that suffers a Catastrophic Outage, the EFORd will be based on class average when the unit returns
    - Resource replacement is completed within 75 days of catastrophic outage or date of notification to RA team whichever comes first
    - Resource replacement must be in accordance to section 6.3 of this BPM
    - Once unit returns from Catastrophic Outage, the Planning Resource qualification requirements still apply

Fleet Weighted Average Forced Outage Rates

External Resources may participate using a fleet of resources. A weighted average forced outage rate is calculated using the individual unit rates and GVTC. The resulting rate is applied to the total fleet GVTC to determine the fleet UCAP.

Appendix J – GVTC Testing Requirements

All Generation Resources, External Resources, Demand Response Resources backed by behind-the-meter generation and BTMG that intend to qualify as or being used as a Planning Resources are required to perform a real power test or provide past operational data that meets these requirements to determine its GVTC and submits its GVTC data to MISO's PowerGADS.

If a Planning Resource fails to perform a real power test during the testing period and report the test information to MISO's PowerGADS by the reporting deadline, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero (0) UCAP MWs for the upcoming Planning Year.

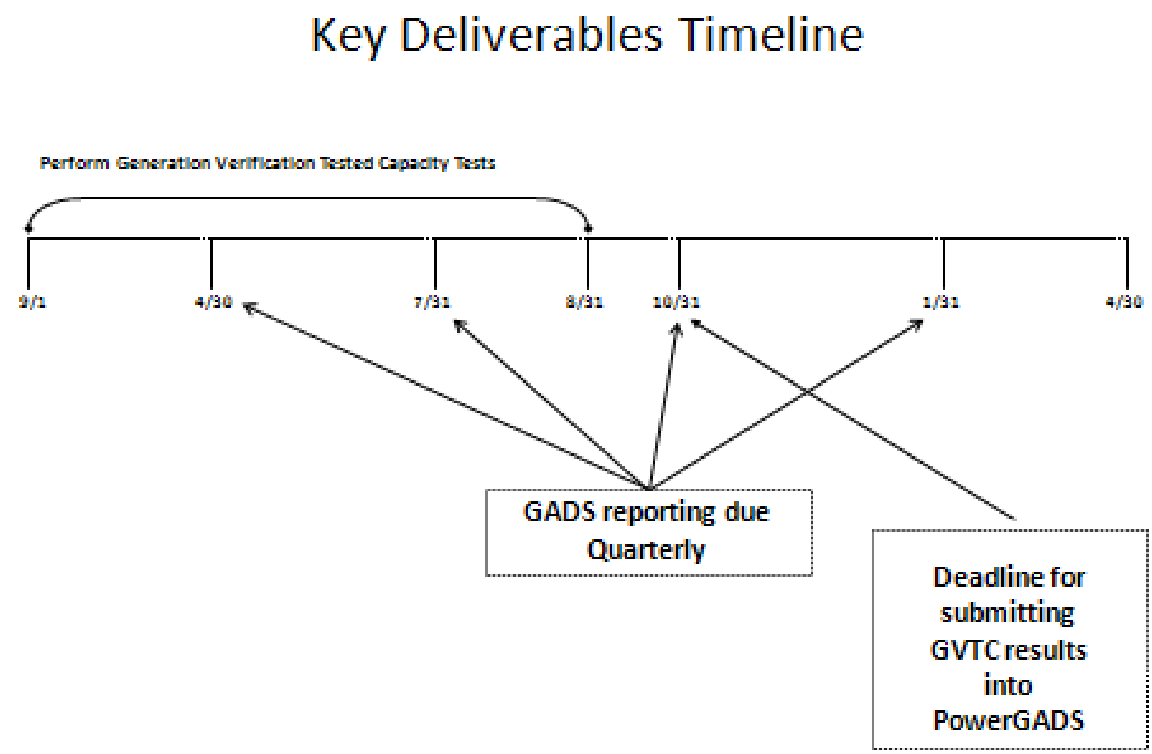
J.1 Generation Verification Test Capacity (GVTC)

The maximum Energy output (MW) that a Generation Resource, External Resource, Demand Response Resource backed by behind the meter generation, or Behind the Meter Generation (BTMG) can sustain over the specified period of time, if there are no equipment, operating, or regulatory restrictions, minus any Capacity utilized for the units station service power.

J.2 When to Perform and Submit a Generation Verification Test Capacity

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. The real power test shall be performed or past operational data must be provided during the test period between September 1st and August 31st prior to the upcoming Planning Year
    - A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC.
    - A real power test is required when returning from a suspended state and then submit the GVTC
    - A real power test is required when any existing or new unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time
        - A real power test is required for Planning Resources in an approved "Suspension" status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item,

including timing and cost requirements, when requesting a facility specific reference level.



1

J.3 Adjustment to establish the GVTC

The GVTC shall be temperature corrected to the average temperature of the date and times of MISO's coincident Summer peak, measured at or near the generator's location, for the last 5 years. MISO publishes the date and time of the past 5 annual coincident Summer Peaks. When local weather records are not available at the plant site the values shall be determined from the best data available (i.e. local weather service, local airports, river authority, etc.).

The adjustments required to establish the GVTC of a unit include, as appropriate for each electric generating technology, ambient temperature, humidity, condensing water temperature and availability, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in MISO GADs lasted a minimum of 90 consecutive days prior to the test data and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact MISO's Resource Adequacy Department for a review of its request.

J.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

J.5 GVTC Real Power Test Requirements

J.5.1 Thermal Steam and Nuclear

The GVTC capability will be validated for each unit type for a period of not less than two (2) continuous hours and will be the average of the two (2) hours.

Generating units GVTC as affected by the turbine exhaust pressure will be corrected to the past five years (or if a generating unit has not been in operation for five years or more, then as many years as the unit has been in operation) average daily maximum circulating water temperature measured at the date and time of MISO's Summer Peak. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Summer Peak.

Steam conditions will correspond to operating standards established by the generator owner for the unit or plant.

Capability of nuclear units will be determined taking into consideration the fuel management program and any restrictions imposed by regulatory agencies.

J.5.2 Combined-cycle units

The gross capability and net continuous GVTC will be validated for a period of not less than two (2) continuous hours and will be the average of the two (2) hours that result in the highest GVTC.

Generating unit GVTC as affected by the turbine exhaust pressure will be corrected to the past five years (or if a generating unit has not been in operation for five years or more, then as many years as the unit has been in operation) average daily maximum circulating water temperature measured at the date and time of MISO's Summer Peak, and the ambient air temperature and humidity conditions experienced at the unit location at the time of MISO's Summer Peak. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Summer Peak given humidity conditions experienced at the unit location at the time of MISO's Summer Peak.

GVTC of a unit shall be reported for the unit as a whole, as well as for the individual combustion turbine(s) and the steam turbine(s).

Steam conditions will correspond to the operating standard established by the Generator Owner.

The unit shall be operated with the regularly available type and quality of fuel.

The determination of the GVTC of a combined-cycle unit will depend on the structure of the complete unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this reporting manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion turbine(s) and steam components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

J.5.3 Combustion Turbine, Internal Combustion, and Diesel Units

The gross capability and continuous GVTC will be validated for a period of not less than one (1) hour.

Ambient temperature and humidity conditions to be used for adjusting the measured test output shall be the average for the past five years of the maximum temperature and humidity occurring the day of MISO's system summer maximum peak. Where inlet cooling is used to reduce turbine inlet air temperature; the temperature at the discharge of the Inlet coolers shall be the basis for ambient temperature adjustment.

Unit shall be operated with regularly available type and quality of fuel.

For a facility that consists of multiple units, auxiliary load for a shared auxiliary power system shall be allocated to the individual units to compute unit net capability.

J.5.4 Hydroelectric Units – Pumped storage and Reservoir

The gross capability and continuous GVTC will be validated for a period of not less than one (1) hour.

The GVTC established for hydroelectric plants shall recognize the head available giving proper consideration to environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The historic median head shall be determined as the median of all head measurements for hours ending 15, 16, and 17 EST for all days of the Summer (June, July, August) from the most recent five (5) years up to the most recent fifteen (15) years for Reservoir Hydro and Pumped Storage. If 15 years of historic data is not available for this period when the 15 year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15 year requirement is met.

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

Reporting

The following information shall be reported to MISO's GADS as appropriate. Please consult MISO's *Net Capability Verification Test User Manual* for more details with respect to the fields shown below.

CARD	Must be "90"
Utility	Required
Unit	Required
Year	Required
Period	Must be "S" for Summer
Test Index	Must be a "1"
REVISIONCODE	Must be "0" for initial upload, "R" to Revise, or "D" to Delete
Corrected Net	Leave Blank
Claimed Installed	Leave Blank
Difference	Leave Blank
Unit Type	Optional. If entered should be CT, ST, DS, HD, NU, CC, FB or PS
Test Start Date	Required
Test End Date	Required
Gross MW	Required
Station Service	Required
Process Load Served	Required
Net Test Capability	Required
Reactive Generation MVAR	Optional
Total Power MVA	Leave Blank
Power Factor	Leave Blank
Dry Air Temperature Observed	Required for certain unit types
Dry Air Temperature Rated	Required for certain unit types
Air Temperature Correction	Required
Relative Humidity Observed	Required for certain unit types
Relative Humidity Rated	Required for certain unit types
Relative Humidity Correction	Required
Cooling Water Temperature Observed	Required for certain unit types
Cooling Water Temperature Rated	Required for certain unit types
Cooling Water Temperature Correction	Required

STANDARD	Must be "MISO"

Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's *Net Capability Verification Test User Manual*.

Appendix K – Resource Adequacy Timeline

Month	Day	Process	Responsible entity
Sep	1st	MECT available for data submission	MISO
Sep	1st	Annual Cost of New Entry for LRZs filing due to FERC	MISO
Oct	1st	Transmission losses by Local Balancing Authority are posted by MISO	MISO

Oct	31st	• Generation Verification Test Capacity due in GADS
		• Generator Availability Data due in GADS for those resources that are required to report
		• Updated historical performance submittal due for hours ending 15, 16, and 17 EST in June, July, and August for:
		  ○ Intermittent Generation
		  ○ Intermittent BTMG that are not powered by wind
			Resource Owner

Nov	1st	Coincident Peak Demand forecast by LSE/EDC , Non-Coincident Peak, and energy forecast values by LSE due	LSE, EDC
Nov	1st	Loss of Load Expectation study results published by MISO (Publish PRM, Develop LRZs, Determine CIL and CEL, Establish LRR)	MISO
Nov	1st	Evidence for new GMA/Zonal Deliverability Charge hedges due	LSE
Dec	1st	Unforced Capacity values are published by MISO	MISO
Dec	15th	Peak Load Contribution submissions by EDC due (EDC will send the details of the PLCs to both the respective LSEs and the MISO for their review)	EDCS in Retail Choice
Feb	1st	Loss of Load Expectation study begins for next Planning Year	MISO
Feb	1st	Existing Load Modifying Resource/Energy Efficiency Resource/ External Resource must be submitted for approval in the MECT for the prompt Planning Year	LMR Owner
Feb	15th	Written letter from officer of company stating intention to leverage GVTC deferral provisions	MP
Feb	15th	New Load Modifying Resource / Energy Efficiency Resource / External Resource registrations to be	MP

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		considered for inclusion in FRAP must be submitted for approval.	
Feb	16th	Submit data for facility –specific reference level(s) to IMM due 45 days prior to the close of the PRA (optional)	Gen. Owner
Mar	1st	IMM publicly posts Reference Level for Planning Resources generic data 30 days prior to the close of the PRA	IMM*
Mar	1st	New Load Modifying Resource/Energy Efficiency Resource/ External Registrations must be submitted for approval in the MECT for the prompt Planning Year	LMR Owner
Mar	1st	Generator Verification Test Capacity/Generator Availability Data for new resources or resources with increased capacity prompt Planning Year	LMR Owner
Mar	1st	MISO to complete its Coincident Peak Demand forecast review process	MISO
Mar	1st	Grandmother Agreement and Zonal Deliverability Charge hedge information posted by MISO	MISO
Mar	1st	Credit requirements resulting from GVTC deferral due.	MP
Mar	1st Bus. day	No later than this date. Publish Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ)	MISO
Mar	7th Bus. day	Fixed Resource Adequacy Plan due by LSE	LSE
Mar	15th	Fixed Resource Adequacy Plan review completed by MISO.	MISO/LSE
Mar	25th	Complete initial Planning Resource registration review for new and existing registrations	MISO
Mar	25th	Provide facility-specific Planning Resource Level (s) to MP data 5 days prior to the close of the Auction	IMM
Mar	1 day prior to the 3rd to last business day	"Capacity Deficient Amount" entry due in the MECT	LSE
Mar	Last 3 Bus. Days	Planning Resource Auction offer window is opened	MISO
Mar	Last Bus. Day	Planning Resource Auction offer window is closed	MISO

Apr	1st 10 Bus. Days	Iterations of auction runs with the adjusted CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding.	MISO/IMM
Apr	10th Bus. Day	Planning Resource Auction results posted	MISO
Apr	11th Bus. Day	Assess the Capacity Deficiency Charge	MISO
Apr	16th Bus. Day	MISO sends out the Capacity Deficiency Charge	MISO
April (start of Bus Day count)	16th Bus. days + 7 Bus.Days	Capacity Deficiency Charge payment due	MISO
April (start of Bus Day count)	16th Bus. days + 7 Bus Days + 2 Bus. Days	Capacity Deficiency Charge payments made to MPs	MISO
May	Last Bus. Day	GVTC test needs must be submitted to MISO in order to avoid GVTC Deferral Non-Compliance Charge.	MP
Jun	1st	New Planning Year starts	All
Jun	1st	Assessment of GVTC Deferral Non-Compliance Charge begins	MISO

Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak from the previous calendar year.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour.

The LBA transmission loss percentage calculated by the Transmission Provider will apply to the LSE's applicable LBA Coincident Peak Demand forecast to determine the LSE transmission losses. PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Appendix M – Auction Formulation

Planning Resource Auction Software Formulations

Disclaimer

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Purpose of this document

MISO's Resource Adequacy Enhancement construct provides LSEs in MISO footprint an ability to procure planning resources through an annual Planning Resource Auction (PRA). An AIMMS based Auction Clearing Tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization objective function that is used for clearing the PRA and explains how zonal Auction Clearing Prices would be calculated.

AIMMS ("Advanced Interactive Multidimensional Modeling System") is an integrated modeling system that supports modeling and solving large-scale optimization problems.

Notations

Set Z = {All zones in the market}

Set G = {All resources in the market}

Set G_k = {All resources in zone k}

PRM = Planning Reserve Margin

$PRMR_k$ = Planning Reserve Margin Requirement for Zone k

$CPDF$= Coincident Peak Forecasted Demand

CIL_k = Capacity Import Limit for zone k

CEL_k = Capacity Export Limit for zone k

LCR_k = Local Clearing Requirement for zone k

$ZReq_k$ = Total capacity requirement for loads in zone k

$$ZReq_k = \max\{PRMR_k, LCR_k\}$$

$$PRMR_k = CPDF_k \times (1 + PRM)$$

$OfferPrice_i$ = The offer price for resource i

Note: In this document, a resource can offer only one price. Multiple price segments are treated as multiple resources.

$OfferMW_i$ = Offered MW value for resource i.

$MWCleared_i$ = Cleared MW value for resource i.

$P1_k, P2_k$ = Penalty prices for shortage

$SSlack_k, ZSlack_k$ = Slack variables representing capacity shortage, nonnegative

$ZACP_k$ = Auction Clearing Price for Zone k

$CONE$ = Cost of new entry

Objective Function

The auction is cleared by solving the following optimization problem. The objective function is expressed with the following mathematical terms:

Minimize $f =$

$$\sum_{i=1}^{m} OfferPrice_i \times MWCleared_i + \sum_{k=1}^{Z} (P1_k \times SSlack_k + P2_k \times ZSlack_k)$$

The slack variables are used to make sure the LP is feasible. The penalty prices are set to be a little higher than CONE values.

Constraints:

C1) $MWCleared_i \leq OfferMW_i$

C2) $MWCleared_i \geq 0$

C3) $\sum_{i \in G} MWCleared_i + \sum_{k=1}^{Z} SSlack_k = \sum_{k=1}^{Z} ZReq_k - \varepsilon_0$

This is the system demand constraint, its shadow price is referred as *SPsys.*

ε_0 is nonnegative and would be less than 0.001.

If ε_0 equals zero, the shadow price *SPsys* may not be unique at certain situations.

A small positive ε_0 would ensure *SPsys* is unique.

C4) $\sum_{i \in G_k} MWCleared_i + SSlack_k \geq ZReq_k - CIL_k - \varepsilon_k$

Each zone has a minimal clearing constraint with corresponding shadow price $SPmin_k$.

ε_k is nonnegative and would be less than 0.001.

C5) $\sum_{i \in G_k} MWCleared_i + SSlack_k \leq ZReq_k + CEL_k + \varepsilon_k$

Each zone has a maximal clearing constraint with corresponding shadow price $SPmax_k$

Again, the purpose of ε_k is to guarantee a unique shadow price $SPmax_k$.

C6) $\sum_{i \in G_k} MWCleared_i + ZSlack_k \geq LCR_k - \varepsilon_k$

The corresponding shadow price is referred as $SPlcr_k$.

C7) $SSlack_k \leq \max(\, 0\,,\ ZReq_k\ -\ \sum_{i\in G_k} MWCleared_i\ )$

Zonal Prices

The clearing price for each zone k ($ZACP_k$) would be equal to the minimum of the CONE value and the sum of the shadow prices $SPsys,\ SPmin_k, SPmax_k\ , and\ \ SPlcr_k$ for the LP problem.

$$ZACP_k\ =\ \min(CONE_k, SPsys + SPmin_k + SPmax_k + SPlcr_k)$$

Capacity Market Settlement Examples

High Level Clearing Constraints

- Input
  - PRM, Load Forecast, LRR, CIL_z, CEL_z
  - $LCR_z = LCR_z - CIL_z$
  - $PRMR_z = (1 + PRM) * \text{Load Forecast}_z$
  - $LRR_z \geq PRMR_z \longrightarrow LCR_z = \geq PRMR_z - CIL_z$
  - $ZReq_z = \max\{LCR_z, PRMR_z\}$
  - $CONE_z$: maye different for each zone
- Objective
  - $\sum_{i=1}^{m} OfferPrice\ i \times MWClearedi\ +\ \sum_{z=1}^{z}(CONEz\ \times SSLACKz + CONEz\ \times ZSLACKk)$
- Market wide and zonal constraints and shadow prices

$\sum_z \{ZClear_z + SSlack_z\} \geq \sum_z ZReq_z - \varepsilon_o$	($\alpha_{mkt} \geq 0$)	(1)
$ZClear_z + SSlack_z \leq ZReq_z - CEL_z$	($\alpha_{max,z} \leq 0$)	(2)
$ZClear_z + SSlack_z \geq ZReq_z - CIL_z - \varepsilon_k$	($\alpha_{min2,z} \geq 0$)	(3)
$ZClear_z + ZSlack_z \geq LCR_z - \varepsilon_k$	($\alpha_{min1,z} \geq 0$)	(4)

- For export zones, check and resolve to make sure $SSlack_z \leq ZReq_z - ZClear_z$
- Clearing Price

- Market-wide: MACP = α_{mkt}
- Zonal: ZACP = $\alpha_{mkt} + \alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z =}$ MACP + + $\alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z}$
- When both (30 and (4) are violated, $ZACP_z$ may be higher than $CONE_z$. If so, then cap $ZACP_z$ at $CONE_z$.

- Initial Settlement
  - Gen revenue: $\sum_z (\mathrm{ZACP}z * \mathrm{ZClear}z))$
  - Load Payment: $\sum_z (\mathrm{ZACP}z * \mathrm{ZReq}z))$

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FRAP and GMA

- Before the auction, the engineers should have checked the FRAP and GMA data to ensure they are consistent with CIL and CEL;
- All FRAP Gen will be treated as $0 offer and participate the auction clearing;
- All GMA Gen will have an offer and will participate the auction with the offered price;
- After the auction clearing, it will go through all GMAs:
  - If $ACP_{GMA,Gen} \leq ACP_{GMA,load}$, the GMA will be honored and will be excluded from the auction settlement based on ZACP
  - If $ACP_{GMA,Gen} > ACP_{GMA,load}$, the GMA will be not be honored. It will be settled based on ZACP.
- This may cause $\{GMA_{zgen\_to\_exld}-FRAP_{exgne\_to\_zld}\}>CEL_z$ or $\{GMA_{exgen\_to\_zld}-FRAP_{zgen\_to\_exld}\}>PRMP_z - LCR_z$. When this happens, we may pay more to resources than charge from load. The auction clearing engine will check each zone and identify potential issues. If any problem is identified, we will report it and go back to step 1) for proper adjustment of FRAP, CIL and/or CEL to re-run the auction clearing.
- If there is any human error, we may have FRAP in conflict with CIL and/CEL. The engine will not be able to clear all FRAP in this scenario. The engine should report the issue so that FRAP, CIL and/or CEL can be properly adjusted.
- Input validation
  - $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone should be no more than $ZReq_z$-LCR_z: $FRAP_{exgen\_to\_zld} \leq ZReq_z-LCR_z$
  - There is no limitation on $FRAP_{zgen\_to\_exld}$ from generators in zone z to load outside.
    - When there is limitation on CEL_z, $FRAP_{zgen\_to\_exld}$ may not always be cleared from the auction process. However, it will all be treated as cleared at $0 afterwards. In this case, the export binding zone price must be $0.
  - GMA $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone will always be no more than $PRMR_z$-LCR_z: $GMA_{exgen\_to\_zld} \leq ZReq_z-LCR_z$
  - CEL_z will be set so that $GMA_{zgen\_to\_exld}$ from generators can be cleared: $GMA_{zgen\_to\_exld} \leq CEL_z$
- Warning messages from clearing engine for inputs with:
  - $FRAP_{exgen\_to\_zld} > ZReq_z-LCR_z$

– $FRAP_{zgen\_to\_exld} > CEL_z$
– $GMA_{exgen\_to\_zld} > ZReq_z\text{-}LCR_z$
– $GMA_{zgen\_to\_exld} > CEL_z$

- After clearing, GMA and FRAP met the following conditions will be excluded from the auction settlement
  – **The same amount of FRAP Gen or load is excluded if $ACP_{FRAP,Gen} > ACP_{FRAP,load}$**
  – **GMA is honored and excluded if $ACP_{GMA,Gen} < ACP_{GMA,load}$.**
- For GMA and FRAP that are settled outside market (TrGMA, TrFRAP), MISO may have negative revenue if the following conditions are met. Hence the clearing engine will issue ERROR messages when:
  – $TrGMA_{zgen\_to\_exld} - TrFRAP_{exgen\_to\_zld} > CEL_z$
  – $TrGMA_{exgen\_to\_zld} - TrFRAP_{zgen\_to\_exld} > ZReq_z\text{-}LCR_z$
  – $TrFRAP_{zgen\_to\_exld} - TrGMA_{exgen\_to\_zld} > CEL_z$
  – $TrFRAP_{exgen\_to\_zld} - TrGMA_{zgen\_to\_exld} > ZReq_z\text{-}LCR_z$

Settlement Issue Under no Scarcity

- Imbalance under zonal binding

$\sum_z \{ZACP_z*(ZClear_z\text{-}ZReq_z)$

$= \{MACP*\sum_z(ZClear_z\text{-}ZReq_z)\} + \sum_z \{(\alpha_{min1,z} + \alpha_{min2,z}) *(ZClear_z\text{-}ZReq_z)\} + \sum_z \{\alpha_{max,z} *(ZClear_z\text{-}ZReq_z)\}$

– $\{MACP*\sum_z(ZClear_z\text{-}PRMR_z)\}=0$ because

1) If $MACP= \alpha_{mkt}>0$, then (1) is binding. Hence $\sum_z(ZClear_z\text{-}ZReq_z)\}=0$ if $MACP= \alpha_{mkt}>0$.

2) If (1) is not binding, i.e. $\sum_z ZClear_z > \sum_z ZReq_z$, then $MACP=\alpha_{mkt}=0$.

Define $\alpha_{min,z} =\alpha_{min1,z} + \alpha_{min2,z}$

– $\{\alpha_{min,z} *(ZClear_z\text{-}ZReq_z)\} < 0$ when
– (3) and/or (4) is binding, i.e. $ZClear_z = LCR_z$ ➔Import binding $ZACP_z > MACP$
– $\alpha_{min,z}>0$, $\{\alpha_{min,z} *(ZClear_z\text{-}ZReq_z)\}=\alpha_{min,z}* (LCR_z\text{-}ZReq_z) \le 0$
– $\{\alpha_{max} *(ZClear_z\text{-}ZReq_z)\} < 0$ when
– (2) is binding, i.e. $ZClear_z = ZReq_z+ CEL_z$ ➔Export binding $ZACP_z < MACP$
– $\alpha_{max,z}<0$, $\{\alpha_{max,z} *(ZClear_z\text{-}ZReq_z)\}=\alpha_{max,z}* CEL_z \le 0$

Allocation of Imbalance Fund for Import Binding Zones

- For import binding zone
  – Zone with $ZACP_z\text{-}MACP= \alpha_{min,z} >0$

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– Imbalance amount

$\{\alpha_{min,z} *(ZClear_z-ZReq_z)\}=\alpha_{min,z}* \{ LCR_z – ZReq_z\}$

$= \alpha_{min,z} *(LCR_z-ZReq_z)\leq 0$

– This amount should be refunded to load in the zone because the extra load is served by cheaper generation outside

➔Refunding dollar (calculated as part of zone z benefit):

$$\alpha_{min,z} *\{(ZReq_z - TrGMA_{load\ in\ z} - TrFRAP_{load\ in\ z}) - (ZClear_z – TrGMA_{gen\ in\ z} - TrFRAP_{gen\ in\ z})\}$$

This also covers $Zslack_z >0$ and $Sslack_z =0$

➔Amount of load in the zone eligible for refunding:

$ZReq_z$- ($TrGMA_{load\ in\ z}$)-($TrFRAP_{load\ in\ z}$) (where $TrFRAP_{load\ in\ z}$ should most likely be 0)

(Note, may also be allocated to FRAP and GMA per tariff)

- For export binding zone
  - Zone with $ZACP_z$-MACP= $\alpha_{max,z} <0$
  - Imbalance amount

$\{\alpha_{max,z} *(ZClear_z-ZReq_z)\}=\alpha_{max,z}* CEL_z <0$

– This amount should be refunded to load outside the zone because excess load outside is served by cheaper generation from export binding zones

➔For imbalance from export binding zone z1, refunding dollar:

$$-\alpha_{max,z1}* \{(ZClear_{z1} - TrGMA_{gen\ in\ z1} - TrFRAP_{gen\ in\ z1}) -(ZReq_{z1} - TrGMA_{load\ in\ z1}- TrFRAP_{load\ in\ z1})\}$$

➔ It is distributed to load in non export binding zones based on the following logic (calculated as part of zone z benefit):

1) For non-binding zones: $LZ_z=\min\{CEL_z-(ZClear_z-ZReq_z), CIL_z, ZReq_z – LCR_z\}$
2) For each import binding zone, calculate: $LZ_z=ZReq_z -LCR_z$
3) Distribute the imbalance amount proportionally based on LZ_z

➔Amount of load in the zone eligible for refunding:

$ZReq_z$- ($TrGMA_{load\ in\ z}$)-($TrFRAP_{load\ in\ z}$)

(Note, may also be allocated to FRAP per tariff)

Refund under Scarcity ($Sslack_z$>0)

- With zonal CONE and cap ZACP at its CONE, the allocation is more complicated

- If MACP<min(CONEz), all scarcity is considered zonal.
  - $ZACP_z$*$Sslack_z$ is refund to the zone. (if $Zslack_z$ and $Sslack_z$ are both non-zero, price capping will remove the impact from $Zslack_z$)
  - If MACP≥min(CONEz),
  - Zonal scarce (min($Zslack_z$, $Sslack_z$)>0)

$ZACP_z$*min($Zslack_z$, $Sslack_z$) refund to the zone

  - Market-wide constraint can be violated for zonal or market-wide scarcities.
    - Allocate "$\sum_z${$ZACP_z$*[Sslackz -min(Zslackz, Sslackz)]} the same ways as the benefit from export zones, i.e. For non-binding zones based on LZz=min{CELz-(ZClearz-ZReqz), CILz, ZReqz –LCRz} and for import binding zone based on LZ_z=$ZReq_z$-LCR_z.

Amount of load in the zone eligible for refunding:

$ZReq_z$- ($TrGMA_{load\ in\ z}$)-($TrFRAP_{load\ in\ z}$)

(Note, may also be allocated to FRAP per tariff)

Introduction

Flows between the MISO South and Northern MISO Zones is limited by the Regional Directional Transfer Limit per the settlement agreement by MISO, SPP, and the Joint Parties Prior to the 2016-2017 Planning Year, flows between the two MISO Sub-Regional Resource Zones were limited to 1,000 MW. Beginning with the 2016-2017 Planning Year, MISO modified its process to calculate the limit based upon several factors as described previously in this BPM. In order to minimize changes to the auction logic section, all references to 1,000 MW in this Appendix shall represent the directionally SREC and SRIC effective for each Planning Year. The sub-regional power balance constraint is introduced by the transmission capacity limitation of 1000MW between the South Region (Zones 8, 9, and 10 in MISO) and the rest of the MISO system (Zones 1 through 7). This results in a condition that zones 8, 9, and 10 have to be treated both as a group and an individual. At the same time, the rest of the zones (1 through 7) can also be thought of as a group and an individual. The combination of zones has been termed as SuperZone for reference purposes.

Model

Zones 1 to 7 are the Northern MISO Zones. Zones 8, 9,and 10 are the Southern Zones.

Zs is a set of Southern zones and Zn is a set of Northern Zones.

Z is set of all Zones

Constraints Added

SouthExportLimit

$$\sum_{z8to\,z9} ClearedMW + \sum_{Z8toZ9} SystemSlack \leq \sum_{z8,z9} Demand + 1000$$

SouthImportLimit

$$\sum_{z8to\,z9} ClearedMW + \sum_{Z8toZ9} SystemSlack \geq \sum_{z8,z9} Demand - 1000$$

NorthExportLimit

$$\sum_{z1to\,z7} ClearedMW + \sum_{Z1toZ7} SystemSlack \leq \sum_{Z1toZ7} Demand + 1000$$

NorthImportLimit

$$\sum_{z1to\,z7} ClearedMW + \sum_{Z1toZ7} SystemSlack \geq \sum_{Z1toZ7} Demand - 1000$$

Two of the above constraints are redundant but are used for consistency.

Note: The above constraints definitions are for illustration purposes, the implementation in the tool is generic.

Slack

The same slack as the system slack is used for the SuperZone constraints as well. Although a new hierarchy is introduced, the top down relationship hasn't changed.

Pricing

ACP(Z)=SystemDemand.ShadowPrice+ZoneMinClearCons.ShadowPrice(z)+LCRcons. ShadowPrice (z)+ZoneMaxClearCons.ShadowPrice(z)

The above ACP is same as before so no further descriptions on the constraints are given here.

The final ACPs are:

ACP(zs)=ACP(zs)+SouthExportLimit.ShadowPrice+SouthImportLimit.ShadowPrice;

ACP(zn)=ACP(zn)+NorthImportLimit.ShadowPrice+NorthExportLimit.ShadowPrice;

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Additional Post Processing and Notes on Scarcity Pricing

- After clearing the first time, if in the same zone there are multiple offers with prices equal to the $ZACP_z$, the second run will ensure those offers are cleared proportional to their offered MW
- After that, all $0 offers are cleared

Note:

- When there is system shortage, even if all zones meet their local requirements (max(ZReq-CIL,LCR)), the engine has to allocate the system shortage to each zone so that it can solve with different CONE price. The engine allocates the shortage to zones with the lowest CONE first. Each zone is allocated with no more than ZReq-Zclear, i.e. build new resources up to ZReq. For all the zones allocated with shortage, it will solve at its CONE price. All other zones will take the highest CONE of the zone with shortage allocated if nothing else binding.
- It is equivalent to have a system wide demand curve formed as from the lowest CONE to the highest CONE. However, the width of each price segment depends on the solution, i.e. ZReq-ZClear.

Appendix N – Demand and Energy Forecast Characteristics

Forecast Criteria	Coincident Peak Demand and Zonal Coincident Peak Demand Forecasts	Non-coincident Peak Demand Forecast	Energy for Load Forecast
Includes Demand Served by Energy Efficiency Planning Resources	Yes	Yes	Yes
Includes Demand Served by energy efficiency programs	No	No	No
Includes Demand Served by Demand Resources	Yes	Yes	Yes
Includes Demand Served by BTMG Planning Resources	Yes	Yes	Yes
Includes Demand Served by resources not that where not qualified as Planning Resources	Yes	No	No
Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR	No	Yes	Yes
Includes Transmission Losses	No	Yes	Yes
Coincident with reporting Load Serving Entities' system	No	Yes	No
Demand reported at Physical LBA Location	Yes	Yes	Yes
Include Demand from Power Plant Station or Auxiliary Needs	No	No	No

Appendix O – Parties Responsible for Reporting Demand and Energy Forecast

Data	EDC	Retail Choice LSE	Non Retail Choice LSE
MISO Coincident Peak (Total CPF)	No	No	Yes
MISO Coincident Peak (Total NCPF)	No	No	Yes
ZONALZonal Coincident Peak (Total CPF)	No	No	Yes
RC Coincident Peak (Total CPFEDC Area)	NoYes	YesNo	No
RC Coincident Peak (Total NCPF)RC Peak Load Contribution	NoYes	YesNo	No
RC Zonal Coincident Peak (Total CPFEDC Area)	NoYes	YesNo	No
Non-Coincident Peak	Yes	No	Yes
RC Non-Coincident Peak	No	Yes	No
Energy For Load	Yes	No	Yes
Retail Choice (MISO Peak)	Yes	No	No
Retail Choice (Zonal Peak)	Yes	No	No

Appendix P – Zonal Deliverability Benefit *Pro Rata* Allocation

This Appendix is an illustrative example of the ZDB *pro rata* allocation methodology. The results from the Planning Resource Auction for the 2015/2016 Planning Year are used in this example to educate Market Participants. The resulting Auction Clearing Prices illustrated here are different than those settled for the 2015/2016 Planning Year.

Step 1: Subtract PRMR and ZRCs associated with GMAs and ZDC Hedges. For this example, there are no MW associated with GMAs or ZDC Hedges, so the Adjusted PRMR and Adjusted ZRC for each Zone is unchanged from initial totals.

LRZ	ACP	PRMR	ZRC	GMA (MW)	ZDC Hedges (MW)	Adjusted PRMR	Adjusted ZRC
Z1	$3.48	18,320.8	18,495.3	0	0	18,320.8	18,495.3
Z2	$3.48	13,565.8	14,497.2	0	0	13,565.8	14,497.2
Z3	$3.48	9,767.8	9,812.8	0	0	9,767.8	9,812.8
Z4	$150.00	10,419.5	8,851.8	0	0	10,419.5	8,851.8
Z5	$3.48	8,910.3	7,884.6	0	0	8,910.3	7,884.6
Z6	$3.48	19,409.0	19,014.7	0	0	19,409.0	19,014.7
Z7	$3.48	22,677.8	23,514.6	0	0	22,677.8	23,514.6
Z8	$3.29	8,117.8	8,525.9	0	0	8,117.8	8,525.9
Z9	$3.29	25,170.0	25,761.9	0	0	25,170.0	25,761.9

Step 2: Create a Deliverability Benefit Zone (DBZ) for each group of LRZs that have equal ACPs resulting from the same auction constraint. In this example, Zone 4 is a DBZ because the PRA bound on its LCR; Zones 1,2,3,5,6,7 and Zones 8,9 are separate DBZs respectively because the PRA bound on the constraint between the North/Central and South SRRZ

LRZ	ACP	Adjusted PRMR	Adjusted ZRC	DBZ Grouping
Z1	$3.48	18,320.8	18,495.3	Zone A
Z2	$3.48	13,565.8	14,497.2	Zone A
Z3	$3.48	9,767.8	9,812.8	Zone A
Z4	$150.00	10,419.5	8,851.8	Zone B
Z5	$3.48	8,910.3	7,884.6	Zone A
Z6	$3.48	19,409.0	19,014.7	Zone A
Z7	$3.48	22,677.8	23,514.6	Zone A
Z8	$3.29	8,117.8	8,525.9	Zone C

Z9	$3.29	25,170.0	25,761.9	Zone C

Step 3: Determine if each DBZ is a net importer or exporter by subtracting the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. In this example, Zone B is a net importing DBZ and Zones A and C are net exporting DBZs.

DBZ	Sum of Adjusted PRMR	Sum of Adjusted ZRCs	Difference	Result
Zone A	92,651.9	93,219.2	567	Net Exporter
Zone B	10,419.5	8,851.8	-1,567	Net Importer
Zone C	33,288.0	34,288.0	1,000	Net Exporter

The following table contains input and output data of the ZDB *pro rata* allocation methodology. Each additional step below will refer to this table.

	Zone A	Zone B	Zone C	System
FRAP Generation (MW)	0	100	0	100.0
FRRAP Load (MW)	100	0	0	100.0
PRMR (MW)	$92,652	$10,420	$33,288	$136,359
Cleared (including FRAP) (MW)	$93,219	$8,852	$34,288	$136,359
ACP ($/MW-Day)	$3.48	$150.00	$3.29	
ACP x PRMR ($)	$322,427	$1,562,925	$109,518	$1,994,870
ACP x ZRC ($)	$324,403	$1,327,770	$112,808	$1,764,980
Active FRAP ($)	$0	$14,652	$0	$14,652
ZDB Determination		Available ZDB >>		$244,541
Net (Cleared - PRMR) (MW)	568	-1,568	1,000	0.0
Classification	Net Export	Net Import	Net Export	
PRMR for Net Imp (MW)				
Share of Import (%)				
Share of ZDB ($)				
ACP * Net Export ($)	$1,975.60	$0.00	$3,290.00	$5,265.60
SUM of Net Export (MW)				1,568
Wtg. Avg ACP Net Export ($/MW-Day)				$3.36
For Net Import:				
ACP Δ ($/MW-Day)	$0.00	$146.64	$0.00	
ACP Δ * Net Import ($)	$0.00	-$229,889.40	$0.00	-$229,889.40
Plus(+) Active FRAP Allocation ($)	$0.00	-$244,541.40	$0.00	-$244,541.40
ACP reduction/PRMR ($/MW-Day)	$0.00	-$23.47	$0.00	
Net ACP ($/MW-Day)	$3.48	$126.53	$3.29	

Step 4: Calculate the weighted average ACP of all net exporting DBZs.
Zone A: 548 MW exports * $3.48 = $1,975.60
Zone C: 1,000 MW exports * $3.29 = $3,290.00
Wtd. Avg. ACP = ($3,290 + $1,975) / 1,548 = $3.36

Step 5: Calculate the ZDB credit allocation, in dollars, for each net importing DBZ.

Zone B: 1,568 MW import * ($150 - $3.36) = $229,931.52

Step 5a: Calculate the ZDB credit allocation, in dollars, for FRAP contributions.

In this example, there was a qualifying FRAP from Zone B to Zone A for 100 MW. Since the ZRC in Zone B associated with the FRAP is not entitled to PRA revenues, this ZDB is allocated directly back to LSEs in Zone B. The ZDB credit allocation is the FRAP MW amount multiplied by the price difference between the FRAP PRMR and FRAP ZRC.

Zone B: 100 MW FRAP * ($150 - $3.48) = $14,652

Step 5b: Calculate the ZDB credit allocation, in dollars, due to ZDC from FRAP. In this example, there were no ZDC payments from FRAP.

Step 6: Distribute the ZDB credit in each DBZ by dividing ZDB credit by sum of Adjusted PRMR and subtracting that from the initial ACP.

Zone B total ZDB: $229,931.52 + $14,652.00 = $244,583.52

Zone B ACP credit: $244,583.52 / 10,420 MW = $23.47

LRZ 4 is the only LRZ within DBZ Zone B.

LRZ 4 Net ACP: $150.00 - $23.47 = $126.53

Business Title

MISO

Title	Version	Reference #
BPM-011-r16 Resource Adequacy	16	438

Date Created	Date Submitted
11/09/2015	07/29/2016

Date Approved	Publication Date
08/22/2016	08/22/2016

Next Annual Review Date	Review Interval
08/22/2017	12 month(s)

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Approvers

MISO: Harmon, John (Mgr Resource Adequacy)	Accepted (08/22/2016 9:56 AM)
MISO: Krouse, Jacob (Corporate Counsel)	Accepted (08/22/2016 9:54 AM)
MISO: Gatekeeper	
MISO: DeMaire, Sherry (Spec I Controls & Process Assurance)	Accepted(08/22/2016 12:53 PM)

[redacted]

From: Parsley, Marlene
Sent: Tuesday, June 27, 2017 4:06 PM
To: Brad Bickett ([redacted])
Cc: Eacret, Mark
Subject: FW: planning reserve margin requirement - HMP&L
Attachments: Henderson PRMR calculation 6-27-17.docx; 2005-2015 Historical Peak Dates and Times.pdf; Peak Forecasting Methodology Review Whitepaper.pdf; HMPL Load Forecast worksheet revised 3-31-16 with monthly data.pdf

Hello, Brad
It appears you're using a similar, but not identical methodology that we used for calculating HMPL's coincidence factor. I've provided some extra information attached and below to show what I mean. Don't hesitate to reach out for more clarification.

Marlene

I notice 2 major differences when comparing your calculation in the "Henderson PRMR calculation 6-27-17.docx" to the one Big Rivers Supplied in our presentation (copied below along with a few pertinent highlights):

1. 2017 Peak Forecast
   a. HMPL used the one from January, 2017 (108 MW)
   b. Big Rivers used the one in effect at MISO's October 31, 2016 submission date (see attached "HMPL Load Forecast worksheet revised 3-31-16 with monthly data.pdf") (109 MW)
2. Time period for calculating coincidence factor
   a. HMPL used one year (2016)
   b. Big Rivers used the average of 2011-2015 (see table below for our calc.)

The following table shows the values our contractor (GDS) used to compute the coincidence factors for HMPL for Planning Year 2017/18. CP demands represent the average load at the four MISO and MISO/Zone6 peak hours each year. FYI: While our contractor calculated and included in the table a coincidence factor for MISO Zone 6, only the CP with MISO is used for calculating the Planning Reserve Margin Requirement.

HMPL

	1HR Peak	CP with MISO	CF	CP with Zone 6	CF
2011	113	109.1	0.965	109.3	0.967
2012	115	106.5	0.926	107.3	0.933
2013	108	106.0	0.981	105.3	0.975
2014	108	105.3	0.975	104.5	0.968
2015	109	98.8	0.906	103.6	0.950
2016	107				
			0.951		0.959

For your reference, attached are the Historical Peak Dates and Times supplied on MISO's website, as well as a Whitepaper describing what MISO looks for when they review a forecast submitted by an LSE (see page 7 of 14, as well as Appendix A on page 11/14). For the PY 17/18 forecast, Big Rivers used the same forecast methodology that was randomly sampled for review by MISO (I believe it was for PY 13/14) and our forecast was deemed "Acceptable" at that time.

Copied from the previous report Big Rivers supplied to HMPL:

Load and Resource Examples from PY 2017/18:
HMPL's Planning Year 2017/18 Load Obligation:

Annually, Big Rivers must submit a Coincident Peak Demand forecast for the upcoming planning year for loads at Commercial Pricing Nodes by November 1 of the year prior to the planning year. Because HMPL Load is represented within the Big Rivers load commercial pricing node (BREC.BREC), Henderson load is included in the Big Rivers' coincident peak Demand. This year, Big Rivers contracted with GDS to determine the coincident peak demand forecast, and additionally requested a coincidence factor for HMPL load. The HMPL load forecast was determined to be coincident to MISO peak by a factor of .951. Applying the .951 coincidence factor to HMPL's forecasted July 2017 peak of 109 MW (per the forecast that was effective at the November 1, 2016 Peak Demand Forecast due date), the coincident peak load for HMPL is 103.7 MW.

So, for Planning Year 2017/18 the HMPL Planning Reserve Margin Requirement calculation is:

Coincident Peak MW *(1 + Transmission Losses) * (1 +PRM)
Coincident Peak MW = 103.7 MW
Transmission Losses = 2.2%
PRM =7.8%
Requirement = Coincident Peak MW + Transmission Losses + PRMR
Requirement = 103.7 MW * 102.2% *107.8%
Requirement = 114.2 MW

Marlene Parsley
Director, Resources and Forecasting
Big Rivers Electric Corporation
[redacted]

[redacted]

From: Brad Bickett [[redacted]]
Sent: Tuesday, June 27, 2017 12:33 PM
To: Parsley, Marlene
Cc: Eacret, Mark J
Subject: planning reserve margin requirement - HMP&L

Marlene,

Thanks again for your help on this resource adequacy topic. I will probably be reaching out to you and/or MISO with additional questions. After looking over the information provided and our data, I attached for your review my quick version of the MISO Planning Reserve Margin Requirement calculation for HMP&L during this current Planning Year.

Brad

Planning Reserve Margin Requirement (PRMR) calculation for HMP&L - Planning Year 2017/18:

MISO peak for 2016 = 8/11/2016 HE16 EST (equal to CDT)

HMP&L load at MISO peak hour = 99 MW

HMPL annual peak (2016) = 107 MW

HMP&L coincidence factor = .925

HMP&L forecasted peak for August, 2017 (per HMP&L forecast from January, 2017) = 108MW

Coincident peak load for HMP&L = 99.9 MW

MISO Transmission Loss target = 2.2%

MISO Planning Reserve Margin (PRM) target = 7.8%

PRMR = Coincident Peak MW *(1 + Transmission Losses) * (1+PRM)

PRMR = 99.9 MW * 1.022 * 1.078

PRMR = 110 MW

MISO PEAK DATES & TIMES

For the Period 2005 - 2015, June – September

	DATE	HE
	June 22, 2015	17
➲	July 28, 2015	16
	August 14, 2015	16
	September 1, 2015	17
	June 17, 2014	17
➲	July 22, 2014	17
	August 25, 2014	15
	September 4, 2014	16
	June 27, 2013	15
➲	July 18, 2013	16
	August 29, 2013	16
	September 10, 2013	16
	June 28, 2012	17
➲	July 23, 2012	16
	August 3, 2012	16
	September 4, 2012	17
	June 7, 2011	17
➲	July 20, 2011	17
	August 2, 2011	16
	September 1, 2011	16
	June 22, 2010	17
	July 23, 2010	16
➲	August 10, 2010	16
	September 1, 2010	16

	DATE	HE
➲	June 25, 2009	15
	July 10, 2009	16
	August 10, 2009	15
	September 14, 2009	16
	June 26, 2008	15
➲	July 29, 2008	17
	August 1, 2008	16
	September 2, 2008	16
	June 26, 2007	16
	July 31, 2007	17
➲	August 8, 2007	16
	September 5, 2007	16
	June 22, 2006	15
➲	July 31, 2006	16
	August 2, 2006	16
	September 7, 2006	16
	June 27, 2005	15
➲	July 25, 2005	15
	August 3, 2005	16
	September 12, 2005	16

Notes:

1. HE = Hour-ending, MISO time (Eastern Standard year-round)
2. Hourly Integrated System Peaks
3. ➲ Indicates MISO Peak/Summer Peak, to be used for GVTC temperature corrections

Peak Forecasting Methodology Review

Introduction

This document provides information intended to assist those developing annual forecasts of the peak demand of a Load Serving Entity [1] (LSE) coincident with MISO's summer (annual) peak demand, for MISO's use in resource adequacy. There are many good texts and articles concerning peak forecasting, and the reader is encouraged to review the literature. Nonetheless, a concise review of the underlying principles and approaches that are appropriate for the annual, longer-term peak forecasting requirements facing LSEs within MISO seems warranted. At the outset, we wish to make clear that this document is intended primarily to assist, not prescribe, while at the same time delineating certain courses that are preferable and those that are unacceptable for the task at hand.

A definition of what is meant by "coincident peak demand" may be useful. Unless specifically indicated to the contrary, "coincident peak demand" shall be understood to be the peak demand of an LSE at the time of MISO's summer (annual) peak, that is, MISO's largest peak when viewed as a single entity.

General Approach to Applied Research

Peak forecasting belongs to a larger class of studies known as applied research. The following outline briefly describes the major steps necessary in any professional applied research endeavor.

Review the Literature

The first step in any applied research is to obtain a good theoretical understanding of the topic under study. Reinventing the wheel should be avoided, if only on efficiency grounds. This necessary first step provides the analyst with a grasp of how the topic has been approached in the past, what the pitfalls and successes have been, and may suggest ideas for current or future analysis. Whether the analyst ultimately decides to follow an already well-developed method or to pursue a new approach, a good theoretical underpinning will prevent many mistakes and difficulties in later steps.

[1] In retail choice states, the entity responsible for electricity distribution (EDC) is the entity that will develop the required peak forecast submissions for their entire distribution service area, including customers served by one or more LSEs within the overall service territory of the EDC. Future references in this paper to LSEs in this context should be understood to include these EDCs as well.
On a related note, one or more entities (e.g. municipalities or cooperatives), which provide electric distribution services but purchase some or all of their power requirements at wholesale, are considered "EDCs" for peak forecasting purposes. Such entities may transfer the obligation of providing peak forecasts to the distribution utility serving the surrounding area, supplying MISO with appropriate notice and documentation.

Develop the Theoretical Model

Developing the theoretical model includes several related steps. The two most important steps are the selection of the variables and the functional (mathematical) form of their inclusion.

First, the independent or explanatory variables must be selected, including how they should be measured. Theory should indicate a large number of factors that could plausibly be related to the variable under study. Selecting the important variables from theory is a large part of the art of modeling or forecasting. Omitting an important variable causes significant distortions to the results, while omitting an unimportant or minor factor results in few, if any, difficulties.

Second, the functional form (e.g. linear) of the variables must be chosen. Here, theory is often less of a guide, and more latitude is given to the analyst. However, the selection of any functional form carries with it certain assumptions or restrictions that the analyst must carefully weigh to ensure that reasonable results are obtained.

Collect, Inspect, and Clean the Data

This step may appear to be a simple exercise, but it often makes the difference between good results and bad. Data should be collected from reliable sources, well-documented and well-understood. Many empirical mistakes can be traced back to a lack of understanding regarding the actual dataset employed in the analysis. Inspecting and cleaning the data to ensure accuracy is a relatively thankless task, but should not be skipped or underrated. Using a large quantity of data in the hopes that this somehow acts to counter-act low quality data is a sure route to poor results.

Estimate and Evaluate Equation

This step includes the primary analysis of the data, typically utilizing ordinary least squares or other mathematical techniques suitable to the analytical approach selected. Results should be evaluated against both theory and common sense; there is no substitute for the analyst's ability to judge whether the results obtained are "reasonable".

Document Results

Long hours of literature review, careful model development, attention to the details of obtaining reliable data, and a skilled analytical effort can be rendered worthless if not appropriately documented. Copying statistical results from computer programs and providing reams of data are neither sufficient nor desirable documentation. The desired product includes a clear and concisely written document that outlines and summarizes the research effort in its entirety. Sufficient detail should be provided to allow the reader to understand the path followed by the analyst, the quantitative and qualitative results obtained, and any conclusions reached – all expressed in a comprehensible and transparent manner. Supporting data and statistical results should be available (e.g. in appendices) such that the reader could duplicate the results described.

Specific documentation requirements are provided in the Resource Adequacy BPM. For a list of example documents, please see the section

APPENDIX A: FORECAST DOCUMENTATION EXAMPLE LIST.

Qualities of a Good Forecasting System

Having covered the general requirements of a well-performed applied research effort, we turn now to the narrower task of describing the characteristics desirable in a good forecasting system.

Much of the following was taken from a booklet prepared for the Edison Electric Institute by Charles River Associates, **A GUIDE TO ELECTRICITY FORECASTING METHODOLOGY**. While the publication is, from our current perspective, "old", its observations, comments, and conclusions remain valid.

A "good" peak forecasting system has certain general qualities that distinguish it from other systems. These qualities provide a useful basis for understanding why "good" forecasting systems outperform others over time.

Understandability

If users understand the rationale of a forecast, they can appraise the uncertainty of the forecast, and they will know when to revise the forecast in light of changing circumstances. *This characteristic is particularly important in planning.*

Credibility

The forecast will be reviewed by top management, the financial community, and regulators. The forecast should be credible to these audiences. Included under the label of "credibility", we would include *replication* (the same results should be achieved by another analyst following the same procedures) and *defensibility* (the forecast should withstand reasonable questions regarding its development and results).

Accuracy

The more accurate a forecast is, the better are the decisions that depend upon it. Inaccurate forecasts lead to too much or too little capacity and can be very costly. Note that accuracy can be separated into two distinct issues: first, how accurate is the forecast when the conditional inputs are accurate, and second, how accurate is the forecast given the conditional inputs used at the time the forecast was prepared and submitted? Answers to these questions will indicate whether additional work is required on the underlying model or on the process used to generate the conditional inputs.

Reasonable Cost

Forecasts cost money, time and effort. Added expense must purchase added accuracy, flexibility, or insight.

Maintainability

A sophisticated forecasting system requires ample staff resources and technical skills for maintenance. Choice of a forecasting system must include a commitment to the resources necessary to maintain it and avoid systems the utility will be unable or unwilling to maintain.

Adaptability

Forecasts are subject to change as a result of changing energy prices, the economy, and other factors. The forecasting system should be able to generate new forecasts in response to changing conditions. Forecasting models that can examine "what if" issues and evaluate hypothetical scenarios can help forecasters (and forecast users) respond to changing conditions.

Considerations in Forecast Development

Forecasting involves issues that the analyst must resolve if the forecast is to be effective. While the following list is not completely inclusive, it does illustrate the primary issues that require careful consideration.

Utilizing Available Data

Ideal data for forecasting are never fully available. Forecasting systems must be designed to rely on data that can be assembled at reasonable cost, in a reasonable time frame.

Acknowledging Uncertainty

Load forecasts are inherently uncertain. Forecast users need to understand the range of error. The analyst needs to present quantitative and qualitative measures of forecast uncertainty and to understand the sources of forecast error as they relate to key factors that influence electricity demand. The forecaster's understanding of the sources of uncertainty needs to be clearly conveyed to forecast users in a way that allows for their lack of familiarity with the forecast development process.

Reflecting Key Factors

Load growth reflects the influence of electricity prices, economic growth, population, and other key factors. Changes in these factors can lead to forecasting errors if not appropriately considered in the forecast modeling process.

Conditional Forecasts

Forecasts are "conditional" upon forecast model assumptions and projected values of key demand influencing factors. Conditional forecasting is important for examining the sources of uncertainty by relating forecasts explicitly to alternative values of key factors. It is also useful in examining historical experience. For example, a forecast based on normal weather may be inaccurate because of extreme weather but otherwise accurate.

Accommodating Change

Changing customer behavior, new uses, conservation programs, and other changes affect the accuracy of forecasts. Forecast must explicitly or implicitly allow for changes.

Preventing Double Counting

Forecasted reduction in energy use or peak loads from conservation or load management should not double count the impact of multiple programs or increased electricity prices.

Integrating Energy and Peak Forecasting

Consistency of energy sales, load shape, and peak load forecasts with one another must be reconciled with the accuracy of each forecast.

Selecting the Model for the Forecast Period

A forecasting system that produces accuracy for a 1-year forecast is not necessarily the best system for longer-term forecasting. The design of the forecasting system involves a choice of what forecast horizon is of primary interest.

Optimizing the Level of Aggregation

Disaggregating forecast models by end use, timing of loads, geography, or other factors can improve forecast accuracy or the usefulness of forecasts in planning, but it increases model complexity and makes models more difficult to maintain, understand, and explain to forecast users. The best forecasting systems concentrate detail where it is most useful for planning or improves accuracy.

Consistency

Forecasts of population, income, electricity rates and fuel prices, industrial production, and other key variables must be consistent with one another and with comparable assumptions used in utility planning. This consideration is acknowledged by requiring utilities to use the same forecast methods as those they use in their other regulatory planning submissions.

Forecasting Methodologies

There are many methods available to analysts when preparing a peak demand forecast. This section attempts to provide some guidance in distinguishing those methods that are acceptable to MISO in regards to forecasts submitted for resource adequacy purposes.

A word of caution or explanation is required to understand this section properly. Simply using an “acceptable” methodology will not guarantee blind acceptance of the peak forecast submitted. Within the broad class descriptions provided below, there exists the possibility of selecting an appropriate method but executing it poorly. For example, one can imagine an econometric model in which the coincident peak demand is forecast on the basis of sunspots. Such a model comes from an “acceptable” method (econometrics) and uses an “explanatory” variable (sunspots). Nevertheless, the model is unsuitable and would be rejected, as the proposed relationship is farcical. Another example would be a well-designed model that proposes to use an inappropriate input value in the calculation of the coincident peak. MISO will work with its members, particularly LSEs responsible for peak forecast preparation, through workshops, stakeholder presentations, and other forums in an effort to minimize potential misunderstandings regarding acceptability.

Acceptable List

The following list of forecast methods may not specifically include all potentially acceptable methods, but it does clearly indicate the basic approaches desired. To our knowledge, these methods are employed by all utilities within MISO’s footprint for load forecasts submitted to regulators for planning purposes. If your particular forecasting method does not appear to fall within one of the categories listed, please contact MISO staff so that together we may review your approach to peak forecasting.

End-Use

End-use forecasts are based upon an enumeration of electricity-using activities (“end-uses”) and specification of the level of use for each. While end-use forecasting is widely used by electric utilities, it has been criticized for several major shortcomings, including a tendency to under-forecast by missing new devices or activities and the use of engineering-based estimates that do not conform to actual consumer usage patterns or rates.

Econometric

Econometric forecasts are based upon statistically estimated forecasting equations linking electricity use to key variables such as electricity prices, fuel prices, customer income, commercial and industrial activity, weather, and major appliance stocks. Econometrics is also widely used by electric utilities. Criticisms of econometrics include its inability to directly account for certain specific programs, activities, or regulated requirements, either already in-place or forecasted. Econometrics is also used to estimate certain data used with end-use models.

Hybrid

A hybrid forecasting system employs an end-use structure embedded in an overall model with econometric estimation of some equations, particularly to estimate appliance usage, appliance stocks, and price impacts. Hybrid methods are also widely used by utilities.

Unacceptable List

The unifying trait of the methods found in the following “unacceptable” list is the lack of key factors that “explain” the forecast. Each of the following methods is essentially a “black box” that proposes to forecast peak demand primarily, if not exclusively, without direct reference to causal factors.[2] It is this lack of conditional methodology that sets them apart from the preceding list.

Time Trend

A time trend forecast is an extrapolation of historical trend. This method was widely used by utilities until its drawbacks became evident in the 1970s.

Autoregressive Approaches

Any statistical extrapolation of historical trend using only data from the series to be forecast is unacceptable as the primary forecasting technique. A time trend forecast can be viewed as an extremely simple autoregressive approach. The most recognized names in such forecasting are Box and Jenkins, co-authors of widely used methods in this field. Note that this approach may be appropriate for certain smaller load customer classifications for which explanatory analysis would be inefficiently expensive or time-consuming. In addition, autoregressive methods may be employed as part of an econometric approach to describe certain error patterns that remain even after the analyst has attempted alternative corrective approaches.

[2] These forecasting methods, however, may be valid under other circumstances. Over longer horizons, causal explanation of the forecast becomes more critical.

Informed Opinion

A forecast based on informed opinion is determined from expert judgment. This method is sometimes used to predict large industrial customer use, or new uses of electricity. The primary difficulties in using informed opinion are the lack of quantitative support, the inability to examine alternatives, and the qualifications of the "expert" making the forecast. Informed opinion should be used, in our judgment, to design a forecasting system that quantifies the "expert" knowledge in a way that allows for examination by outside parties.

Review Approach

MISO staff will review a sample of submitted forecasts each year. In that review, the **Considerations in Forecast Development** along with the following elements will be examined:

- Does the forecast approach follow appropriate theoretical guidelines?
- Does the forecast approach include appropriate causal variables?
- Is the overall "fit" of the equation(s) presented reasonable?
- Are the signs (±) on each coefficient in agreement with the underlying theory?
- What is the statistical confidence with which the coefficients are distinct from zero?
- Are coefficient elasticities or impacts in reasonable agreement with expectations?
- Are the input values used in the calculation consistent with the 50/50 approach?
- Do the equations suffer from any econometric issues, such as omitted variables, irrelevant variables, inappropriate functional form, multicollinearity, serial correlation, or heteroskedasticity?
- Are supporting studies, relied upon for inputs, relevant and up-to-date?
- Are intermediate results developed from sample data that is statistically reliable?

Given the variety of specific forecasting approaches and potential variations, it is not realistic to attempt an all-inclusive set of prescribed conditions that every forecast must meet in a programmatic, predetermined fashion. *The intent of the forecast review process is to determine whether the approach used and the results obtained are reasonably derived from causal factors employed, using a scientific and reproducible approach, and based on 50/50 conditions.* Forecasts prepared that meet these conditions will be approved.

There are three possible outcomes of the review process:

1. The forecast is acceptable,
2. The forecast would be acceptable given certain modifications, and
3. The forecast is unacceptable.

Forecasts falling in the first category will be approved in their present form. Forecasts falling in the second category will be returned to the forecasting entity with complete instructions for modifying the forecast such that it would be acceptable to MISO. Provided that the changes are made appropriately and submitted sufficiently prior to the forecast deadline for final review, the revised forecast will be approved. Forecasts in the second category which are not appropriately revised and forecasts in the third category will be rejected. In such cases, MISO staff will prepare the necessary forecast. Forecasting entities for which forecasts must be prepared by MISO may automatically have their forecasts reviewed in the following year.

General Approach to Coincident Peak Forecast

This section describes the desired general approach to determining the coincident peak forecast. MISO expects LSEs to begin the process by completing the forecast of non-coincident peaks and net energy for load in the manner suitable for their regulatory governing body. These typically well-developed and scrutinized forecasts will form the basis of the desired approach.

Starting from the most recently available non-coincident peak forecast prepared, using the procedures used for retail regulators (RERRAs), the forecast of the MISO coincidence factor should be developed. This development should focus on the relationship between the LSE's monthly non-coincident peak demands and the LSE's demands at the time of MISO's monthly peaks. Historical data for the summer months (June – September) should be used, concentrating on data series (variables) that are likely to explain the coincidence relationship. The expectation is that weather will play the dominant role, although other factors may be important. Nevertheless, the precise way in which weather plays its role may differ among LSEs, based on geographic location, size, and other unique issues. The incorporation of local, detailed knowledge of customer usage patterns is precisely the sort of enhancement that is sought from this procedure.

Once the coincident relationship has been identified and estimated, the coincident peak forecast may be developed by inserting the "50/50" values required by the model described above. An explanation of the derivation of these input values should be submitted with the forecast.

While the approach outlined above is the expected course, entities responsible for providing the coincident peak forecast are free to discuss alternative approaches with MISO staff. The goal of coincident peak forecasting is to obtain accurate estimates of each entity's coincident peak – not to blindly follow a script that could be improved upon. At the same time, this open approach should not be construed as an invitation to follow a course that does not meet the standards of good forecasting, replicable studies, and the scientific approach generally.

Specific Approaches to Coincidence Factor Modeling

This section provides some broad comments on how the coincidence factor model might be constructed. As stated earlier, it is not our intention to provide any specific approach to the problem for several reasons. First, we believe that providing a specific approach would serve to depress, if not eliminate, independent thought and potentially innovative solutions. Each utility is unique, and each is free to discover a unique solution to coincident peak forecasting, within certain broadly framed constraints as already described. Second, we believe that each utility has access to specific local information and data that would be difficult, *a priori*, to specify or locate. For example, a utility may be aware of a large industrial customer that does not operate during certain relevant summer hours. Such a customer would contribute nothing to the summer coincident peak. Approaches applied to aggregate data would not, generally, incorporate these kinds of local knowledge.

Nevertheless, a few broad comments and observations regarding coincident peak forecasting and coincidence factors would seem warranted. Since we are assuming that a monthly non-coincident peak forecast [3] is available, our comments will focus on the transition to the annual coincident peak from those values.

The relationship between a coincident peak (CP) and a non-coincident peak (NCP) is known as a coincidence factor. Where both the CP and the NCP come from the same time period (e.g. calendar month), the coincidence factor is constrained to lie between zero and one.

The factors that determine the CP would generally be expected to be those that determine the NCP, with a few exceptions. This is helpful; to the extent that the causal variable values are unchanged between the CP and NCP, they need not be incorporated into the coincidence factor model. The primary exception would be weather, since expectations regarding the CP are likely to be different from that of the NCP. Another difference might be specific customer usage patterns. Other differences may exist, depending upon the modeling approach used to estimate the system's NCP values.

Special Issues

The following issues affect the forecast of coincident peak in some unique or unusual way that should be expressly considered and documented.

LMR: Demand Resources & Behind the Meter Generation

Load Modifying Resources (LMRs), comprised of demand resources and behind the meter generation, can be used to reduce demand, typically during peak conditions. Since both of these resources may receive specific planning credit for their contribution to meeting the planning reserve margin requirements, it is critical that the reductions (or contributions) are appropriately reflected in the modeling and reporting.

Reductions associated with LMRs should be added back to the historical load values prior to the analysis. Once the analysis has determined the relationship between NCPs and CPs, the CP exclusive of LMR reductions can be calculated. LMRs' reduction of the coincident peak will be separately credited through the resource adequacy process, and should not be subtracted from the CP forecast. The amount "added back" should include the appropriate "gross up" for losses, from the resource's measurement point to the normal measurement level of load for the LSE. For example, if the actual recorded coincident peak of the LSE is 100 MW, but during that hour LMRs were reducing the load by 5 MW (measured at the resources), and the loss factor from that measurement point to the LSE's measurement point is 7%, then the total historical coincident peak for the LSE should be 100 + 5/0.93 = 105.4 MW. The specific details of the calculations aside, the important point is to determine the load that would have been recorded in the absence of the LMR reductions.

[3] By "non-coincident peak forecast" we mean the peak demand of the LSE when considered as a single entity.

MISO recognizes that there may be a difference between the expected contribution of an LMR towards reducing the expected coincident peak and the amount of reduction actually experienced at any given historical coincident peak. Such differences may be largely attributable to weather conditions: for example, actual reductions will vary with actual weather, while forecasts are based on normal weather conditions.

Demand Response Resources (DRR)

Demand Response Resources should be treated in a manner analogous to LMRs. See above.

Energy Efficiency Resources (EER)

Energy Efficiency Resources should be treated in a manner analogous to LMRs. See above. The approach to resource adequacy limits EER capacity credits to four years, following which such EER would become embedded in the forecast. Once an EER is no longer registered with MISO, the historical reductions of such EER should be incorporated directly in the historical data and in resource adequacy forecasts provided to MISO.

Future Resources (LMR, DRR, EER)

Certain resources may not have existed at the time of MISO's summer (annual) peak. The estimated future coincident peak demand of such resources should, of course, be included in the coincident peak demand forecast for the LSE, so that any future *reduction* may be appropriately credited towards meeting that coincident peak.

Concluding Remarks

The approach proposed by MISO in the area of coincident peak forecasting is to begin, where possible, with load forecasts already routinely prepared for other regulatory and financial forums. By leveraging these forecasts, the additional expense related to coincident peak forecasts is minimized, and consistency with forecasts already used, reviewed, or widely disseminated is maintained. Only the final step, the conversion from a non-coincident peak forecast to a peak forecast coincident with MISO's footprint, is necessary.

In addition to minimizing the additional expense and effort required of its members, the proposed approach to coincident peak forecasting should reduce the expense incurred by MISO in its review process. Rather than requiring a complete review of the entire forecasting process, MISO can perform a much more limited review of the non-coincident peak development, and concentrate its efforts in the review of the final coincident peak step of the process.

MISO expects that this final conversion step, the development of a coincidence factor, will consist of determining the relationship between a utility's non-coincident (system) peak and the utility's peak at the time of MISO's summer (annual) peak. Given the nature of peak demand, this relationship will be primarily determined by differences related to weather conditions, and specific load characteristics of each utility.

§

APPENDIX A: FORECAST DOCUMENTATION EXAMPLE LIST

- Narrative summary of non-coincident peak forecast methodology
- Narrative summary of net energy for load forecast methodology
- Narrative explanation of coincident peak forecast methodology
- Description of equations including:
  - Variables (data series) used
    - Full names
    - Abbreviations used
    - Description of variable
    - Data source
    - Links to data used in development
  - Statistical output for estimations (as typically provided by software)
    - adjusted R^2
    - coefficient values
    - standard errors of coefficients
    - t-statistics of coefficients
    - standard error of regression
    - Durbin-Watson statistic
    - mean of dependent variable values used
    - standard deviation of dependent variable values used
    - time span of data employed in estimation
  - Graphical depiction of residuals
  - Tabular presentation of residuals
  - Graphical depiction of fitted and actual dependent variable values
  - Description of any adjustments made to data employed in equation
- Non-statistical assessment of the reasonableness of the estimated coefficients
- Description of process used to determine forecast values used for independent (“explanatory”) variables
- Narrative description of any load-shape studies employed
  - Description of sample customers
    - Geographical location
    - Customer class / type
    - Sample selection criteria
  - Duration and time-period of sample data employed
  - Links to complete study reports
- Provision of supporting studies used to justify end-use parameters
- Provision of supporting materials used to benchmark end-use results
- Name, phone number, and e-mail address of contact individual knowledgeable of forecast preparation details
- One-page summary of coincidence factor employed or resulting from coincident peak forecast methodology, including high-level schematic of general approach used

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APPENDIX B: EXAMPLE COINCIDENT PEAK FORECAST DEVELOPMENT

The data, methods, and results shown below are an *example* of how an LSE might calculate its coincident peak demand. The data is fictitious, and the method is simply one approach to the problem.

DATA

Month	Coincidence Factor	Temperature at Coincident Peak
Jun-05	0.910	85.4
Jul-05	0.952	89.4
Aug-05	0.970	91.1
Sep-05	0.950	86.9
Jun-06	0.979	94.3
Jul-06	1.000	99.6
Aug-06	0.994	98.4
Sep-06	0.936	89.5
Jun-07	0.962	94.0
Jul-07	0.920	89.0
Aug-07	0.970	93.5
Sep-07	0.920	85.1
Jun-08	0.952	89.7
Jul-08	0.999	100.4
Aug-08	0.982	95.4
Sep-08	0.960	90.0
Jun-09	0.925	82.3
Jul-09	0.930	84.4
Aug-09	0.930	86.0
Sep-09	0.900	81.7
Jun-10	0.969	95.5
Jul-10	0.970	98.3
Aug-10	0.981	97.0
Sep-10	0.948	91.0
Jun-11	0.910	79.0
Jul-11	0.930	82.4
Aug-11	0.950	88.8
Sep-11	0.900	80.1
Jun-12	0.940	86.0
Jul-12	0.950	90.7
Aug-12	0.960	92.0
Sep-12	0.890	78.0

Analysis

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9394
R Square	0.8824
Adjusted R Square	0.8785
Standard Error	0.010
Observations	32

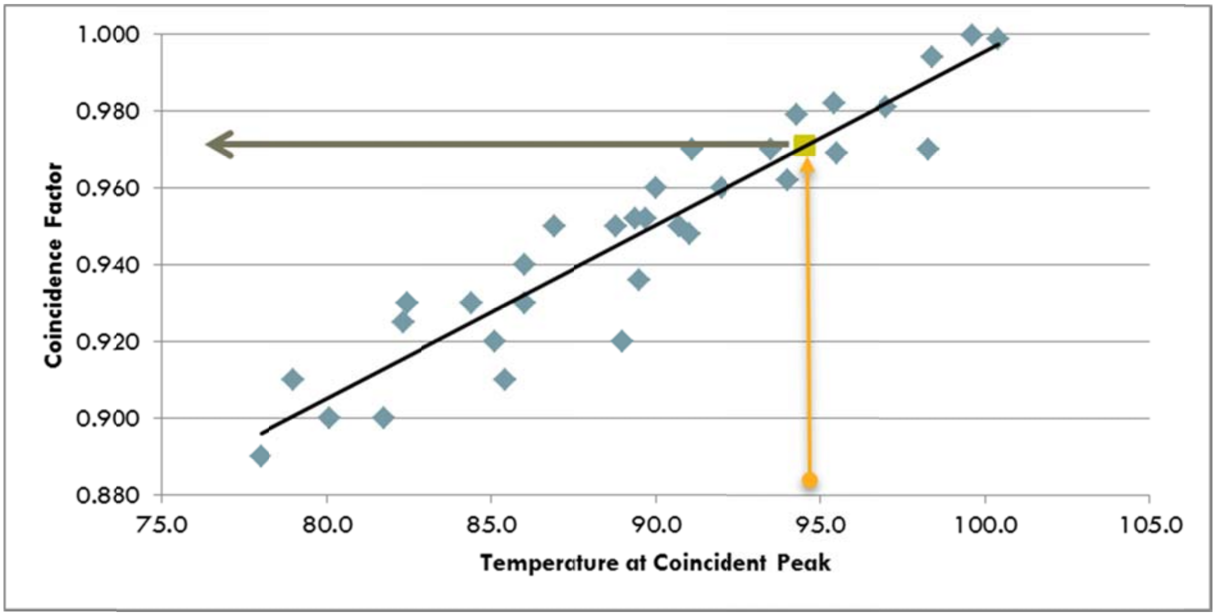
ANOVA

	df	*SS*	*MS*	*F*	*ignificance F*
Regression	1	0.023962345	0.02396235	225.1135	1.74E-15
Residual	30	0.003193369	0.00010645		
Total	31	0.027155714			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.5420	0.0271	19.98	6.93E-19	0.4866	0.5974
Temperature	0.0045	0.0003	15.00	1.74E-15	0.0039	0.0052

RESIDUAL OUTPUT

Observation	*Predicted Coincidence Factor*	*Residuals*
1	0.929	-0.019
2	0.948	0.004
3	0.955	0.015
4	0.936	0.014
5	0.970	0.009
6	0.994	0.006
7	0.988	0.006
8	0.948	-0.012
9	0.968	-0.006
10	0.946	-0.026
11	0.966	0.004
12	0.928	-0.008
13	0.949	0.003
14	0.997	0.001
15	0.975	0.007
16	0.950	0.010
17	0.915	0.010
18	0.925	0.005
19	0.932	-0.002
20	0.913	-0.013
21	0.975	-0.006
22	0.988	-0.018
23	0.982	-0.001
24	0.955	-0.007
25	0.900	0.010
26	0.916	0.014
27	0.945	0.005
28	0.905	-0.005
29	0.932	0.008
30	0.953	-0.003
31	0.959	0.001
32	0.896	-0.006



RESULTS

Assume that the expected temperature at the time of the Coincident Peak is 94.5 degrees.[4] Using this value as the input, the regression analysis (above) then provides the expected coincidence factor, as shown below. Finally, peak demands at the time of MISO's peak can be determined by using this coincidence factor and the non-coincident peak forecast values.[5]

Expected Temperature		
at time of Coincident Peak:		94.5
Expected Coincidence Factor:		0.971
YEAR	NCP Forecast	Coincident Peak Forecast
2014	164,468	159,698
2015	166,387	161,562
2016	168,325	163,444

§

[4] This expectation would be developed in a separate analysis.
[5] Again, these non-coincident peak forecast values would be determined in a separate procedure.

Actual	
Forecasted	

HMP&L Load Forecast - (Udated 3-31-16)

	Energy (MWH)	Growth per Year	Summer Peak (MW)	Growth per Year	Winter Peak (MW)	Growth per Year
2013	617,149		108		93	
2014	639,296	3.6%	108	0.0%	102	9.7%
2015	625,083	-2.2%	109	0.9%	100	-2.0%
2016	623,229	-0.3%	109	-0.1%	94	-6.0%
2017	626,345	0.5%	109	0.5%	99	5.5%
2018	629,477	0.5%	110	0.5%	100	0.5%
2019	632,624	0.5%	111	0.5%	100	0.5%
2020	635,787	0.5%	111	0.5%	101	0.5%
2021	642,145	1.0%	112	1.0%	102	1.0%
2022	648,567	1.0%	113	1.0%	103	1.0%
2023	655,052	1.0%	114	1.0%	104	1.0%
2024	661,603	1.0%	116	1.0%	105	1.0%
2025	668,219	1.0%	117	1.0%	106	1.0%
2026	674,901	1.0%	118	1.0%	107	1.0%
2027	681,650	1.0%	119	1.0%	108	1.0%
2028	688,467	1.0%	120	1.0%	109	1.0%
2029	695,351	1.0%	121	1.0%	110	1.0%
2030	702,305	1.0%	123	1.0%	111	1.0%

Monthly Energy (MWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	
2014	59,620	52,503	52,082	46,948	53,022	56,113	57,542	59,826	52,069	48,518	49,546	51,507	639,296	
2015	56,447	53,102	51,457	46,211	50,153	55,823	59,570	56,652	53,195	47,716	46,348	48,409	625,083	
2016	54,102		49,321	51,618	46,443	51,425	55,807	58,401	58,055	52,489	47,976	47,793	49,799	623,229
	2017	57,487	52,324	51,294	46,151	51,101	55,456	58,033	57,690	52,158	47,674	47,492	49,485	626,345
	2018	57,774	52,586	51,550	46,381	51,357	55,733	58,323	57,979	52,419	47,912	47,729	49,733	629,477
	2019	58,063	52,849	51,808	46,613	51,613	56,012	58,615	58,269	52,681	48,152	47,968	49,981	632,624
2020	58,353	53,113	52,067	46,846	51,871	56,292	58,908	58,560	52,945	48,392	48,208	50,231	635,787	
2021	58,937	53,644	52,588	47,315	52,390	56,855	59,497	59,146	53,474	48,876	48,690	50,733	642,145	
2022	59,526	54,181	53,114	47,788	52,914	57,423	60,092	59,737	54,009	49,365	49,177	51,241	648,567	
2023	60,121	54,722	53,645	48,266	53,443	57,998	60,693	60,334	54,549	49,859	49,669	51,753	655,052	
2024	60,723	55,270	54,181	48,748	53,978	58,578	61,300	60,938	55,094	50,357	50,165	52,271	661,603	
2025	61,330	55,822	54,723	49,236	54,517	59,163	61,913	61,547	55,645	50,861	50,667	52,793	668,219	
2026	61,943	56,381	55,270	49,728	55,063	59,755	62,532	62,163	56,202	51,370	51,174	53,321	674,901	

Monthly Peaks (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer	Winter
2014	102	96	89	77	97	106	105	108	104	93	90	84	108	102
2015	100	97	88	76	90	104	109	106	104	87	76	82	109	100
2016	94	91	83	76	90	104	109	106	104	87	71	77	109	94
2017	99	96	87	76	90	104	109	106	104	87	75	81	109	99
2018	100	97	88	77	91	105	110	107	105	88	76	82	110	100
2019	100	97	88	77	91	105	111	107	105	88	76	82	111	100
2020	101	98	89	77	92	106	111	108	106	89	76	83	111	101
2021	102	99	89	78	93	107	112	109	107	90	77	83	112	102
2022	103	100	90	79	94	108	113	110	108	90	78	84	113	103
2023	104	101	91	80	94	109	114	111	109	91	79	85	114	104
2024	105	102	92	81	95	110	116	112	110	92	80	86	116	105
2025	106	103	93	81	96	111	117	114	111	93	80	87	117	106
2026	107	104	94	82	97	112	118	115	112	94	81	88	118	107

[redacted]

From: Eacret, Mark
Sent: Monday, February 12, 2018 7:53 AM
To: Brad Bickett
Cc: Parsley, Marlene
Subject: SEPA Capacity

Brad,

Marlene has been following a MISO effort to establish External Load Zones for capacity resources. She can provide much more detail, but the essence is that our SEPA resources, which are external to MISO, could receive a different price in the MISO Planning Resource Auction than that charged to our load. The external resource price would probably be lower than the load price. It affects all MISO members with a SEPA allocation, including our 178 MW allocation and HMPL's 12 MW allocation.

(Note that when installed capacity is converted to MISO ZRC's, there is an adjustment for outages. BREC receives 154 ZRC's for its SEPA allocation and HMPL receives 10 ZRC's. ZRC's are the unit of measure for determining resource adequacy.)

MISO has not made a decision at this point and it would <u>not</u> apply to Planning Year 2018 (starting 6/1/2018), but I wanted to make you aware of the issue. Marlene would be happy to catch you up on the details if you would like.

Mark J. Eacret
Vice President Energy Services
Big Rivers Electric Corporation
[redacted]

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Case No. 2019-00269
Attachment 4 for Response to HMPL 2-43
Witness: Mark J. Eacret

[redacted]

From: Eacret, Mark
Sent: Wednesday, March 21, 2018 3:43 PM
To: 'Brad Bickett'
Subject: Book2.xlsx
Attachments: Book2.xlsx

Brad,

Attached is a spreadsheet with two tabs:

The first calculates the ZRC's required for HMPL load based on our understanding of your peak and coincidence factor

The first is an example of the Make Whole Payment issue that I mentioned today. All of the numbers are for illustration only, but it points out the issue of how one would allocate the MWP over potentially three different buckets.

Mark

Big Rivers Electric Corp
Calculation of HMPL Resource Adequacy Requirement
2018/2019 Planning Year

Projected HMPL NCP		107.3	
MISO Coincidence Factor		97%	
Coincident Peak		104.0	
Losses	0.017	1.8	
Planning Reserves	0.084	8.7	
HMPL ZRC Requirement		114.5	
SEPA ZRC Allocation		(10.0)	
ZRC Balance Required		104.5	
ZRC/MW Capacity		0.838	
		124.7	2018/2019 Reservation Capacity Requirement

	Capacity	ZRC	
Unit 1	153.0	136.2	
Unit 2	157.6	124.2	
	310.6	260.4	
		83.8%	One MW of Capacity equals .838 ZRC's.

Big Rivers Electric Corp
Example of MWP

Assumed Cost	$	31.00
Start Cost	$	50,000

	DA LMP	HMPL Load	Generation	Excess	BREC	Revenue
1	$ 35.98	73	157	42	42	$ 5,649
2	35.52	72	157	43	42	5,576
3	33.77	71	157	44	42	5,302
4	36.22	71	157	44	42	5,686
5	36.19	73	157	42	42	5,682
6	38.75	75	157	40	42	6,084
7	47.77	80	157	35	42	7,500
8	62.65	84	157	31	42	9,836
9	55.71	83	157	33	42	8,746
10	49.21	79	157	36	42	7,726
11	44.21	75	157	40	42	6,941
12	39.90	71	115	44	-	4,589
13	36.79	68	115	47	-	4,231
14	34.01	65	115	50	-	3,911
15	33.71	64	115	51	-	3,877
16	32.49	63	115	52	-	3,737
17	32.10	64	115	51	-	3,692
18	38.78	67	115	48	-	4,460
19	43.67	72	157	43	42	6,856
20	41.10	73	140	42	25	5,755
21	38.12	73	123	42	8	4,689
22	39.17	72	107	35	-	4,191
23	35.38	70	90	20	-	3,184
24	33.24	66	73	7	-	2,426
	$ 39.77	1,725	3,222	960	537	$ 130,324

Start Cost		$ 50,000
Variable Cost		99,882
	Total	$ 149,882
Revenue		$ 130,324
Make Whole Payment		$ 19,558
Make Whole Payment per MWh Generated		$ 6.07
Make Whole Payment per MWh of Excess		$ 20.37

[redacted]

From: Eacret, Mark
Sent: Monday, May 14, 2018 10:52 AM
To: Brad Bickett
Cc: Pullen, Mike
Subject: FW: Book2.xlsx
Attachments: Book2.xlsx

Brad,

These are the numbers that we have. Mike and I discussed the requirement with Ken on 5/3. Neither Ken nor Mike and I had the numbers in front of us at the time, but estimated in the call that the requirement was 123 MW or so. He said that he would discuss it with Chris. The 115 MW in the capacity reservation letter leaves HMPL 8 ZRC's short. HMPL needs to increase its reservation 10 MW to add that number of ZRC's. I'm paraphrasing, but under our contracts, HMPL needs to reserve enough capacity to serve it native load.

Mark

From: Eacret, Mark
Sent: Wednesday, March 21, 2018 3:43 PM
To: 'Brad Bickett'
Subject: Book2.xlsx

Brad,

Attached is a spreadsheet with two tabs:

The first calculates the ZRC's required for HMPL load based on our understanding of your peak and coincidence factor

The first is an example of the Make Whole Payment issue that I mentioned today. All of the numbers are for illustration only, but it points out the issue of how one would allocate the MWP over potentially three different buckets.

Mark

[redacted]

From: Eacret, Mark
Sent: Wednesday, May 16, 2018 9:30 AM
To: Berry, Bob
Cc: Pullen, Mike; Chambliss, Laura
Subject: HMPL Capacity Reservation

Bob,

I followed up with Brad this morning on the HMPL capacity reservation for the next year. He said that he had discussed it with Chris and Ken, but that there was no decision yet.

We had provided him with our calculations to support a reservation requirement of 124.7 MW. Brad said that our numbers seemed reasonable. I asked if he could provide me with their support for the 115 MW. He said that they had arrived at the 115 "using the old method". I asked that HMPL provide the support for their capacity reservation when they get back with us.

Mark J. Eacret
Vice President Energy Services
Big Rivers Electric Corporation
[redacted]

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Case No. 2019-00269
Attachment 7 of Resposne to HMPL 2-43
Witness: Mark J. Eacret

[redacted]

From: Eacret, Mark
Sent: Wednesday, May 16, 2018 2:04 PM
To: Berry, Bob
Cc: Pullen, Mike; Chambliss, Laura
Subject: HMPL Capacity Reservation

I had asked Brad Bickett for information on how HMPL calculated 115 MW for its capacity reservation. He provided the following information verbally:

1. They looked at their peak loads and estimated how much they might be able to reduce it through energy efficiency or other programs
2. They added a 15% reserve margin
3. They used 12 MW for SEPA, even though MISO only credits the resource for 10 MW
4. They used "industry average outage rates for similar units" to adjust Station Two capability

I pointed out that none of this was consistent with MISO rules. He said that while HMPL understood why BREC joined MISO, HMPL never agreed to do so. I pointed out that Chris spoke positively of the benefits of MISO membership in the newspaper article and his presentations on the IRP, yet HMPL won't follow the rules or pay expenses. In this case, HMPL wasn't reserving enough capacity and was expecting BREC to make up the difference at our expense.

I asked him to send me something in writing to ensure that I hadn't misunderstood any of the points that he made and he said that he would do so.

Mark J. Eacret
Vice President Energy Services
Big Rivers Electric Corporation
[redacted]

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to the City of Henderson, Kentucky, and Henderson Utility Commission, d/b/a Henderson Municipal Power & Light's Supplemental Request for Information dated June 18, 2020

June 29, 2020

Item 44) ***State when and describe how Big Rivers communicated to Henderson that it intended to offer a severance package to employees terminated as a result of the closure of Station Two.***

Response) Big Rivers had a number of negotiation discussions with Henderson regarding all the costs of decommissioning Station Two, including severance, in mid-2018. Severance was mentioned in writing in the original settlement term sheet dated July 3, 2018.

Witness) Robert W. Berry