Exhibit No.:	
Issue:	Cost of Service and Rate Design
Witness:	James R. Dauphinais
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	MIEC
Case No.:	ER-2014-0258
Date Testimony Prepared:	February 6, 2015

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	**)))))**	**Case No. ER-2014-0258**

Surrebuttal Testimony and Schedule of

James R. Dauphinais

On behalf of

Missouri Industrial Energy Consumers

NON-PROPRIETARY VERSION

February 6, 2015

BRUBAKER & ASSOCIATES, INC.

Project 9913

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))))	**Case No. ER-2014-0258**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of James R. Dauphinais

James R. Dauphinais, being first duly sworn, on his oath states:

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedule which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.

3. I hereby swear and affirm that the testimony and schedule are true and correct and that they show the matters and things that they purport to show.

James R. Dauphinais

James R. Dauphinais

Subscribed and sworn to before me this 5th day of February, 2015.

Maria E. Decker

Notary Public

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2017
Commission # 13706793

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BEFORE THE PUBLIC SERVICE COMMISSION
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Surrebuttal Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME JAMES R. DAUPHINAIS WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING ON BEHALF OF MISSOURI INDUSTRIAL ENERGY CONSUMERS ("MIEC"), INCLUDING NORANDA ALUMINUM, INC. ("NORANDA")?

A Yes, I am.

Q WHAT IS THE SUBJECT OF YOUR SURREBUTTAL TESTIMONY?

A My surrebuttal testimony addresses the Rebuttal Testimony of Ameren Missouri ("Company") witness Jaime Haro regarding the inclusion of wholesale transmission expenses and revenues other than those for the transmission of purchased power in the Company's fuel adjustment clause ("FAC"). In addition, I respond to the Rebuttal Testimony of Company witness Matt Michels and Commission Staff witness Sara Kliethermes regarding the Actual Net Energy Cost ("ANEC"), and Midcontinent

Independent System Operator, Inc. ("MISO") load-based charges not included in the Company's ANEC, that the Company would avoid, if Noranda's New Madrid facility were to shut down.

The fact that I do not address a particular issue should not be interpreted as approval of any position taken by Ameren Missouri, Staff or any other party in rebuttal testimony.

Q IN YOUR DIRECT TESTIMONY, YOU EXTENSIVELY USED THE TERMS NET BASE ENERGY COST ("NBEC") AND ACTUAL NET ENERGY COST ("ANEC"). PLEASE STATE AGAIN THE MEANING OF THOSE TERMS.

A Ameren Missouri's NBEC is its base rate revenue requirement for: (i) its expenses includable in its FAC minus (ii) its revenues that are includable in its FAC. Ameren Missouri's ANEC is its actual revenue requirement for: (i) its expenses includable in its FAC minus (ii) its revenues that are includable in its FAC. Under Ameren Missouri's current FAC (and the version of its FAC that it is proposing in this proceeding), subject to a finding of prudence by the Commission, 95% of the difference between Ameren Missouri's ANEC and its authorized NBEC is recoverable from customers through Ameren Missouri's FAC between Ameren Missouri's base rate proceedings.

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY CONCLUSIONS.

A They continue to be as follows:

- All of Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel or purchased power should be removed from Ameren Missouri's FAC since Section 386.266.1, RSMo (Supp. 2011) only permits the inclusion of the cost of transportation for fuel and purchased power in an FAC – not the cost of transportation of power that is not purchased power. This will remove all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses from its FAC. This adjustment will not affect Ameren Missouri's base rate revenue requirement. However, it will increase the portion of that base rate revenue requirement included in Ameren Missouri's NBEC by approximately $7.6 million[1] based on the test year wholesale transmission revenue and expense data Ameren Missouri included in its direct case. This NBEC adjustment will need to be recalculated during the true-up phase of this proceeding due to the significant drop in MISO point-to-point transmission expenses that Ameren Missouri has seen since the December 19, 2013 integration of Entergy into MISO.[2]

- The ANEC, and MISO load-based charges not included in Ameren Missouri's ANEC, that Ameren Missouri would avoid if Noranda's New Madrid facility was shut down ranges from $28.03 to $29.39 per MWh on a normalized historical basis using the same three year averaging approach with the Polar Vortex Anomaly normalized out that Ameren Missouri, Commission Staff and MIEC used in the revenue requirement part of the case to determine off-system sales prices. The number will vary some depending on the specific method used to estimate the annual reduction.

The Company's rebuttal testimony with respect to wholesale transmission expenses and revenues relies on its absurd assertion that all of its power for its customers is purchased from MISO. If this were true, the entire output of the Company's generation facilities would be dedicated to its off-system sales and no generation fuel cost would be assigned to its customers. However, this is not the case as can be seen from Company's principal NBEC schedule, Schedule LMM-17, which clearly shows most of the Company's generation fuel cost is being assigned to customers, not off-system sales. In addition, if the Company's generation was dedicated to off-system sales, it would raise serious concerns with the inclusion of the Company's generation facilities in rate base. The Company's rebuttal testimony

[1] $36.9 million in wholesale transmission revenues and 96.5% of $30.4 million in MISO wholesale transmission expenses would be removed from Ameren Missouri's NBEC.

[2] As an alternative to excluding all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses, MIEC would be amenable to excluding all of Ameren Missouri's wholesale transmission revenues and expenses from its FAC. This alternative would exclude $36.9 million in wholesale transmission revenues and $32.3 million in wholesale transmission expenses from Ameren Missouri's NBEC, which would increase Ameren Missouri's NBEC by approximately $4.6 million rather than $7.6 million.

arguments on this issue should be given no weight as they are based on an absurd assertion.

With respect to the Company's rebuttal testimony from Mr. Michels regarding the ANEC, and MISO load-based charges not included in the ANEC, avoided if the Noranda facility shuts down, the Company's position that forecasted market prices should be used in estimating this avoided cost should be rejected because those forecasted values are not known and measurable. In addition, the Company's alternative method of using seven-years of historical data with the Polar Vortex Anomaly should be rejected because it is inconsistent with the method used by the Company, Staff and MIEC to determine the Company's NBEC value and fails to consider the ability of the Commission to review the Noranda rate over its proposed seven-year term, if warranted.

With respect to the Staff's rebuttal testimony from Ms. Kliethermes on this same issue, one of her three avoided cost estimates should be completely disregarded when evaluating the proposed Noranda rate. Specifically, her avoided cost estimate of $35.88 per MWh should be completely disregarded because it is based on only 12-months of historical data of which six months are dominated by the Polar Vortex Anomaly and its aftermath.

II. Inclusion of Wholesale Transmission Expenses and Revenues in Ameren Missouri's FAC

Q PLEASE RESTATE YOUR DIRECT TESTIMONY CONCLUSION WITH RESPECT TO THE INCLUSION OF WHOLESALE TRANSMISSION EXPENSES AND REVENUES IN THE COMPANY'S FAC.

A I concluded:

> "All of Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel or purchased power should be removed from Ameren Missouri's FAC since Section 386.266.1, RSMo (Supp. 2011) only permits the inclusion of the cost of transportation for fuel and purchased power in an FAC – not the cost of transportation of power that is not purchased power. This will remove all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses from its FAC. This adjustment will not affect Ameren Missouri's base rate revenue requirement. However, it will increase the portion of that base rate revenue requirement included in Ameren Missouri's Net Base Energy Cost ("NBEC") by approximately $7.6 million[3] based on the test year wholesale transmission revenue and expense data Ameren Missouri included in its direct case. This NBEC adjustment will need to be recalculated during the true-up phase of this proceeding due to the significant drop in MISO point-to-point transmission expenses that Ameren Missouri has seen since the December 19, 2013 integration of Entergy into MISO."[4] (Dauphinais Direct at 2)

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF MR. HARO ON BEHALF OF THE COMPANY IN RESPONSE TO YOUR DIRECT TESTIMONY ON THIS ISSUE?

A Yes.

Q DOES THE COMPANY AGREE WITH YOUR DIRECT TESTIMONY CONCLUSION WITH RESPECT TO THIS ISSUE?

A No. With respect to wholesale transmission expenses incurred to transmit off-system sales, the Company:

- Indicates I have previously testified these costs should be included in the FAC;

[3]$36.9 million in wholesale transmission revenues and 96.5% of $30.4 million in MISO wholesale transmission expenses would be removed from Ameren Missouri's NBEC.

[4]As an alternative to excluding all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses, MIEC would be amenable to excluding all of Ameren Missouri's wholesale transmission revenues and expenses from its FAC. This alternative would exclude $36.9 million in wholesale transmission revenues and $32.3 million in wholesale transmission expenses from Ameren Missouri's NBEC, which would increase Ameren Missouri's NBEC by approximately $4.6 million rather than $7.6 million.

- Indicates these costs have been included in the Company's FAC since the inception of the FAC; and

- Argues my recommendation would create a mismatch in the FAC by including off-system sales revenues in the FAC while excluding the transmission cost incurred to produce those off-system sales revenues from the FAC.

(Haro Rebuttal at 14-17)

With respect to wholesale transmission expenses incurred for the transmission of purchased power, the Company essentially argues Ameren Missouri purchases all of its power needs for its customers from MISO and sells the entire output of its generation facilities as off-system sales (*Id.* at 17-29).

With respect to wholesale transmission revenues, the Company indicates the Company agreed to include them in its FAC in its last base rate proceeding and continues to think it makes sense for them to be included in the Company's FAC (*Id.* at 29-30).

Q HOW DO YOU RESPOND TO THE COMPANY'S ARGUMENTS WITH RESPECT TO WHOLESALE TRANSMISSION EXPENSES INCURRED TO TRANSMIT OFF-SYSTEM SALES?

A When my testimony in Case No. ER-2012-0166 was given, I did not review Section 386.266 and whether recovery of wholesale transmission expenses incurred to transmit off-system sales through an FAC was permissible under Missouri law. In this case, however, the MIEC has focused on Section 386.266.1, RSMo., and believes, as do I, that only wholesale transmission expenses incurred for the transportation of purchased power are recoverable under the FAC. I am not a lawyer, and therefore did not analyze this legal issue in connection with my testimony in Case No. ER-2012-0166.

From a policy perspective, I continue to stand by my Case No. ER-2012-0166 testimony with respect to the inclusion of wholesale transmission expenses incurred to transmit off-system sales to the extent it is ultimately determined legal to recover these expenses in the FAC. These are short-term incremental costs that are incurred to enable off-system sales margins to be earned in order to lower the Company's ANEC and, thus, its fuel adjustment factor. However, if Section 386.266.1, RSMo (Supp. 2011) does not allow the inclusion in the FAC of wholesale transmission expenses incurred to transmit off-system sales, they cannot be included in the FAC.

Q IF THESE EXPENSES ARE EXCLUDED FROM THE FAC AS YOU HAVE RECOMMENDED IN YOUR DIRECT TESTIMONY IN THIS PROCEEDING, WOULD IT CREATE A SIGNIFICANT MISMATCH IN THE FAC AS SUGGESTED BY THE COMPANY SINCE OFF-SYSTEM SALES REVENUES WOULD STILL BE INCLUDED IN THE FAC?

A No. The vast majority of Ameren Missouri's off-system sales are to MISO and, as such, do not have any wholesale transmission expenses associated with them. In addition, the wholesale transmission expenses associated with those off-system sales made by the Company outside of MISO are dwarfed by the fuel costs incurred to make those off-system sales. Consequently, excluding the wholesale transmission expenses incurred to transmit off-system sales from the FAC will have very little impact and thus will not create a mismatch of any significance in the FAC.

Q HOW DO YOU RESPOND TO THE COMPANY'S CLAIM IN MR. HARO'S REBUTTAL TESTIMONY THAT IT PURCHASES ALL OF ITS POWER FOR ITS CUSTOMERS FROM MISO?

A The claim is absurd. The absurdity becomes clear when the implications of the claim are considered.

Q WHAT ARE THE IMPLICATIONS OF THE CLAIM IF IT WERE TRUE?

A If we ignore the fact the Company generates almost all the power it sells to its customers, and instead engage in the fiction that it sells all of its generated power to MISO as off-system sales and buys it back for its customers as purchased power:

- The fuel and purchased power cost for power paid by customers would be equal to the wholesale market price for power -- not the Company's cost to produce power in its own generating units supplemented by occasional wholesale market purchases; and
- The entire output of the Company's generation facilities would be dedicated to the production of off-system sales -- not to serving the Company's customers.

Under this scenario, the Company's accounting with the Commission would not assign any generation fuel costs to customers -- only purchased power costs would be assigned to customers. In addition, there would be grounds for the Commission to remove from the Company's rate base the entire net plant of the Company's generation facilities since those facilities would no longer be serving the Company's customers.[5]

[5]Obviously, if this was done, the fuel expenses, O&M expenses and off-system sales revenues associated with the Company's generation facilities would also be removed from rates.

Q WHAT DO THE COMPANY'S OWN ACCOUNTING SCHEDULES IN THIS PROCEEDING SHOW?

A The Company's own accounting schedules show that most of the fuel cost it incurs is incurred to serve its load -- not its off-system sales. Specifically, referring to Ameren Missouri witness Laura Moore's Schedule LMM-17, in the calculation of its NBEC in its direct testimony, the Company indicated that $682,452,000 would be incurred for fuel consumed in its own generation facilities to serve its load (i.e., its customers) and only $171,791,000 would be incurred for fuel consumed in its own generation for off-system sales (Schedule LMM-17 at lines 1 and 7). Clearly, if the Company was purchasing all of its power for its load and selling all of the power it generates as off-system sales, it would show $0 of generation fuel cost to serve its load and $854,243,000 of generation fuel cost for off-system sales. The Company is clearly not claiming this on its own schedules in this proceeding.

Q HAS THE COMPANY EVER PREVIOUSLY ADMITTED THAT IT DOES NOT PURCHASE ALL OF ITS POWER FOR ITS CUSTOMERS FROM MISO?

A Yes. In its September 7, 2006 comments to the Commission in Docket No. EX-2006-0472 regarding fuel and purchased power cost recovery mechanisms such as FACs, the Company stated:

> "FACs allow utilities to timely pass through the necessary costs (subject to full prudence review and other consumer protections discussed below) associated with obtaining the fuel needed to fire the generation that serves customers, as well as the costs associated <u>with purchased power needed to supplement the energy and capacity available from the utility-owned generation</u>."
>
> (Docket No. EX-2006-0472, Comments of Union Electric Company d/b/a AmerenUE, September 7, 2006 at page 2, emphasis added)

This statement, which was made well after the Company's integration in MISO and the April 1, 2005 startup of the MISO Day 2 energy markets, clearly shows that the Company has previously recognized it serves its load from its own generating units and supplements this generation with power purchases. The Company's participation in the MISO market on behalf of its customers does not artificially convert the Company's generated power for its customers into purchased power.

Q DOES THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") SPECIFY HOW GENERATION AND LOAD THAT IS CLEARED ON AN HOURLY BASIS IN RTO MARKETS SUCH AS THAT OF MISO SHOULD BE CLASSIFIED?

A Yes. In Order No. 668, FERC specified how the hourly clearing in RTO markets of load and generation should be addressed under the uniform system of accounts by public utilities such as the Company. Under Order No. 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) a sale for resale (i.e., off-system sale) under Account 447 when the utility's cleared generation exceeds the cleared load or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. Thus, under FERC's accounting rules, in each hour, a public utility has either an off-system sale to MISO or a power purchase from MISO -- not both. As FERC indicated in Order No. 668:

> "Netting accurately reflects what participants would be recording on their books and records in absence of the use of an RTO market to serve their native load." (FERC Order No. 668 at paragraph 80)

Q MR. HARO ARGUES THAT THE TOTAL PURCHASED POWER AMOUNT YOU CITED FROM A WORKPAPER OF COMPANY WITNESS MARK PETERS IS A NET AMOUNT (HARO REBUTTAL AT 21-22). HOW DO YOU RESPOND?

A The amount in question is the total of the Company's purchased power. The only netting that takes place is what takes place in each hour. As I have noted, in each hour, the Company's cleared load and cleared generation is netted as either an off-system sale to MISO or a power purchase from MISO. This does not make the purchased power total I cited from Mr. Peters' workpaper a net amount. Furthermore, as I have also noted, if the Company purchased all of its power needs for its customers from MISO, it could not assign any of its generation fuel cost to its load in Ms. Moore's Schedule LMM-17 -- all of the Company's fuel cost for generation would have to be assigned to its off-system sales.

Q MR. HARO INDICATES THAT THE COMPANY BIDS ITS LOAD AND OFFERS ITS GENERATION INTO THE MISO MARKET ON A GROSS BASIS AND ITS MISO SETTLEMENT STATEMENTS CLEAR THESE ITEMS ON A GROSS BASIS (HARO REBUTTAL AT 23-27). HOW DO YOU RESPOND?

A I have never suggested in my direct testimony that this is not the case. However, this does not change the fact that, in each hour, the Company has either an off-system sale to MISO or a power purchase from MISO -- not both.

Q MR. HARO CLAIMS THAT CERTAIN LANGUAGE IN THE MISO TARIFF THAT SUGGESTS NETWORK INTEGRATION TRANSMISSION SERVICE PROVIDES FOR DELIVERY OF POWER FROM A TRANSMISSION CUSTOMER'S GENERATION TO ITS LOAD IS SIMPLY LANGUAGE THAT MISO HAS FAILED TO UPDATE (HARO REBUTTAL AT 27-29). HOW DO YOU RESPOND?

A The language is not outdated and not inconsistent with the balance of the MISO Tariff. It would be a stretch beyond reality to assume, as Mr. Haro has, that the word "regulate" in the preamble that Mr. Haro references has the same meaning as Schedule 3 Regulating Reserve. Furthermore, MISO market participants are allowed to dispatch their own generation facilities under the MISO Tariff and business practices. This is accomplished through the generation "must-run" and "self-schedule" provisions of the MISO Tariff. The relevant sections of the preamble cited by Mr. Haro are not outdated or out of sync with the rest of the MISO Tariff.

Q HOW DO YOU RESPOND TO MR. HARO'S POSITION WITH RESPECT TO INCLUSION OF WHOLESALE TRANSMISSION REVENUES IN THE COMPANY'S FAC (HARO REBUTTAL AT 29-30)?

A If the Commission ultimately concludes the wholesale transmission expenses in dispute can be legally included in the FAC, then I would agree wholesale transmission revenues should also be included in the FAC provided it is legal to do so.

III. Estimate of the ANEC and Non-ANEC Load-Based MISO Charges Avoided by Ameren Missouri if Noranda's New Madrid Facilities Shut Down

Q PLEASE RESTATE YOUR DIRECT TESTIMONY ESTIMATE OF THE ANEC, AND LOAD-BASED MISO CHARGES NOT INCLUDED IN THE COMPANY'S ANEC, THAT THE COMPANY WOULD AVOID IF NORANDA'S NEW MADRID FACILITIES SHUT DOWN.

A I estimated that the Company would avoid between $28.03 and $29.39 per MWh of energy sold to Noranda. This direct testimony estimate was determined on a normalized historical basis using the same three year averaging approach with the Polar Vortex Anomaly normalized out that the Company, the Commission Staff and MIEC has used in the revenue requirement part of this case to determine the off-system sales prices used in the determination of the Company's NBEC (Dauphinais Direct at 28).

A. Response of Company Witness Matt Michels

Q HAS THE COMPANY RESPONDED TO YOUR DIRECT TESTIMONY ESTIMATE?

A Yes. Company witness Matt Michels has offered rebuttal testimony in response to my estimate.

Q PLEASE SUMMARIZE HIS REBUTTAL TESTIMONY ON THIS ISSUE.

A As in Case No. EC-2014-0224, the Company continues to advocate calculating the avoided cost on the basis of forecasted prices over the proposed term of the Noranda rate (seven years in this proceeding). Notwithstanding, the Company believes a historical-based estimate, if used, should be calculated on the basis of a historical average of data of the same length as the proposed term of the Noranda rate (again, seven years) with Polar Vortex Anomaly included rather than using three years of historical data with the Polar Vortex Anomaly normalized out. In addition, the Company opposes the market price reduction for the loss of Noranda load that I included in the low end of my avoided cost estimate (Michels Rebuttal at 22-26).

Q DID THE COMPANY PROVIDE ITS OWN HISTORICAL-BASED AVOIDED COST ESTIMATE IN MR. MICHELS' REBUTTAL TESTIMONY?

A Yes. Using seven years of historical data with the Polar Vortex Anomaly included, the Company estimated the ANEC, and load-based MISO charges not included in the Company's ANEC, that the Company would avoid if the Noranda facility shut down ranges from $32.77 to $34.13 per MWh of energy sold to Noranda. The lower end of this range includes my Auction Revenue Right ("ARR") adjustment and my market price reduction for the loss of Noranda load. The upper end of the Company's range excludes these two adjustments (Michels Rebuttal at 26).

Q HOW DO YOU RESPOND TO THE COMPANY'S POSITION THAT, WHEN THE AVOIDED COST PRICE IS CALCULATED ON A HISTORICAL BASIS, IT SHOULD BE CALCULATED USING SEVEN YEARS OF HISTORICAL DATA WITH THE POLAR VORTEX ANOMALY INCLUDED?

A I disagree with the Company. First, while Noranda has proposed a seven-year term, Noranda has also recognized that the Commission can review the rate in future base rate proceedings. As such, the proposed rate could be modified by the Commission during that seven-year term. As a result, there is no need to sync up the length of the averaging period for historical data with the length of the term of the Noranda rate.

Second, the Company's attempt in Mr. Haro's testimony to differentiate the setting of a rate for Noranda from the setting of the Company's NBEC in its base rates falls flat. Specifically, Mr. Haro indicates normalizing out anomalies may be appropriate for setting a short-term baseline, such as the NBEC, for which ongoing true-ups are made through mechanisms such as the FAC, but it is not for a rate such as that proposed by Noranda (Michels Rebuttal at 25). However, the Company's memory is apparently short for, as I detailed in my surrebuttal testimony in Case No. EC-2014-0024, in Case No. ER-2007-0002, the Company proposed to normalize out certain market anomalies from a three year average of historical prices for its NBEC even if the Commission chose not to grant the FAC it requested in that proceeding (Case No. EC-2014-0224 Dauphinais Surrebuttal at 10-12).

Q THE UPPER END OF THE COMPANY'S SEVEN YEAR HISTORICAL AVERAGE AVOIDED COST ESTIMATE EXCLUDED YOUR ARR ADJUSTMENT AND YOUR MARKET PRICE REDUCTION FOR THE LOSS OF NORANDA LOAD. HAS THE COMPANY OFFERED ANY TESTIMONY IN THIS PROCEEDING IN OPPOSITION TO YOUR ARR ADJUSTMENT?

A No. In fact, the Company's avoided cost estimate based on its forecasted market prices, which I will discuss later in my testimony, included my ARR adjustment. Inclusion of my ARR adjustment in the upper end of the Company's seven-year historical average avoided cost estimate would lower the upper end of the Company's seven year historical avoided cost estimate by **______** per MWh to **______** per MWh.

Q PLEASE SUMMARIZE MR. MICHELS' CRITICISMS REGARDING YOUR METHOD FOR DETERMINING THE IMPACT ON WHOLESALE MARKET PRICES OF A LOSS OF NORANDA'S LOAD.

A Mr. Michels makes two major arguments with respect to my analysis. First, he contends that my analysis is flawed because I have implicitly assumed that hourly changes in load and price, regardless of the location where the change in load occurred, are reflective of the impact of a reduction of load across all hours at a specific location (Michels Rebuttal at 25-26). He then extends this argument suggesting further that my regression analysis ignores the fact that the hourly fluctuations in MISO's load would exist with or without Noranda and also that the hourly fluctuations in price are primarily a function of these hourly changes in load, including the location of such changes, which would exist whether or not the smelter remains on the system (*Id.*).

Mr. Michels' second argument was to offer a suggested analysis that in his opinion would be a more appropriate way to determine the impact on wholesale market prices due to a specific reduction in load (*Id.*).

Q HOW DO YOU RESPOND TO MR. MICHELS' CONCERNS?

A Mr. Michels is correct that my analysis was not location specific with regard to the load reduction. My analysis examined total hourly MISO load and wholesale AMMO.UE[6] LMP price changes in MISO during the period from 2011 – 2013. Consequently, I have considered all hourly fluctuations in MISO load inclusive and exclusive of Noranda. Furthermore, the intent of my analysis was to empirically estimate the impact on the wholesale price of electricity at the AMMO.UE CP Node

[6]AMMO.UE is the MISO pricing node where the Company clears its load in the MISO market.

due to a change of load within MISO. MISO uses Locational Marginal Pricing ("LMP") to determine the location specific wholesale price of electricity. However, LMP is actually an aggregation of three smaller pricing components: the Marginal Energy Component ("MEC"), the Marginal Loss Component ("MLC"), and the Marginal Congestion Component ("MCC"). The LMP is equal to the sum of the MEC, MLC and MCC.

The MEC is the largest component of the AMMO.UE LMP and is not location specific. In fact, in a system of infinite transmission capacity and no losses, the LMP would be the same at every point on the system and the LMP would be equal to the MEC. My analysis is based on the reasonable determination that to exclude changes in the MLC and MCC components of the LMP is a conservative approach. That is to say, excluding them, if anything, understates the market price reduction that would result from the loss of Noranda's load.

Q IF YOUR ANALYSIS IS BASED ON ONLY CONSIDERING THE MEC COMPONENT OF THE LMP, WHY DID YOU PERFORM IT TO ESTIMATE THE PERCENTAGE CHANGE OF THE LMP TO A UNIT LOSS OF LOAD INSTEAD OF A PERCENTAGE CHANGE OF THE MEC TO A UNIT LOSS OF LOAD?

A I did so to be conservative. My analysis was actually performed both for a percentage change of LMP and a percentage change of MEC. The percentage change of LMP approach yielded a lower value. I chose to use it to be conservative.

Q YOU HAVE INDICATED THAT UNLIKE THE MEC VALUE, THE MLC AND MCC VALUES ARE LOCATION SPECIFIC. IN ADDITION, YOU HAVE INDICATED IT WAS CONSERVATIVE TO EXCLUDE THESE TWO LOCATION SPECIFIC COMPONENTS FROM YOUR ANALYSIS. PLEASE EXPLAIN WHY IT WAS CONSERVATIVE FOR YOU TO DO SO.

A It was conservative to do so because a reduction of load at the AMMO.UE Node can only decrease the MCC and MLC values at the AMMO.UE Node and Ameren Missouri's generation nodes -- not increase them. Specifically, a reduction of load at Noranda's facility is a reduction of market demand at the AMMO.UE Node, which can only lower the MCC and MLC values by at least a very small amount at that node.

Furthermore, if during a given hour there is no transmission congestion between the AMMO.UE Node and the Ameren Missouri generation nodes, the same MCC and MLC reductions at the AMMO.UE Node would also be seen at the Ameren Missouri generation nodes. If there is transmission congestion between the AMMO.UE Node and Ameren Missouri's generation nodes, the AMMO.UE Node MCC and MLC reductions will be seen to a lesser degree or not at all at the Ameren Missouri generation nodes. However, under no circumstances would the loss of Noranda load cause the MCC and MLC values at the Ameren Missouri generation nodes to increase because a loss of Noranda load can neither increase demand nor decrease supply in the wholesale energy market at those locations. Thus, the overall effect of excluding MCC and MLC values from my analysis was to conservatively understate the percentage change in LMP that would result from a loss of Noranda load.

Q DO YOU AGREE THAT AN ANALYSIS USING A SIMULATION TOOL THAT MODELS LOCAL TRANSMISSION AND CONGESTION (SUCH AS VENYX'S PROMOD) IS A MORE APPROPRIATE WAY TO DETERMINE THE IMPACT ON WHOLESALE MARKET PRICES OF A SPECIFIED REDUCTION IN LOAD?

A I do not dispute the analysis suggested by Mr. Michels would produce an estimate of the impact on wholesale prices due to a specified load reduction and such an analysis would capture the location specific congestion effects that my analysis did not consider. However, this type of analysis would also be based on numerous simplifying assumptions in the market model as well as simulated and forecasted data, where as my analysis relies on actual MISO operating data.

Mr. Michels chose not to perform the analysis he proposes even though the Company currently licenses a number of products from Ventyx. Without actually performing the analysis, one could speculate on what the results might be. However, my analysis has quantified the expected percent change in wholesale prices due to a change in MISO load using actual (not simulated) data. Furthermore, as Mr. Michels admits, "hourly fluctuations in price are primarily a function of [these] hourly changes in load, including the location of such changes…" which is the very premise on which my analysis is based. That is, that we can estimate the change in wholesale prices by statistically analyzing historic changes in price versus the corresponding historic changes in load. Furthermore, as I have discussed, excluding the location specific effects from such an analysis only acts to conservatively understate the wholesale market price reduction that would result. My wholesale market price reduction estimate for the loss of Noranda load adjustment was reasonably determined and should be incorporated into all of the avoided cost estimates.

Q DO YOU CONTINUE TO RECOMMEND THE COMMISSION USE YOUR $28.03 PER MWH THREE YEAR HISTORICAL AVERAGE OF MARKET PRICES WITH THE POLAR VORTEX ANOMALY NORMALIZED OUT AVOIDED COST ESTIMATE?

A Yes. For the reasons I have discussed above, it remains the most reasonable avoided cost estimate.

Q IF DESPITE YOUR RECOMMENDATION, THE COMMISSION CHOOSES TO UTILIZE A SEVEN-YEAR HISTORICAL AVERAGE OF MARKET PRICES WITH THE POLAR VORTEX ANOMALY INCLUDED FOR THE AVOIDED COST ESTIMATE, HOW SHOULD IT BE UTILIZED?

A It should be utilized with my ARR adjustment and market price adjustment for the loss of Noranda included, essentially the Company's $32.77 per MWh value. In addition, the $32.77 per MWh value should not be compared to the first year value of the proposed Noranda rate of $32.50 per MWh. To be fair, it should be instead compared to the seven-year average of the proposed Noranda rate of $33.49 per MWh.

Q DID THE COMPANY ALSO PROVIDE AN AVOIDED COST ESTIMATE BASED ON ITS FORECAST OF WHOLESALE MARKET PRICES OVER THE PROPOSED SEVEN YEAR TERM OF THE NORANDA RATE?

A It did so indirectly in Mr. Michels' rebuttal testimony by providing an estimate of $272 million as the difference between Noranda revenues under the Noranda proposal and the avoided cost to serve Noranda based on forecasted prices; and more directly in Mr. Michels' rebuttal testimony workpapers.

Specifically, in Mr. Michels' rebuttal testimony workpapers, the Company provided an avoided cost estimate of **_______** per MWh of energy sold to Noranda based on its forecast of future wholesale market prices. This estimate includes my ARR adjustment but not my market price reduction for the loss of Noranda load (Michels Rebuttal at 28-29 and Workpaper UE_REB-UE_REB_021_Michels-Att-MRM Workpaper Noranda Price Comparison.xlsx).

Q IS IT APPROPRIATE TO USE FORECASTED MARKET PRICES TO ESTABLISH A RATE FOR NORANDA IN THIS PROCEEDING?

A No. As I discussed at length in my surrebuttal testimony in Case No. EC-2014-0224, neither forward market prices for energy nor the Company's own forecasted market prices for energy and capacity are known and measurable values. As a result, they should not be utilized in setting a rate (Case No. EC-2014-0224 Dauphinais Surrebuttal at 36-37). In addition, as I also discussed at length in my Case No. EC-2014-0224 surrebuttal testimony, the Company itself has opposed the use of forward market prices to set the NBEC portion of its base rate revenue requirement, has only used 12-month forward prices when it has previously referenced forward prices in base rate proceedings and has not in any of its recent base rate proceedings utilized its own forecast of future market prices for capacity and energy (Case No. EC-2014-0224 Dauphinais Surrebuttal at 35-38).

Q PUTTING ASIDE THE REASONS FORWARD MARKET PRICES AND THE COMPANY'S OWN FORECAST OF MARKET PRICES FOR CAPACITY AND ENERGY SHOULD NOT BE USED TO ESTABLISH A RATE FOR NORANDA, DO YOU HAVE ANY CRITICISM OF THE COMPANY'S FORECASTED SEVEN YEAR AVOIDED COST ESTIMATE OF **______ PER MWH OF ENERGY SOLD TO NORANDA?**

A Yes. The capacity and energy portions of the forecast are stale. In addition, in light of the fact the Commission can review the reasonableness of the proposed Noranda rate during its seven-year term, the capacity and energy portions of the forecast are overstated. In a nutshell, certain assumptions in the Company's forecast may be reasonable for considering decisions with respect to resource planning that risk the incurrence of irrevocable costs, but they are not reasonable with respect to decisions that do not risk the incurrence of irrevocable costs such as whether Noranda's proposed rate is reasonable.

As discussed in the Surrebuttal Testimony of my colleague Nicholas L. Phillips, based on more recent forward market information for electricity and natural gas and removal of the consistent premium over spot market prices that forward market prices have historically implicitly included, the average forecasted energy market price over the seven-year period should be approximately $29.03 per MWh rather than the Company's **______** per MWh. In addition, I have reviewed the Company's forecast of market prices for capacity over the same seven-year period and recommend downward adjustments to that portion of the Company's avoided cost estimate based on seven years of forecasted prices.

Q PLEASE DESCRIBE YOUR CONCERN WITH THE COMPANY'S FORECASTED MARKET PRICE FOR CAPACITY OVER THE PROPOSED SEVEN-YEAR TERM OF THE NORANDA RATE.

A The Company's forecast of the market price for capacity assumes a rapid ramp up to the gross Cost of New Entry ("CONE") in the MISO 2019/2020 and 2020/2021 planning years. While there is a finite possibility that the market price for capacity in one or more of the Local Resource Zones ("LRZ") in MISO may rise to the value of gross CONE, Ameren Missouri presents no compelling evidence that there is a high likelihood of this occurring over the proposed seven-year term of the Noranda rate. In fact, as discussed in the Company's 2014 Integrated Resource Plan, it is simply assuming the market price will reach gross CONE in 2021 and remain there based on expectations of capacity becoming constrained in the MISO market at that time (Ameren Missouri 2014 Integrated Resource Plan at 16). However, a lot can happen in the six years between now and 2021. Therefore, it is far from given that the capacity market will be constrained in 2021, and, even it is, that it will cause MISO capacity market prices to rise to gross CONE.

Q ARE THERE OTHER REASONS TO BELIEVE THE VERY HIGH CAPACITY MARKET PRICES THAT THE COMPANY FORECASTS FOR THE LAST THREE YEARS OF SEVEN YEAR TERM OF THE NORANDA RATE ARE NOT LIKELY TO MATERIALIZE AS CLAIMED BY THE COMPANY?

A Yes. First, unlike in the ISO New England, New York ISO and PJM capacity markets, the vast majority of the load in the MISO market is served by vertically integrated utilities under regulated retail rates. As a result, there is only a very limited reliance on the capacity market in MISO and that market is residual in nature. This makes it less likely than in the other Regional Transmission Organization (“RTO”) markets for the actual annual capacity market in MISO to become tight enough to produce auction clearing prices for capacity at gross CONE levels. Second, the most recent Loss of Load Expectation (“LOLE”) study completed by MISO identified significant transmission limitations for exports of capacity from MISO LRZ 5 that may seriously restrict Ameren Missouri’s ability to make off-system capacity sales in the MISO annual Planning Resource Auction (“PRA”).[7] This may significantly depress the market price for capacity in LRZ 5, where Ameren Missouri is located, versus the remainder of northern and central MISO, where market prices for capacity may be much higher.

Q HOW WOULD YOU PROPOSE TO MODIFY THE COMPANY’S CAPACITY MARKET PRICE FORECAST?

A I propose to eliminate the rise to gross CONE in the Company’s forecast and instead apply the percent change from 3rd year to the 4th year in the forecast (**__**%) as the annual capacity market price escalation for the 5th through 7th years of the forecast. This yields a more reasonable average forecasted capacity market price of **_____** per kW-month over the seven-year period than the Company’s **______** per kW-month average over the same period.

[7] MISO Planning Year 2015-2016 Loss of Load Expectation Study Report, November 1, 2014 at pages 5, 16 and 20. A copy of this report is provided in my Schedule JRD-12.

Q IF YOU COMBINE THE FORECASTED ENERGY MARKET PRICE REDUCTIONS PROPOSED BY MR. PHILLIPS WITH YOUR FORECASTED CAPACITY MARKET PRICE REDUCTIONS, WHAT DOES IT DO TO THE COMPANY'S SEVEN-YEAR FORECASTED MARKET PRICE AVOIDED COST ESTIMATE OF **______ PER MWH?**

A It lowers the estimate significantly. Specifically, the Company's seven-year forecasted market price avoided cost estimate would be lowered to $34.89 per MWh. This estimate does not include the impact of the market price reduction for the loss of Noranda load that would occur. Assuming the impact of the market price reduction is of the same magnitude as it is in the historical market price-based avoided cost estimates, it would lower the $34.89 per MWh another $1.05 per MWh to $33.84 per MWh. This is $0.35 per MWh higher than the seven-year average of Noranda's proposed rate of $33.49 per MWh. However, the $33.84 per MWh avoided cost estimate is just a forecast. The actual avoided cost may be either lower or higher depending on the spot energy market prices and annual capacity market prices that actually occur in the future. In addition, as Noranda has recognized in its testimony in this proceeding, the Commission can revisit the proposed Noranda rate in future base rate cases if warranted.

B. Response to Staff Witness Sarah Kliethermes

Q HAS THE COMMISSION STAFF RESPONDED TO YOUR DIRECT TESTIMONY ESTIMATE?

A Yes. Staff witness Sarah Kliethermes has offered rebuttal testimony in response to my estimate. Specifically, she has offered the following three avoided cost estimates:

- $29.00 per MWh based on the Staff fuel run energy cost to serve Noranda, with transmission and other costs to serve;
- $31.50 per MWh based on the average wholesale cost of Noranda energy found in Case No. EC-2014-0224, with transmission and other costs to serve; and
- $35.88 per MWh based on 12-month ending July 1, 2014 wholesale energy prices with transmission and other costs to serve.

Q ARE THESE ESTIMATES REASONABLE?

A The $29.00 per MWh estimate falls within the $28.03 per MWh to $29.39 per MWh range of my direct testimony avoided costs estimate. It is in the band of reasonableness, but, as I discussed in my direct testimony, I continue to believe my low-end estimate of $28.03 per MWh is the most accurate avoided cost estimate (Dauphinais Direct at 19).

The $31.50 per MWh estimate is the same one that Ms. Kliethermes presented in her rebuttal testimony in Case No. EC-2014-0224. It is based on a four-year average with the Polar Vortex Anomaly included. The method deviates from the NBEC historical market price normalization method supported by the Company, Staff and MIEC. As I noted in my direct testimony, because of that deviation, I continue to recommend against its use (Dauphinais Direct at 18-19)

The $35.88 per MWh estimate is completely unreasonable. It is based on only 12-months of historical data further aggravated by the inclusion of the three months of the Polar Vortex Anomaly (January, February and March of 2014) and three months in the aftermath of the Polar Vortex Anomaly that were still experiencing abnormally high market prices. For this reason, the $35.88 per MWh estimate should not be used to evaluate the reasonableness of the Noranda's proposed rate in this proceeding.

IV. Conclusions

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY CONCLUSIONS.

A They continue to be as follows:

- All of Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel or purchased power should be removed from Ameren Missouri's FAC since Section 386.266.1, RSMo (Supp. 2011) only permits the inclusion of the cost of transportation for fuel and purchased power in an FAC – not the cost of transportation of power that is not purchased power. This will remove all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses from its FAC. This adjustment will not affect Ameren Missouri's base rate revenue requirement. However, it will increase the portion of that base rate revenue requirement included in Ameren Missouri's Net Base Energy Cost ("NBEC") by approximately $7.6 million[8] based on the test year wholesale transmission revenue and expense data Ameren Missouri included in its direct case. This NBEC adjustment will need to be recalculated during the true-up phase of this proceeding due to the significant drop in MISO point-to-point transmission expenses that Ameren Missouri has seen since the December 19, 2013 integration of Entergy into MISO.[9]

- The ANEC, and MISO load-based charges not included in Ameren Missouri's ANEC, that Ameren Missouri would avoid if Noranda's New Madrid facility was shut down ranges from $28.03 to $29.39 per MWh on a normalized historical basis using the same three year averaging approach with the Polar Vortex Anomaly normalized out that Ameren Missouri, Commission Staff and MIEC used in the revenue requirement part of the case to determine off-system sales prices. The number will vary some depending on the specific method used to estimate the annual reduction.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes.

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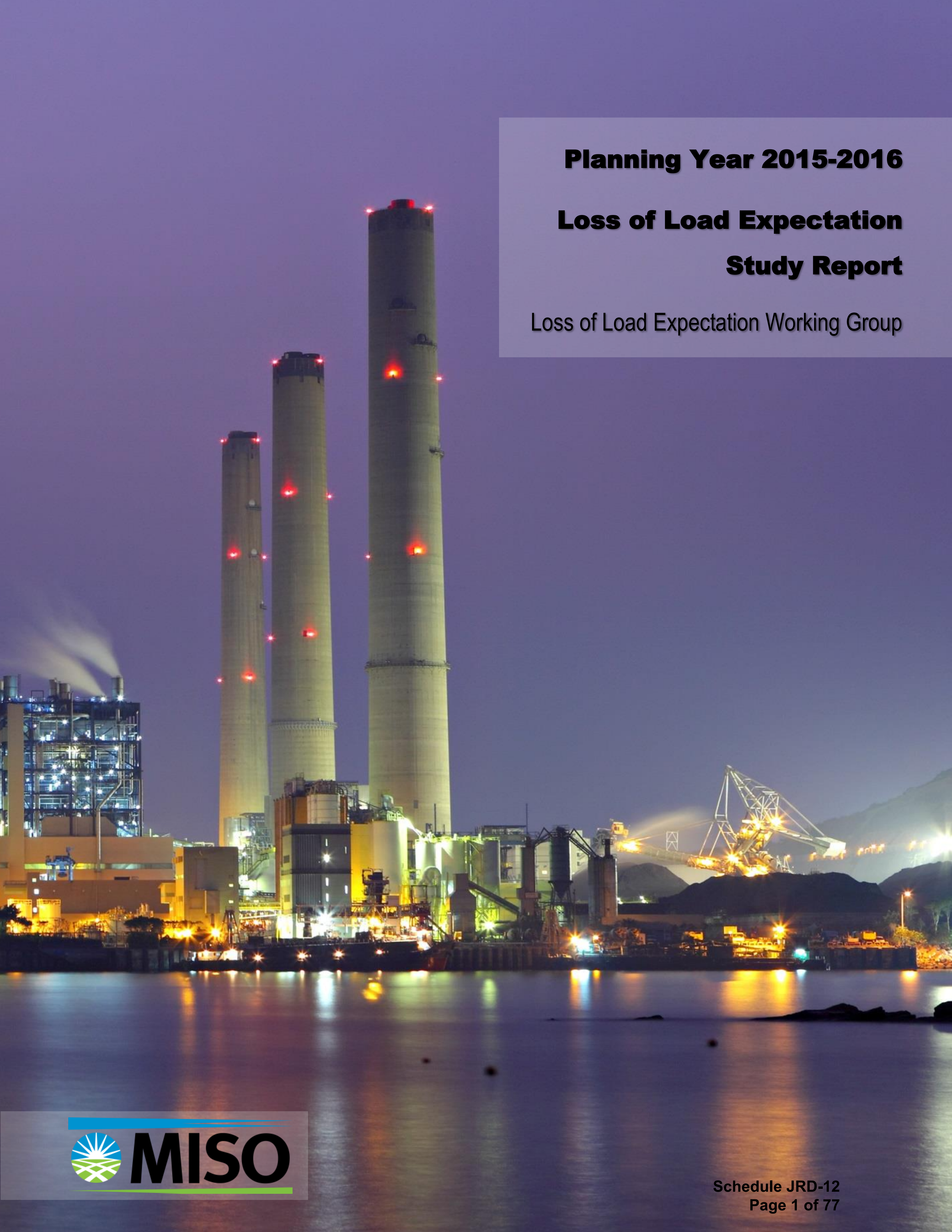
[8]$36.9 million in wholesale transmission revenues and 96.5% of $30.4 million in MISO wholesale transmission expenses would be removed from Ameren Missouri's NBEC.

[9]As an alternative to excluding all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses, MIEC would be amenable to excluding all of Ameren Missouri's wholesale transmission revenues and expenses from its FAC. This alternative would exclude $36.9 million in wholesale transmission revenues and $32.3 million in wholesale transmission expenses from Ameren Missouri's NBEC, which would increase Ameren Missouri's NBEC by approximately $4.6 million rather than $7.6 million.



Planning Year 2015-2016

Loss of Load Expectation Study Report

Loss of Load Expectation Working Group

MISO

Contents

Revision History

Reason for Revision	Revised by:	Date:
Final Posted	MISO Staff	11/1/2014

1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

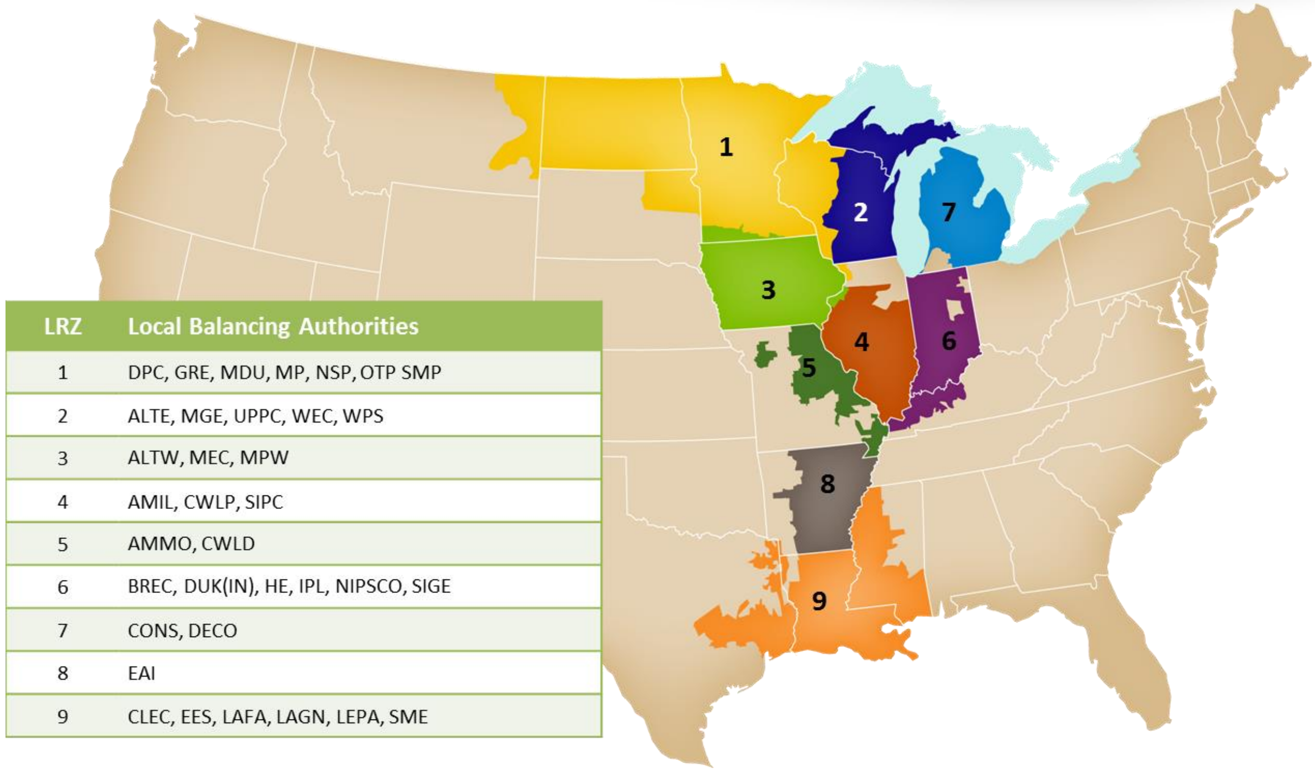
Key findings and results from the 2015-2016 Planning Year LOLE study include:

- Establishes a PRM UCAP of 7.1 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2015 and ending May 2016
- Uses the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis to provide results applicable across the MISO market footprint; any impacts due to transmission limitations will be addressed in the PRA
- Provides the PRA with the overall 7.1 percent PRM UCAP requirement, the per-unit LRR values and the initial zonal CIL and CEL for each Local Resource Zone (LRZ) (Table 1-1.1). The CILs and CELs may be adjusted within the PRA to assure that the resources cleared in the auction can be reliably delivered simultaneously.
- Determines a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.143 times that of the MISO system coincident peak.
- Sets forth zonal-based (Figure 1.1-1) PRA deliverables in the LOLE charter

RA and LOLE Metrics	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9
MISO PRM UCAP	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
LRR UCAP per unit of LRZ Peak Demand	1.111	1.151	1.137	1.214	1.211	1.108	1.142	1.270	1.112
Capacity Import Limit (CIL) (MW)	3,735	2,903	1,972	3,130	3,899	5,649	3,813	2,074	3,320
Capacity Export Limit (CEL) (MW)	604	1,516	1,477	4,125	0	2,930	4,804	3,022	3,239

Table 1.1-1: 2015 Planning Resource Auction Deliverables

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).



LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

Figure 1.1-1: Local Resource Zones (LRZ)

1.1 Study Enhancements

For the 2015-2016 planning year, several changes were made to the LOLE modeling assumptions. Modeling enhancements are necessary in order to mature and stabilize the planning reserve margin and reliability requirements.

MISO enhanced the LOLE analysis as follows:

- Modeled generation that is eligible as a Planning Resource only, consistent with MISO's PRA (Section 4.2.1)
- Modeled Behind-the-Meter Generation (BTMG) with a forced outage rate rather than as an Energy-Limited Resource (Section 4.2.2)
- Adjusted PJM's target Planning Reserve Margin based on actual cleared capacity as part of PJM's Reliability Pricing Model (RPM) (Section 4.4.2)

1.2 Acknowledgements

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group (LOLEWG) was much appreciated by the MISO staff involved in this study.

2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual Loss of Load Expectation (LOLE) study to determine the Planning Reserve Margin (PRM) on an unforced capacity (UCAP) basis for the MISO system and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand for the planning year 2015-2016.

In addition to the LOLE analysis, a transfer analysis was performed to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL and CEL are used in conjunction with the LOLE analysis results in the Planning Resource Auction (PRA). The 2015-2016 per-unit LRR UCAP values determined by the LOLE analysis will be multiplied by the updated LRZ Peak Demand forecasts submitted for the 2015-2016 Planning Resource Auction to determine each LRZ's LRR. Once the LRR is determined, the CIL values are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[2] of Module E-1. An example calculation pursuant to Section 68A.6 of the current effective Module E-1[3] shows how these values are reached (Table 2.0-1). The actual effective PRM Requirement (PRMR) will be determined when the updated LRZ Peak Demand forecasts are submitted by November 1st for the 2015-2016 PRA and the simultaneous feasibility test is complete, which ensures CIL and CEL values are not violated.

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP {1d in 10yr}	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Capacity Import Limit (CIL)	3,469	[G]
Capacity Export Limit (CEL)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Local Reliability Requirement (LRR) UCAP	16,382	[K]=[F]x[I]
Local Clearing Requirement (LCR)	12,913	[L]=[K]-[G]
Zone's System Wide PRMR	14,929	[M]=[1.071]X[J]
Planning Reserve Margin (PRM)	7.1%	[N]=[M]/[J]-1

Table 2.0-1: Example LRZ calculation

2.1 Future Study Improvement Considerations

In the past few years MISO's LOLE analysis has made many enhancements to ensure that MISO continues to send the appropriate capacity planning signals in the forward time horizon. Although MISO has confidence in the results, further improvements are still necessary to mature the process and stabilize the planning reserve margin and reliability requirements.

[2] https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#
[3] Effective Date: November 19, 2013

The 2015-2016 MISO PRM value shows a 0.2 percent decrease on a UCAP basis compared to 2014-2015. While providing the accurate PRM value to stakeholders is important, a stable PRM value in the forward time horizon is equally important for Load Serving Entities planning to meet their reliability requirement. MISO realizes the importance of both accuracy and stability of the PRM and will continue to investigate future study improvements.

When a system is more reliable than 0.1 days per year LOLE, the industry standard practice in the adjustment of capacity to meet 0.1 days per year LOLE is to add a perfect negative unit within the model. However, the MISO Tariff explicitly describes a different methodology in determination of Local Reliability Requirements. The tariff methodology effectively removes lowest UCAP units' characteristics from the generator stack in the model. A potential change to the tariff methodology aligns with the industry standard and should be discussed for future studies.

The LOLE PRM analysis utilizes a detailed generation and load model of the external system to determine the amount of support MISO can get from the external systems. The external firm support can be verified by diversity contracts and Power Purchase Agreements. The non-firm support is dictated by generation, load and the effective planning reserve margins of the external systems. MISO has no control of the data accuracy for the external systems thus the yearly external non-firm support can be volatile and error-prone. A potential improvement to stabilize the external non-firm support should be discussed for future studies.

The LOLE transfer analysis utilizes MTEP power flow models to calculate the CEL and CIL for each LRZ. Potential improvements to develop a consistent and stable power flow model or development of a methodology to smooth out volatility caused by changes other than MISO transmission should be discussed for future studies.

Section 68A.3 of Module E-1 states that "no later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new 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 Transmission Provider Region to reliably meet Demand and LOLE requirements." In order to meet this requirement, MISO is establishing an annual process to re-evaluate the boundaries of Local Resource Zones.

Currently, MISO has an annual Resource Adequacy construct. The January 2014 polar vortex brought extreme weather conditions to the MISO Region that introduced significant challenges to the reliable operation of the power grid. MISO realizes the risks brought on by the extreme weather conditions and natural gas availability during the winter peak time. Potential solutions are being investigated including a seasonal construct.

MISO is identifying process improvements to limit volatility caused by controllable variables and determine the impact of non-controllable variables. Possible improvements for the 2016 study include:

- Consider impact of long-term transmission line and generator outages
- Adjust the implementation of unit retirements or suspensions that occur after summer peak
- Align MTEP and LOLE power flow model development, review and updates
- Report additional constraints for each transfer, such as the top 3 or 5
- Identify process for identification of transmission constraints and CIL and CEL values when available generation is limiter, not transmission

3 Transfer Analysis

3.1 Calculation Methodology and Process Description

Transfer analysis establishes CILs and CELs for Local Resource Zones (LRZs) in the Planning Reserve Margin (PRM) study for the 2015-2016 Planning Year. The objective of this study is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Significant methodology and process enhancements were put into place prior to Planning Year 2014-15 analysis. The following incremental enhancements were put into place before this year's analysis.

- Improved redispatch for import studies
- Dispatching MISO wind resources to capacity credit levels
- Model topology alignment with MISO Transmission Expansion Plan (MTEP) (LOLE model built for same date as MTEP models)
- Improved and expanded coordination with seam areas
- Expanded redispatch for Reciprocal Coordinated Flowgate (RCF) constraints eligible for market-to-market dispatch
- Thorough modeling review documentation to aid in stakeholder model review

Last year's study included analysis on 5- and 10-year-out models. Considering the importance of pending regulations in the 2016 timeframe, this year's out-year analysis focused on the 2016-17 timeframe.

3.1.1 Tiered generation pools

To determine an LRZ's import or export limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the sink subsystem is the LRZ under study. To reduce the likelihood of remote constraints limiting zonal imports, limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) to the LRZ under study while decreasing generation inside the LRZ under study (Figure 3.1-1).

- Tier 1 – MISO LBAs adjacent to the LRZ under study
- Tier 2 – MISO LBAs adjacent to Tier 1

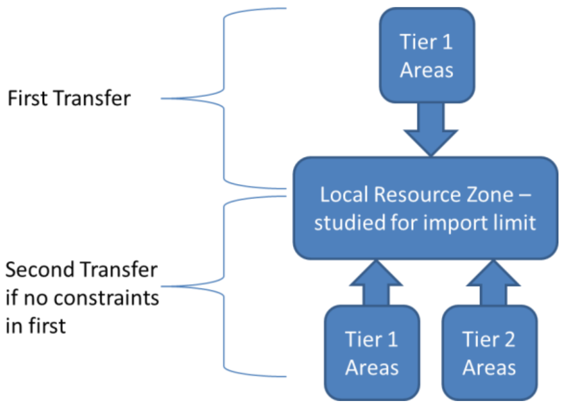


Figure 3.1-1: Tiered import illustration

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 identified using Tier

1 generation, no further analysis is required. If no constraint is identified using Tier 1 available capacity only, available capacity in both Tiers 1 and 2 is then used considering the same redispatch process.

It is not necessary to apply the tiered approach to export studies. Generation within the zone studied for an export limit is being ramped up and constraints are expected to be near the zone because the generation being ramped up is in a more concentrated area than import studies. The opposite is true for import studies – generation outside the study zone is ramped up, which could cause remote constraints limiting local imports if the source pool is large. Using a large source pool also impacts the distribution factors and could potentially mask valid constraints. The sink for export studies is the remaining LRZs.

3.1.2 Redispatch

Redispatch applied in the LOLE study was completed similarly to redispatch for baseline reliability projects, which is referenced in Appendix O, Section O.1.1.1 of the Transmission Planning Business Practice Manual (BPM)[4]. 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 (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units

Each zone's transfer studies might include application of multiple, independent redispatch scenarios depending on the constraints that are identified. Constraints found to be significantly impacted by different units and distant from each other will be redispatched separately.

Redispatch assumptions vary depending on LBA ties for import scenarios (Figure 3.1-2).

Planning Resources eligible to be ramped up	Generation resources eligible to be ramped down
• Source system (Tier 1 or Tiers 1 and 2) • Zone being studied for CIL • External resources for RCF constraints	• All MISO generation resources • External resources for RCF constraints

Figure 3.1-2: Import Redispatch Scenario

For import redispatch scenarios, all MISO generators will be eligible to ramp down if the generation shift factor is 3 percent or higher. Only Planning Resources in the zone and adjacent LBAs will be eligible to ramp up. It is unreasonable to assume ramping down a unit with a significant impact on the constraint by 2 MW, for example, can be offset by ramping up a unit on the other side of the footprint by 2 MW when transmission losses are considered.

[4] BPM 020 – Transmission Planning: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

For export redispatch scenarios, only generation within the zone being studied is considered to be ramped up. Any MISO generator with an impact of 3 percent or higher is eligible to be ramped down (Figure 3.1-3).

Generation resources eligible to be ramped up

- In zone being studied
- External resources for RCF constraints

Generation resources eligible to be ramped down

- All MISO
- External resources for RCF constraints

Figure 3.1-3: Export Redispatch Scenario

3.2 Power Flow Models and Assumptions

3.2.1 Tools used

Siemens PTI Power System Simulator for Engineering (PSS E), Power System Simulator for Managing and Utilizing System Transmission (PSS MUST), and Transmission Adequacy and Reliability Assessment (TARA) were utilized for the transfer analysis.

3.2.2 Inputs required

The study required power flow models and PSS MUST Input files. PSS MUST contingency files from Coordinated Seasonal Assessment (CSA) and MTEP[5] reliability assessment studies were used (Table 3.2-1). Single-element contingencies in MISO and seam areas were evaluated in addition to submitted files.

Model	Contingency files used
2015-16 Planning Year	2014 Summer CSA
2-year-out peak	MTEP14 study

Table 3.2-1: Contingency files per model

[5] Refer to the Transmission Planning BPM for more information regarding MTEP PSS MUST input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

PSS MUST subsystem files include LRZ, Tier 1 and Tier 2 definitions. Refer to Appendix C for maps containing Tiers used for this study. The PSS MUST monitored file includes all facilities under MISO functional control.

3.2.3 Power Flow Modeling

Two summer peak models were required for the analysis: 2015 and 2016. All models were built using MISO's Model on Demand (MOD) model data repository, each with an effective date and base assumptions (Table 3.2-3).

Planning Year	Effective Date	Projects Applied	External Modeling	Load and Generation Profile
2015	7/15/2015	MTEP14 Appendix A and Target A	2013 Series 2015 Summer ERAG MMWG	Summer Peak
2016	7/15/2016	MTEP14 Appendix A and Target A	2013 Series 2016 Summer ERAG MMWG	Summer Peak

Table 3.2-3: Model assumptions

Several types of units were excluded from the transfer analysis dispatch, meaning these units' base dispatch remained fixed in all analyses.

- Dispatch exclusions from the MTEP summer 2014 Coordinated Seasonal Assessment study were applied, which included hydro, nuclear, SVC, motor loads, Behind-the-Meter generation and MISO swing generators
- MISO wind dispatch capped at wind capacity credit, meaning plants could be ramped down to facilitate transfers, but not be ramped up

System conditions such as load, dispatch, topology and interchange have an impact on transfer capability. Stakeholder review of models and input files was requested through LOLEWG meetings and by notices sent to the LOLEWG. Files were made available on the MTEP ftp site. Feedback regarding transmission facilities modeling and ratings and LBA load and generation levels was requested.

3.2.4 General Assumptions

PSS MUST uses the power flow model and associated input files to determine the import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions and is used as an indicator of transmission strength. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3.2-1). All published limits represent the zone's FCTTC.

$$\textit{First Contingency Total Transfer Capability } (FCTTC) = FCITC + \textit{Base Power Transfer}$$

Equation 3.2-1: Total Transfer Capability

Facilities were flagged as potential constraints for loadings of 100 percent or more of the normal rating for North American Electric Reliability Corporation (NERC) Category A conditions and loadings of 100 percent or more of the emergency rating for NERC Category B contingencies. Linear FCITC analysis identifies the limiting constraints using a minimum Distribution Factor (DF) cutoff of 3 percent, meaning the transfer and contingency must increase the loading on the overloaded element by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum 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 model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 3.2-4 and Equation 3.3-2 show 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 (Unit Dispatch Max – Unit Dispatch Min)
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 3.2-4: Example subsystem

$$\boldsymbol{Machine\ 1\ Post\ Transfer\ Dispatch = \frac{Machine\ 1\ Reserve\ MW}{Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW}$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

Equation 3.3-2: Machine 1 dispatch calculation for 100 MW transfer

3.3 Results

The results for each LRZ consists of a list of constraints and the corresponding FCTTC. Invalid constraints were identified for several reasons, such as outdated ratings, invalid contingencies, solution tolerance settings, invalid external base dispatch, or associated operating guides that mitigate the constraint. The CIL and CEL are the FCTTC of the corresponding limiting constraint. Section 5.2.2.3 of the Resource Adequacy BPM provides additional information regarding how the CIL impacts the Local Clearing Requirement calculation. Constraints and associated limits were presented and reviewed through the LOLEWG. This activity occurred in the meetings that took place in August through October 2014.

Significant stakeholder feedback that resulted in updated limits includes:

- LRZ 2 CIL constraint to be on outage during summer period
- AMMO units physically located in Illinois need to be modeled in AMIL LBA
- External base model and redispatch adjustments
- More effective redispatch scenarios

Sensitivity analysis was performed on LRZ 2's CIL to determine the impact of a long-term outage and the retirement of Nelson Dewey generation during the Planning Year. The limit was significantly impacted by both the outage and the retirement. Since it is possible the outage might end earlier than planned and be in-service during the summer timeframe, the final value was determined with the transmission line in-service. The unit retires several months after the summer peak period, so it was decided to include it in the summer peak model.

Last year's LOLE out-year analysis focused on five- and 10-year-out analyses to align with MTEP timeframes and modeling data. This year's study focused on a two-year-out model due to impactful regulations in the 2016-17 horizon.

Detailed constraint and redispatch information for all limits is found in Appendix C: Transfer Analysis of this report. A summary of the Planning Year 2015-16 Capacity Import Limits is in Table 3.3-1.

Zone	Tier	15-16 Limit (MW)[6]	Monitored Element	Contingent Element	Figure 3.3-1 Map ID	Initial Limit (MW)[7]	Generation Redispatch Details		14-15 Limit (MW)
							MW	Area(s)	
1	1	3,735	Worth County – Colby 161kV	Barton – Adams 161 kV	1	3,376	2,000	MEC, ITCM, XEL, & GRE	4,347
2	1	2,903	Turkey River – Stoneman 161kV	AT5/7 Xfr fault	2	2,104	694	WEC, ALTE, MGE, & ALTW	3,083
3	1	1,972	Palmyra 345/161 kV transformer	Hills – Sub T – Louisa 345 kV	3	727	2,000	XEL, ALTW, & MEC	1,591
4	1	3,130	Tazewell 345/138 kV transformer 1	Tazewell 345/138 kV transformer 2	4	850	2,000	NIPS, BREC, AMMO, AMIL, ITCM, & MEC	3,025
5	1	3,899	White Bluff – Keo 500kV	Sheridan – Mabelvale 500kV	5	3,899	Not Applicable		5,273
6	1&2	5,649	Neoga – Holland 345kV	Xenia – Mount Vernon 345kV	6	5,090	2,000	METC & AMIL	4,834
7	1&2	3,813	Clifty Creek – Trimble County 345kV	Rockport – Jefferson 765kV	7	2,412	Not Applicable		3,884
8	1	2,074	Mt Olive – Vienna 115kV	Mt Olive – Eldorado 500 kV	8	482	2,000	CLEC, AMMO, & EES	1,602
9	1	3,320	Junction City to Bernice 115kV	Mount Olive to El Dorado 500kV	9	3,320	Not applicable		3,585

Table 3.3-1: Planning Year 2015–2016 Capacity Import Limits

[6] The 15-16 Limit represents the limit after redispatch has been considered.
[7] The Initial Limit represents the limit before considering redispatch.

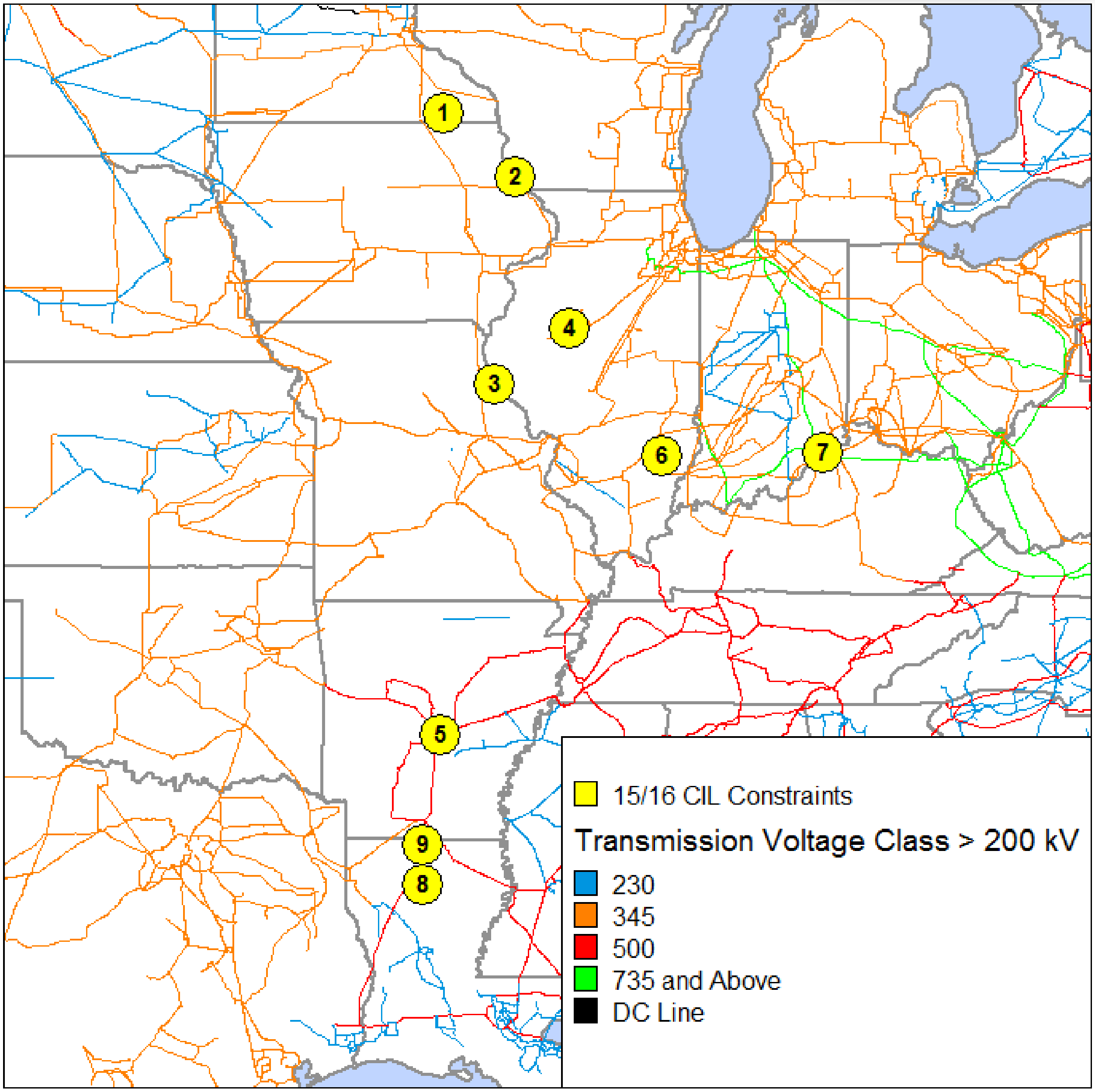


Figure 3.3-1: Planning Year 2015-16 CIL constraint map

Capacity Exports Limits were found by increasing generation in the zone under study and decreasing generation in the rest of the MISO footprint. Table 3.3-2 summarizes Planning Year 2015-16 Capacity Export Limits.

Zone	15-16 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-2 Map ID	Initial Limit (MW)	Generation Redispatch Details		14-15 Limit (MW)
						MW	Area	
1	604	Lakefield – Dickinson 161 kV	Webster 345 kV Station	1	604	Not Applicable		286
2	1,516	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	2	1,167	1,188	WEC, MGE, ALTE, & CE	1,924
3	1,477	Byron – Cherry Valley 345kV Red	Byron – Cherry Valley 345kV Blue	3	648	1,610	MEC, NIPS, & WEC	1,875
4	4,125	Hutsonville – Robinson 138kV	Newton – Robinson 138kV	4	4,125	Not Applicable		1,961
5	0[8]	Palmyra 345/161 kV Transformer	Hills – Sub T – Louisa 345 kV	5	0	Not Applicable		1,350
6	2,930	Clifty Creek – Trimble County 345kV	Rockport – Jefferson 765kV	6	2,930	Not Applicable		2,246
7	4,804	Benton Harbor 345/138 kV Transformer	Benton Harbor – Cook 345 kV	7	4,799	53	METC & ITCT	4,517
8	3,022	Woodward – Stuttgart Ricusky 230kV	Keo – West Memphis 500kV	8	2,767	2,000	EAI	3,080
9	3,239	White Bluff – Keo 500kV	Sheridan – Mabelvale 500kV	9	951	2,000	EES & CLEC	3,616

Table 3.3-2: Planning Year 2015–2016 Capacity Export Limits

[8] Limit is initially determined by transmission constraint listed above, then is limited by generation

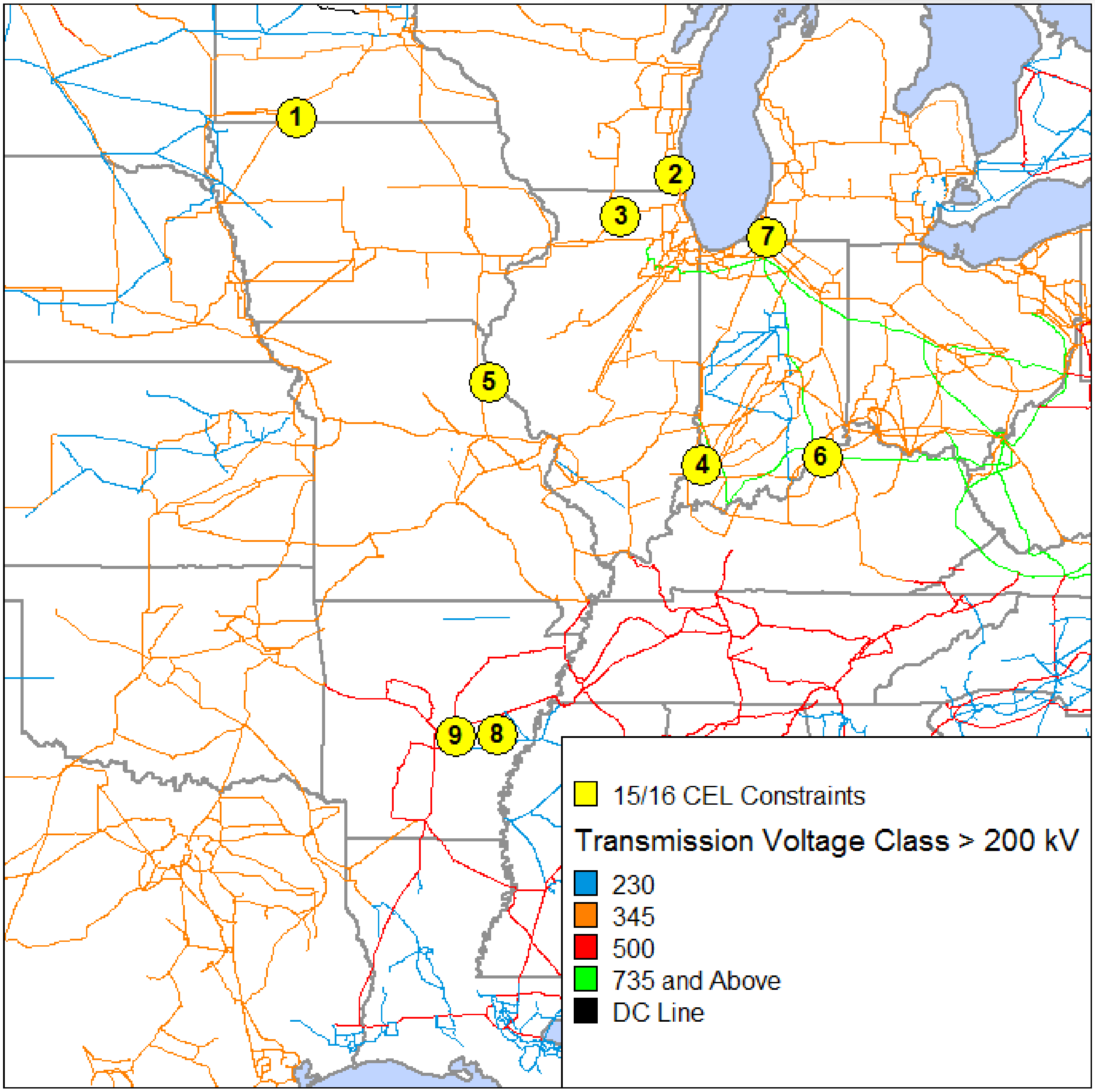


Figure 3.3-2: Planning Year 2015-16 CEL constraint map

3.3.2 2016-17 Results

Table 3.3-3 summarizes 2016-17 Capacity Import Limits.

Zone	Tier	2016-17 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-3 Map ID	Initial Limit (MW)	Generation Redispatch Details	
							MW	Area(s)
1	1	3,453	Worth County – Colby 161 kV	Barton – Adams 161 kV	1	3,430	2,000	MEC, ITCM, XEL, GRE
2	1	3,586	Turkey River – Stoneman 161 kV	Seneca – Genoa 161 kV	2	1,362	2,000	ITCM, ALTE, ALTW, MGE, MEC
3	1	3,711	Palmyra 345/161 kV Transformer	Louisa – Sub T to Hills 161 kV	3	787	2,000	XEL, ALTW, AMIL, AMMO, MEC
4	1	1,931	West Point – Lafayette 230 kV	Eugene – Cayuga 345 kV	4	675	2,000	DEI, NIPS, AMMO, MEC, ITCM, XEL
5	1	3,991	White Bluff – Keo 500 kV	Sheridan – Mabelvale 500 kV	5	3,131	2,000	EAI, AMIL, AMMO
6	1&2	5,389	Newton – Casey 345 kV	Casey – Neoga 345 kV	6	4,497	2,000	METC, AMIL
7	1&2	3,666	Battle Creek – Argenta 345 kV	Argenta – Tompkins 345 kV	7	2,820	2,000	EES, ALTE, AMIL, WEC, DEI
8	1	2,441	Montgomery – Clarence 230 kV	Montgomery – Winnfield 230 kV	8	0	2,000	AMMO, EES, LAGN, CLEC
9	1	3,193	Junction City – Bernice 115 kV	Mount Olive – El Dorado 500 kV	8	3,193	Not Applicable	

Table 3.3-3: 2016-17 Capacity Import Limits

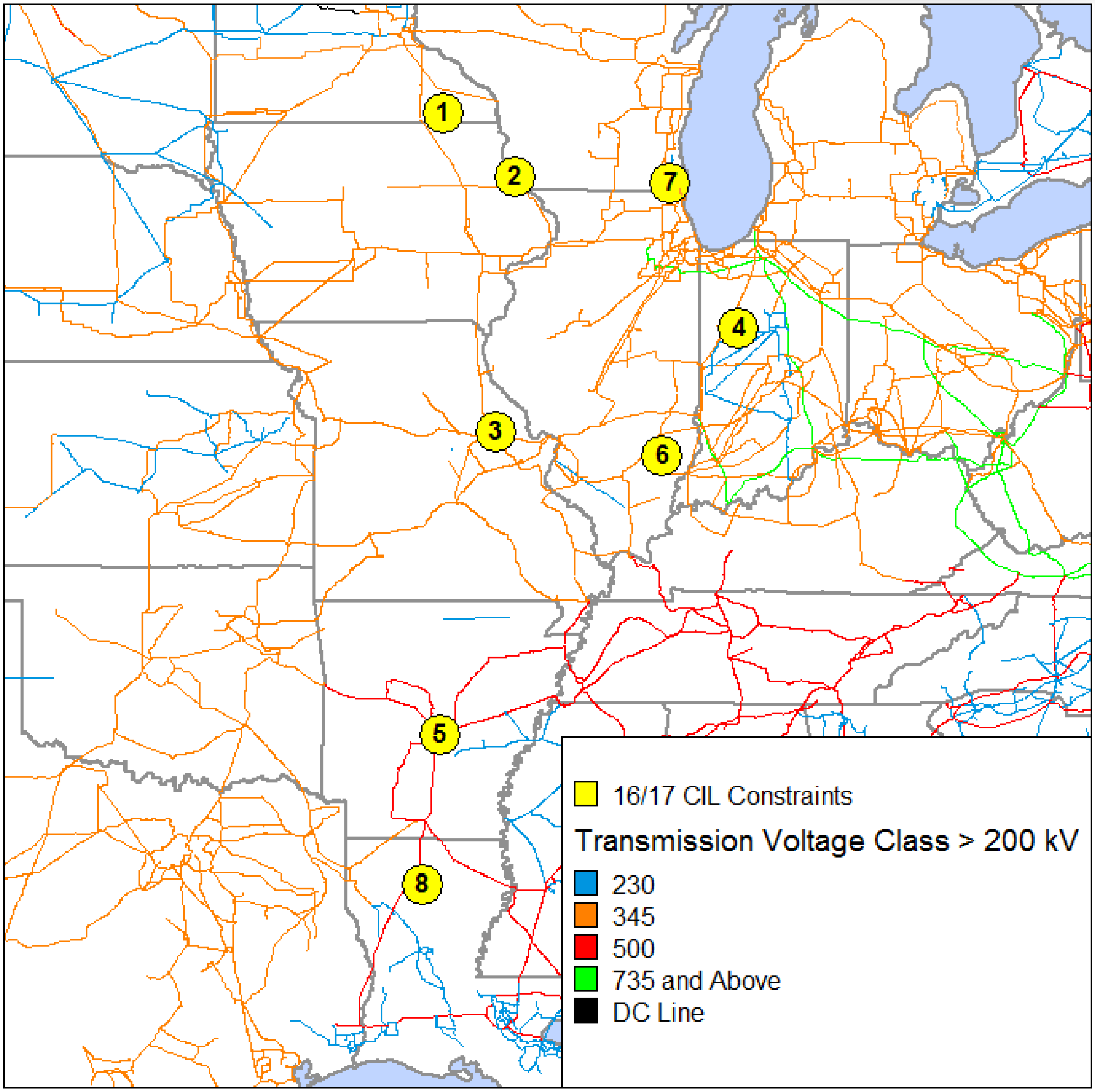


Figure 3.3-3: 2016-17 CIL map

Table 3.3-4 summarizes 2016-17 Capacity Export Limits.

Zone	2016-17 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-4 Map ID	Initial Limit (MW)	Generation Redispatch Details	
						MW	Area(s)
1	350	Byron – Cherry Valley Red 345 kV Line	Byron – Cherry Valley Blue 345 kV Line	1	0	2,000	XEL, SMMPA, GRE, ITCM, MEC, DPC
2	1,858	Zion Energy Center – Zion Station 345 kV Line	Zion Station – Pleasant Prairie 345 kV Line	2	867	2,000	WEC, MGE, ALTE, CE
3	1,983	Palmyra Transformer 345/161 kV Transformer	Montgomery – Spencer 230 kV Line	3	869	1,184	ALTW, MEC, MPW, AMMO
4	3,793	Jacksonville – Westchester 138 kV	Meredosia – Alsey PPI 138 kV Line	4	3,793	Not Applicable	
5	0[9]	Palmyra Transformer 345/161 kV Transformer	Hull – South Quincy 138 kV Line	3	0	Not Applicable	
6	2,360	Westpoint – Lafayette 230 kV Line	Eugene – Clay Sub 345 kV Line	5	2,360	Not Applicable	
7	3,399	Dorr Corners Jct – Beals 138 kV Line	Argenta – Tallmadge 345 kV Line	6	3,399	Not Applicable	
8	3,494	Hot Springs East Bus – Butterfield 115 kV Line	Sheridan – Magnet Cove 500 kV Line	7	2,761	2,000	EES
9	2,511	Montgomery – Clarence 230 kV Line	Montgomery – Winnfield 230 kV Line	8	1,678	1,133	EES, CLEC

Table 3.3-4: 2016-17 Capacity Export Limits

[9] Limit is initially determined by transmission constraint listed above, then is limited by generation

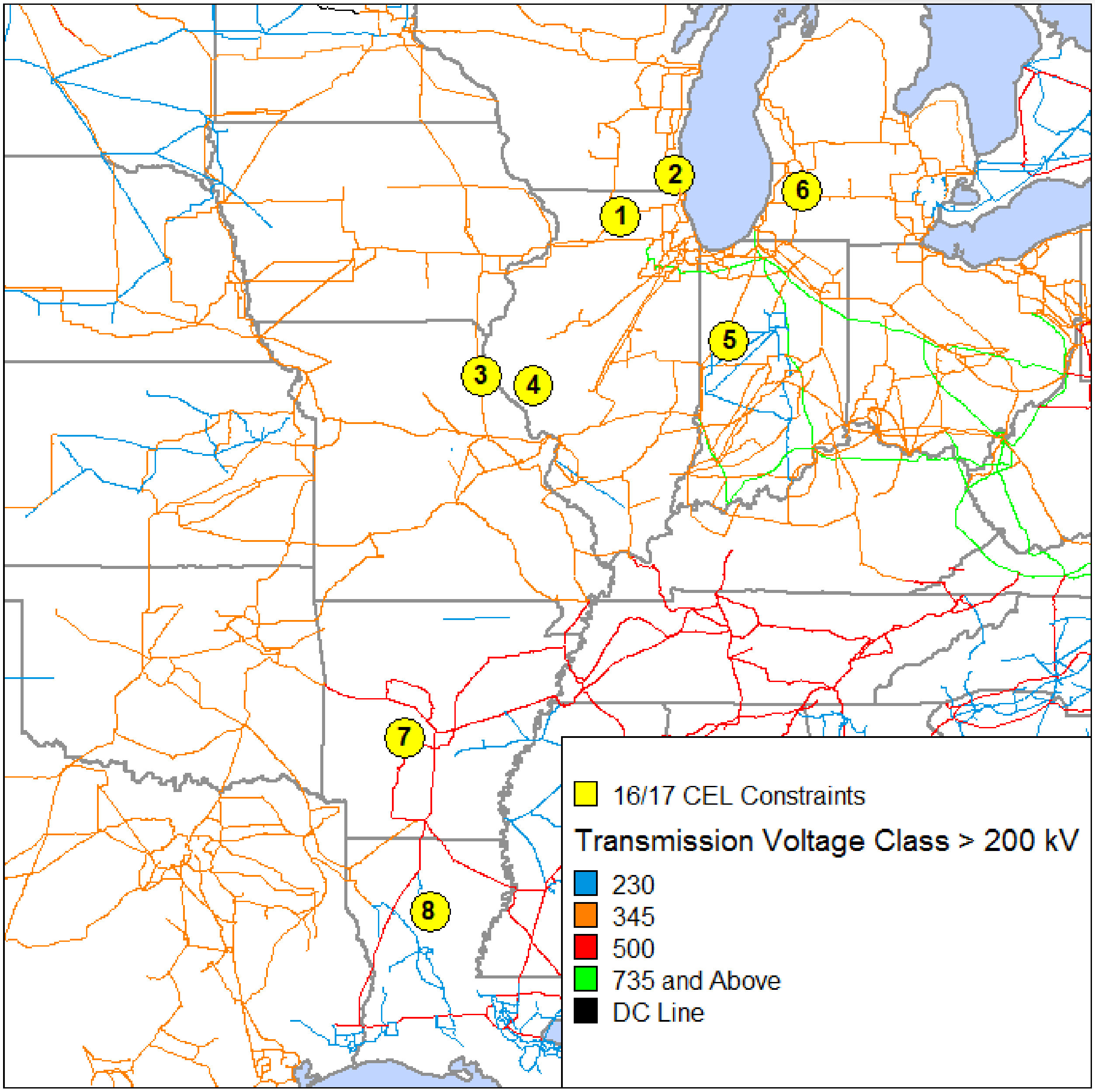


Figure 3.3-4: 2016-17 CEL map

4 Loss of Load Expectation (LOLE) Analysis

4.1 LOLE Modeling Input Data and Assumptions

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation (MARS) to calculate the LOLE for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS calculates the annual LOLE for the MISO system and each Local Resource Zone (LRZ) by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

The GE MARS model builds are the most time-consuming tasks of the Planning Reserve Margin (PRM) study. Many cases are built to model different scenarios and to determine how certain variables impact the results. The base case models determine the MISO PRM ICAP, PRM UCAP and the Local Reliability Requirements (LRR) for each LRZ for years one, two and three and the PRM values for year 10.

4.2 MISO Generation

4.2.1 Thermal Units

The 2015-2016 planning year LOLE study utilized the 2014 PRA converted capacity as a starting point for which resources to include in the study. This was to better align the LOLE study with the Planning Resource Auction to ensure that only resources eligible as a Planning Resource were included. An exception was made for those resources in MISO's March 2014 Commercial Model that weren't part of the 2014 PRA but stated in the 2015 OMS-MISO Survey that they would be available in 2015. These resources were also included. All internal Planning Resources were modeled in the LRZ that they are physically located in.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2009 to December 2013) and modeled as one value. Some units did not have five years of historical data in PowerGADS, but if they had at least 12 consecutive months of data then unit-specific information was used. If a unit had less than 12 consecutive months of unit-specific data in PowerGADS, then that unit was assigned the corresponding MISO class average forced outage rate and planned maintenance factor. If a particular MISO class had less than 30 units, then the overall MISO weighted class average forced outage rate of 7.67 percent was used.

Nuclear units have a fixed maintenance schedule, which was pulled from Ventyx PowerBase and was modeled for each of the study years.

4.2.2 Behind-the-Meter Generation

Behind-the-Meter generation data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate.

4.2.3 Sales

This year's LOLE analysis incorporated firm sales to PJM. For units with capacity being sold to PJM, the monthly capacities were reduced by the megawatt amount being sold. This totaled 2,044 MW for Planning Year 2015-2016 and 4,135 MW for Planning Year 2016-2017 and 3,368 Planning Years 2017-2018 and 2024-2025. These values came from PJM's Reliability Pricing Model (RPM).

4.2.4 Attachment Y

For the 2015-2016 Planning Year, generating units that have approved suspensions or retirements (as of May 9, 2014) through MISO's Attachment Y process are accounted for in the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the Planning Year was excluded from the year-one analysis.

For the year two-, three- and 10-year analyses, all units that have submitted an attachment Y request for suspension or retirement are removed, as are units indicating plans to retire in the EPA Survey. However, if a unit indicated in the OMS-MISO survey that it would be returning from suspension for 2016 and beyond then it was modeled as in service at the time of the suspension end date.

2015 PRM Study	PY 2015-2016	PY 2016-2017	PY 2017-2018	PY 2024-2025
Capacity Not Included in LOLE Model	**Year 1**	**Year 2**	**Year 3**	**Year 10**
Attachment Y - Approved	X	X	X	X
Attachment Y - Under Study		X	X	X
Attachment Y2's also in EPA Survey		X	X	X
EPA Survey Retirements		X	X	X

Table 4.2-1: Retirement and suspension assumptions

4.2.5 Future Generation

Future thermal generation and upgrades were added based on unit information in the MISO Generator Interconnection Queue. Only units with a signed interconnection agreement (as of May 9, 2014) were included in the LOLE model. These new units were assigned class-average forced outage rates and planned maintenance factors based on their particular unit class. Units that were upgraded during the study period reflected the MW increase for each month beginning the month the upgrade was finished. Future wind generation was not included in the LOLE analysis.

4.2.6 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources such as run-of-river hydro and biomass provide MISO with up to 15 years of historical summer output data during hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as unforced capacity for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind-generator CPNode received a capacity credit based on its historical output from MISO's top eight peak days in each past year for which data was available. The megawatt value corresponding to each CPNode's wind capacity credit was used for each month of the year. If a unit was new to the commercial model and did not receive a wind capacity credit as part of the 2014 Wind Capacity Credit analysis, then that unit was given the MISO-wide wind capacity credit of 14.1 percent as established by the 2014 Wind Capacity Credit Effective Load Carrying Capability (ELCC) analysis. The capacity credit established by the ELCC analysis determines the maximum percent of the wind unit that can receive credit in the PRA while the actual amount could be less. Each wind CPNode receives its actual wind capacity credit based on the capacity eligible to participate in the PRA. Only Network Resource Interconnection Service or Energy Resource Interconnection Service with firm point-to-point is considered an eligible capacity resource. The final value from the 2014 PRA for each wind unit was modeled at a flat capacity profile for the Planning Year. Aggregate megawatt values for wind generating units are then determined for MISO and each LRZ. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2014 Wind Capacity Credit Report.

4.2.6 Demand Response

Demand response data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled as energy-limited resources. Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration.

4.3 MISO Load Data

For the 2015-2016 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by Load Serving Entities (LSE) through the MECT tool. The non-coincident peak demand forecasts (with transmission losses) by LSEs were aggregated by their respective Local Balancing Authorities (LBA) and applied to the LBA's historical load shape in GE MARS. LRZs 1 through 7 used the 2005 historical load shape while zones 8 and 9 used the 2006 historical load shape. For MISO North/Central, the 2005 load shape is typical for the area as well as typical for external areas. With the integration of MISO South, MISO chose to use the 2006 historical shape as the 2005 shape represented an extreme weather year for the South region due to Hurricane Katrina. In GE MARS, MISO utilized the ability to input monthly peaks, which MARS used to modify the historical load shape accordingly in order to adhere to the monthly peak forecasts that LSEs submitted. These are shown as the MISO System Peak Demand in Table 5.1-1 and LRZ Peak Demands in Table 6.1-1.

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

4.3.1 Load Forecast Uncertainty

Load Forecast Uncertainty (LFU), a standard deviation statistical coefficient, is applied to base 50/50 load forecast to represent the various probabilistic load levels. With transition into Module E1 in 2012, MISO determines two separate requirements: Local Reliability Requirement (LRR) for each zone as well as an overall MISO-wide Planning Reserve Margin (PRM).

- For the 2013 LOLE study, MISO began calculating LFU for each Local Resource Zone (LRZ) to derive the LRR by applying the NERC Bandwidth Method to associated zonal historic demand.
- In addition to that, a MISO-wide LFU was calculated and applied to an aggregate MISO load shape to determine a MISO-wide PRM. In the current LOLE study, enhancements were made to this LFU determination.

Through previous years' analysis results, it was determined that aggregating the MISO-wide footprint (including MISO South) into one load shape was no longer prudent in derivation of the MISO-wide PRM given the large geographic footprint. A MISO-wide LFU applied to every load in MISO, regardless of its unique LFU and geographic location, misrepresents the local uncertainty in demand. The misrepresentation of local uncertainty in demand is amplified when applying the old method to such a large geographic area.

In the 2014 LOLE study, MISO identified a new modeling technique, which connected each LRZ to a central hub with infinite ties. This enabled MISO to model each LRZs demand and generation uniquely.

Use of this method to derive the MISO-wide PRM better aligns with the zonal construct. For this year's study, MISO continued using the updated modeling method. The resulting LFU, through modeling in a probabilistic model, was determined to be 3.8 percent for the aggregate MISO footprint, which is in line with previously derived LFU. Further details of this determination are discussed later in this section.

This method ensures that the LRZ LRR is established in sync with MISO-wide PRM using the same model and applying the same zonal LFUs. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load. This application of LFU more accurately reflects the uncertainty impacts of each LRZ's geographic area.

In the zonal methodology, MARS applied the LFU of each LRZ to its corresponding hourly load; this application was not limited only to the peak loads. In other words, at every specific hour in the model, if one LRZ was taken away from its 50/50 load of that hour by one standard deviation (sigma), all other zones were one sigma away from their 50/50 loads of that very same hour, where the sigma value was a different value of LFU for each LRZ. The LRZ LFU values used in the MISO PRM analysis are provided in Table 4.3-1.

Zones	LFU
LRZ 1	2.8%
LRZ 2	4.5%
LRZ 3	2.9%
LRZ 4	4.5%
LRZ 5	4.2%
LRZ 6	3.3%
LRZ 7	5.2%
LRZ 8	4.9%
LRZ 9	3.1%

Table 4.3-1: 2015 Local Resource Zone LFU

As discussed previously, MISO back-calculated the system wide LFU equivalent to MISO's current zonal methodology to be about 3.8 percent. In this calculation, the 50/50 hourly load of each LRZ was increased by one standard deviation and then aggregated up to get to one hourly load for the MISO footprint. This load was compared to the 50/50 MISO hourly load and the overall LFU for every hour was calculated. The average of these hourly MISO LFUs was about 3.8 percent.

Previously, MISO performed LFU sensitivity analysis to examine its effect on the Planning Reserve Margin Requirement. MISO concluded that for the LFU ranges of 3 percent to 4 percent, a 1 percentage point increase in LFU contributes to an increase of about 2 percentage points in PRM UCAP.

As promised during previous years' study, MISO started a Load Forecast Uncertainty Task Team as a MISO stakeholder forum to discuss possible improvements to the LFU calculation. Due to low stakeholder involvement, stability in the results of LFU calculation, and comparison with the industry practices, the

LOLEWG decided to stop meeting through that forum. It opted to continue with the current methodology and bring any LFU-related concern or recommendation to the LOLEWG going forward.

More details about the LFU methodology are provided in Appendix A: Load Forecast Uncertainty.

4.4 External System

The LOLE study utilized an external model with seven external zones. In order to determine an appropriate level of support that MISO could expect from the external systems, each external zone was modeled at its appropriate target PRM with adjustments for sales/purchases and demand-side management (DSM) program reductions. The tie capacity value to each external zone was derived from an analysis of the 2013 Historical Net Scheduled Interchange (NSI) data. MISO South companies provided the NSI data separately since MISO did not collect the NSI data prior to MISO South integration on December 19, 2013. This data was merged with the MISO North/Central NSI data to determine the total tie capacity values to each external zone. The LOLE model probabilistically determines reasonable external assistance and reduction in the PRM from being interconnected to external entities.

4.4.1 Development of the External Model Import Tie Capability

The total tie limits for the external model were derived from observing the hourly historical maximum NSI between MISO and each first-tier balancing authority (BA) during North American Energy Standards Board (NAESB)-designated summer peak hours. NAESB summer peak hours are defined as 0800 to 2300 EST Hour Ending, Monday through Saturday, and in the months June through August. Previous LOLE studies determined NSI values over the entire year. The move to summer peak hours more accurately reflects available external support in a MISO peak demand scenario when a loss-of-load event is most likely to occur. The 2013 NSI data was analyzed for the 2015-2016 LOLE analysis. The 17 first-tier BAs' historical NSI values were merged into seven equivalent external zones that would mirror limits to adjacent Regional Transmission Operators (RTO), power pools, or Reliability Coordinators. Figure 4.4-1 shows the BA breakdown of these seven external zones. When determining the MISO PRM, all external purchases are modeled as firm non-curtailable contracts from the respective external zone to MISO. MARS will account for the firm contracts when calculating available flow on the tie lines. In the LRZ LRR model, in contrast, external purchases are not modeled as the zone is treated as an island. The zonal UCAP values shown in Table 6.1-1 only reflect generation that is internal to that zone and does not account for generation claimed from outside MISO.

External Zone	NERC Acronym	2013 17 MISO 1st Tier Balancing Authorities Reflecting 2015 Footprint
External Zone A	WAUE	Western Area Power Administration-Upper Great Plains Region
External Zone B	MHEB	Manitoba Hydro
	SPC	Saskatchewan Power Co.
External Zone C	PJM	Pennsylvania-NewJersey-Maryland Interconnection
External Zone D	ONT	IESO (Independent Electricity System Operator)
External Zone E	MOWR	Westar Energy Resources/Missouri Joint Municipal Electric Utility Commission
	SPA	Southwestern Power Administration
	SWPP	Southwest Power Pool
	AEP	American Electric Power Company (formerly Central and South West Services)
	OKGE	Oklahoma Gas & Electric Company
	EDE	Empire District Electric
External Zone F	SOCO	Southern Company
External Zone G	LGEE	Louisville Gas and Electric
	TVA	Tennessee Valley Authority
	EEI	Electric Energy Incorporated
	AEC	Appalachian Electric Coop.
	AECI	Associated Electric Cooperative Inc.

Figure 4.4-1: MISO first-tier Balancing Authorities with external purchases

4.4.2 External Zones Base PRM and Adjustments

For the external zones, all load and generator data came from vendor-supplied databases since MISO only collects detailed information on MISO load and generation resources. MISO then set the available generation for each external zone at its reported planning reserve margins. If a regional PRM was not established, MISO used the NERC reference margin of 15 percent. The target PRM for PJM was set based on the reserve margin cleared in the Reliability Pricing Model auctions. This margin is higher than its Planning Reserve Margin calculated in its Reserve Requirement Study (RRS), which is similar to the MISO LOLE Study. This was an improvement from last year as capacity cleared in PJM's RPM has capacity obligations for the corresponding planning year they clear in.

The target PRM for each external zone was then increased by external purchases from that zone. External purchases are external resources claimed in MECT for the 2014-2015 Planning Year. In the 2014 Planning Resource Auction, the declared external resources in MECT totaled 3,155 MW. External sales have the inverse relationship to purchases and decreased the external regions target PRM. Only MISO capacity sold in PJM's Reliability Pricing Model (RPM) was modeled. PJM is the only external area with a capacity market that has must-offer obligations. This will be evaluated annually to determine if other external areas begin to have capacity markets. For units with capacity being sold to PJM, the monthly capacities were reduced by the megawatt amount being sold. This totaled 2,044 MW for Planning Year 2015-2016 and 4,135 MW for Planning Year 2016-2017 and 3,368 Planning Years 2017-2018 and 2024-2025.

To more accurately model operational characteristics in times of peak demand the external zones corresponding DSM was removed from its available capacity, effectively reducing the target PRM. External zones DSM program data was taken from the 2013 NERC Long-Term Reliability Assessment. Table 4.4-1 itemizes each external zone's base PRM, purchases, sales and DSM programs by planning year.

External Area-ID	PRM Target Base (%)				MISO Firm External Purchases (MW)	External DSM (MW)			
	2015PY	2016PY	2017PY	2024PY	All Years	2015PY	2016PY	2017PY	2024PY
ExA-MRO	15.0%	15.0%	15.0%	15.0%	402	106	108	110	122
ExB-MHEB	12.0%	12.0%	12.0%	12.0%	908	308	308	308	308
ExC-PJM	19.3%	20.3%	19.7%	19.7%	535	14,833	12,408	10,975	10,975
ExD-IESO	18.7%	18.0%	19.1%	20.0%	0	567	567	567	567
ExE-SPP	13.6%	13.6%	13.6%	13.6%	87	1,275	1,329	1,281	1,541
ExF-SOCO	15.0%	15.0%	15.0%	15.0%	0	2,249	2,267	2,278	2,302
ExG-SERC	15.0%	15.0%	15.0%	15.0%	1,223	2,006	2,195	2,339	3,107
Total					**3,155**	**21,344**	**19,182**	**17,858**	**18,922**

Table 4.4-1: External Zones PRM Targets

The historic 7,661 MW value shown in Figure 4.4- was the maximum simultaneous import flow in 2013, which sets the limit that the model allows into MISO. Other maximum non-simultaneous values from each of the external zones are also shown. For example, 1,200 MW is the non-simultaneous limit from the external zone “ExE-SPP.” ExE-SPP is also a merged zone, since it is a zone derived from observing the historical first-tier NSI from six BAs.

Features in the LOLE simulation can simultaneously track the supporting flows up to a zone’s individual non-simultaneous maximum flow from a BA (indicated in red in Figure 4.4-2) and also limit the support amount to a lower level as dictated by the simultaneous sum combinations (indicated by the grouped simultaneous values in blue font). The 7,661 MW limit in blue font is the overall MISO simultaneous limit.

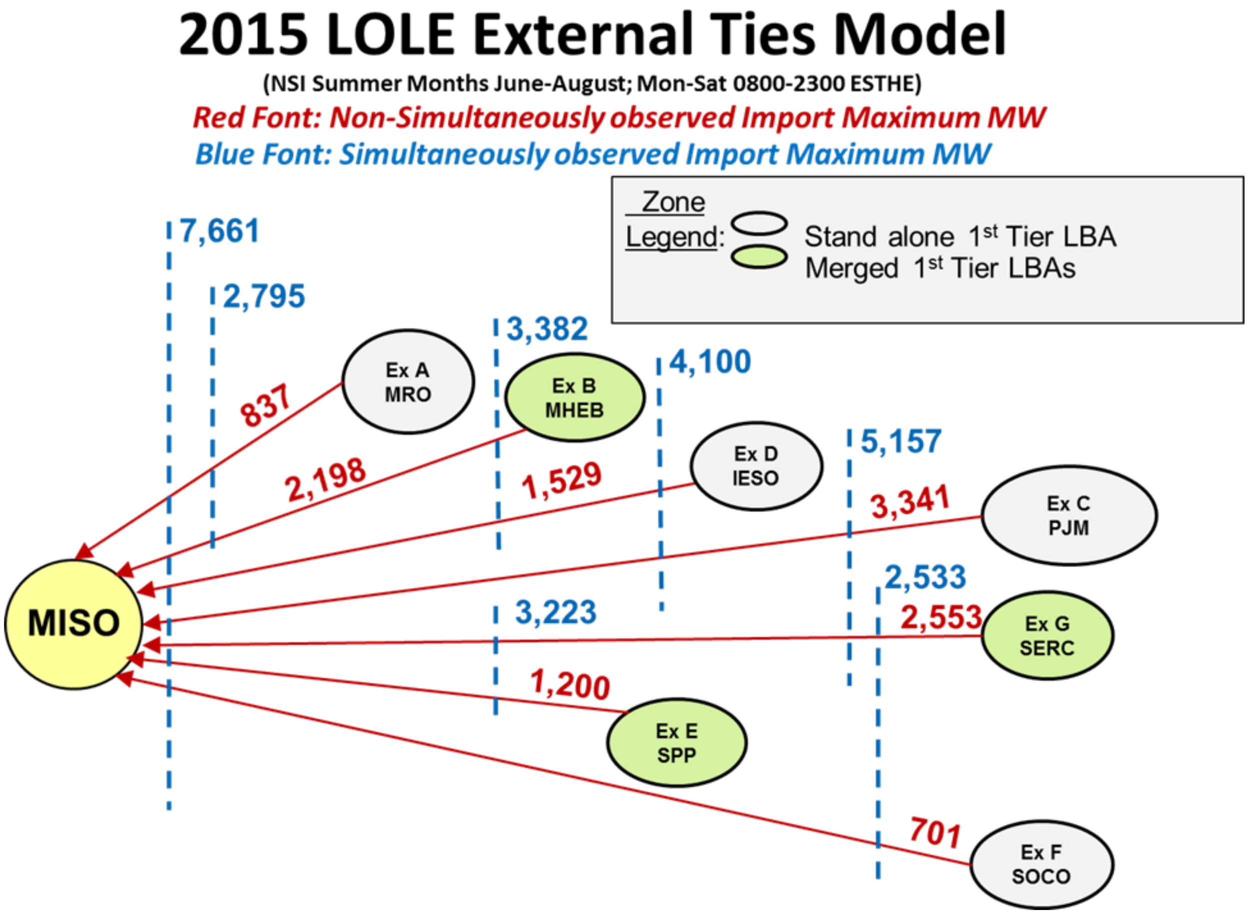


Figure 4.4-2: MISO first-tier Balancing Authorities with external purchases

4.5 Loss of Load Expectation Analysis and Metric Calculations

Once the GE MARS input files were created, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2015-2016 Planning Year as well as the appropriate Local Reliability Requirement for each of the nine LRZs. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

4.5.1 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations with external transmission ties to MISO's first tier BAs. In order to meet the reliability criteria of 0.1 days per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

For the 2015-2016 planning year, MISO had enough capacity to meet a LOLE of 0.1 days per year. In order to achieve a LOLE of 0.1 days per year, unforced capacity had to be removed from the MISO pool. This was done following an iterative process of removing the units with the smallest unforced capacity until MISO reached a LOLE of 0.1 days per year. The last unit removed was not completely removed but derated to a point where the reliability criterion was met.

The formulas for the PRM values for the MISO system are:

PRM ICAP = (Installed Capacity + Firm External Support + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP = (Unforced Capacity + Firm External Support + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

4.5.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ and was modeled without consideration of the benefit of the LRZ's Capacity Import Limit. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 days per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

For the 2015-2016 planning year, three LRZs had enough capacity to meet a LOLE of 0.1 days per year. In order to determine the LRR for these LRZs, unforced capacity had to be removed. This was done following an iterative process of removing the units with the smallest unforced capacity until the LOLE was 0.1 day per year for the LRZ. Typically, the last unit removed was not completely removed but derated to a point where the reliability criterion was met.

Proxy units of typical size (160 MW) and class average EFORd (5.61 percent) were added to an LRZ when there was not sufficient unforced capacity within the LRZ to achieve the LOLE of 0.1 day per year. A fraction of the final proxy unit was added to achieve exactly the LOLE of 0.1 day per year for the LRZ. Six LRZs were short capacity to meet 0.1 days per year LOLE and needed proxy units added.

The formula for the LRR for a given LRZ (*e.g.*, LRZ_{z1}) is:

LRR_{z1} = (largest Unforced Capacity rated $unit_{z1}$ + 2nd largest Unforced Capacity rated $unit_{z1}$ + 3rd largest Unforced Capacity rated $unit_{z1}$ + …, including, if necessary, any proxy units) such that the $LOLE_{z1}$ = 0.1 day per year

A per-unit LRR was then calculated because the actual demand forecasts will not be known until the 2015 Planning Resource Auction takes place in April 2015.

The formula for the per-unit LRR for a given LRZ (*e.g.*, LRZ_{z1}) is:

Per-Unit LRR_{z1} = LRR_{z1}/ LRZ_{z1} Peak Demand in Study Model

5 MISO System Planning Reserve Margin Results

5.1 Planning Year 2015-2016 MISO Planning Reserve Margin Results

For the 2015-2016 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning installed capacity (ICAP) reserve margin of 14.3 percent and a planning unforced capacity (UCAP) reserve margin of 7.1 percent. These PRM values assume 3,155 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. The non-firm support is determined by running a case without the external system to establish the Planning Reserve Margin requirement without help from the external world. The difference between this case and the base case shows the approximate average non-firm support the MISO system is receiving. Table 5.1-1 shows all the values and the calculations that went into determining the MISO system PRM ICAP and PRM UCAP.

MISO Planning Reserve Margin (PRM)	2015/2016 PY (June 2015 - May 2016)	Formula Key
MISO System Peak Demand (MW)	127,586	[A]
Time of System Peak (EST)	8/5/2015 16:00	
Installed Capacity (ICAP) (MW)	152,616	[B]
Unforced Capacity (UCAP) (MW)	142,006	[C]
Firm External Support (MW)	3,155	[D]
Adjustment to ICAP (MW)	-9,995	[E]
Adjustment to UCAP (MW)	-8,532	[F]
ICAP PRM Requirement (PRMR) (MW)	145,775	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	136,628	[H]=[C]+[D]+[F]
MISO PRM ICAP	**14.3%**	[I]=([G]-[A])/[A]
MISO PRM UCAP	**7.1%**	[J]=([H]-[A])/[A]

Table 5.1-1: Planning Year 2014-2015 MISO System Planning Reserve Margins

5.2 Comparison of PRM Targets Across Six Years

Figure 5.2-1 compares the PRM UCAP values over the last six planning years. The last endpoint of the green line shows the Planning Year 2015-2016 PRM value.

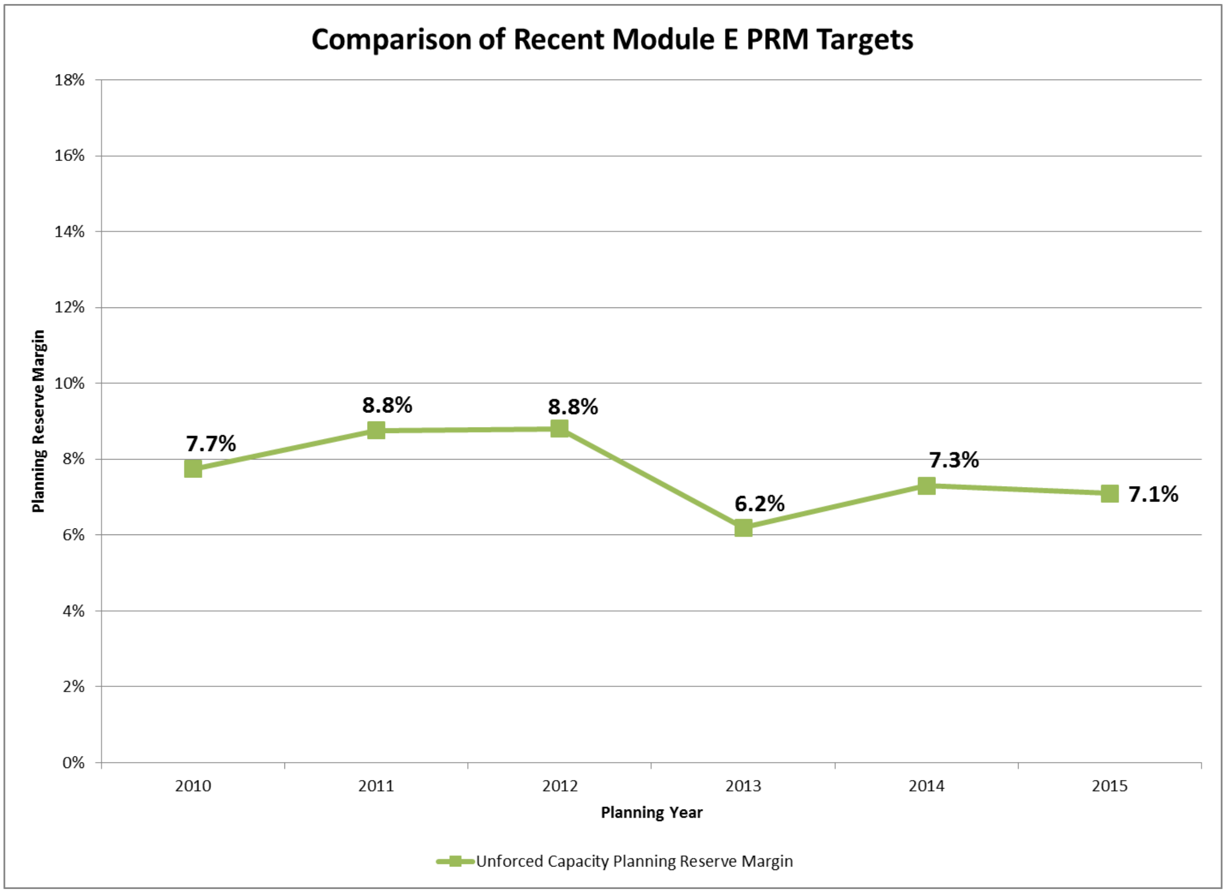


Figure 5.2-1: Comparison of PRM targets across six years

5.3 Future Years 2016 through 2024 Planning Reserve Margins

Beyond the planning year 2015-2016 LOLE study analysis, an LOLE analysis was performed for the two-year-out planning year of 2016-2017, three-year out planning year of 2017-2018 and the 10-year-out planning year of 2024-2025. Table 5.3-1 shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the red-font values of Table 5.3-2. The years in between were arrived at through interpolation of the results from the years 2015, 2016, 2017 and 2025. Note that the MISO system PRM results assume no limitations on transfers within MISO.

In future years, MISO sees stability in the PRM UCAP, which is driven by MISO's assumption of constant LFU in out years. The 2024 PRM UCAP is lower than previous years due to the fact that capacity has to be added to the MISO system to meet the LOLE criterion of 0.1 days/year. This causes the resource mix to have a slightly better overall system weighted forced outage rate, which is driving the PRM UCAP down.

MISO Planning Reserve Margin (PRM)	2016/2017 PY (June 2016 - May 2017)	2017/2018 PY (June 2017 - May 2018)	2024/2025 PY (June 2024 - May 2025)	Formula Key
MISO System Peak Demand (MW)	129,367	130,690	138,091	[A]
Time of System Peak (EST)	8/3/2016 16:00	8/2/2017 16:00	7/31/2024 16:00	
Installed Capacity (ICAP) (MW)	148,909	150,398	151,620	[B]
Unforced Capacity (UCAP) (MW)	138,598	140,061	141,187	[C]
Firm External Support (MW)	3,155	3,155	3,155	[D]
Adjustment to ICAP (MW)	-4,030	-3,958	2,970	[E]
Adjustment to UCAP (MW)	-3,188	-3,135	2,803	[F]
ICAP PRM Requirement (PRMR) (MW)	148,034	149,595	157,745	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	138,565	140,081	147,145	[H]=[C]+[D]+[F]
MISO PRM ICAP	**14.4%**	**14.5%**	**14.2%**	[I]=([G]-[A])/[A]
MISO PRM UCAP	**7.1%**	**7.2%**	**6.6%**	[J]=([H]-[A])/[A]

Table 5.3-1: Future Planning Year MISO System Planning Reserve Margins

Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PRM $_{ICAP}$	14.3%	14.4%	14.5%	14.5%	14.4%	14.4%	14.3%	14.3%	14.2%	14.2%
PRM $_{UCAP}$	7.1%	7.1%	7.2%	7.1%	7.0%	6.9%	6.9%	6.8%	6.7%	6.6%

Table 5.3-2: MISO System Planning Reserve Margins 2015 through 2024

6 Local Resource Zone (LRZ) Analysis – LRR Results

6.1 Planning Year 2015-2016 Local Resource Zone (LRZ) Analysis

MISO calculated the per-unit Local Reliability Requirement (LRR) of Local Resource Zone (LRZ) Peak Demand for years one, two and three (Table 6.1-1 through Table 6.1-3). The unforced capacity (UCAP) values in Table 6.1-1 reflect the unforced capacity within each LRZ and the adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2015-2016 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2015-2016 Planning Resource Auction to determine each LRZ's LRR.

The out year LRZ LRR tables do not include unforced capacity values to maintain the confidential nature of potential EPA related retirements.

PY 2015-2016	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/MS/TX	Formula Key
UCAP (MW)	18,345	14,868	9,195	11,255	7,935	19,158	21,921	10,166	29,195	[A]
Adj. to UCAP (MW) {1d in 10yr}	1,625	-550	1,638	944	2,448	867	2,789	-601	-821	[B]
LRR (UCAP)	19,970	14,318	10,833	12,199	10,383	20,025	24,710	9,565	28,374	[C]=[A]+[B]
Peak Demand (MW)	17,974	12,441	9,527	10,048	8,576	18,067	21,632	7,532	25,512	[D]
Time of Peak Demand	7/14/2015 16:00	7/6/2015 16:00	7/22/2015 19:00	8/11/2015 17:00	8/5/2015 16:00	7/27/2015 16:00	7/27/2015 17:00	7/19/2015 16:00	8/17/2015 16:00	
LRR UCAP P.U. of LRZ Peak Demand	**111.1%**	**115.1%**	**113.7%**	**121.4%**	**121.1%**	**110.8%**	**114.2%**	**127.0%**	**111.2%**	[E]=[C]/[D]

Table 6.1-1: Planning Year 2015-2016 LRZ Local Reliability Requirements

PY 2016-2017	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/MS/TX	Formula Key
LRR (UCAP)	20,261	14,476	10,938	12,199	10,437	20,249	24,859	9,982	28,686	[A]
Peak Demand	18,236	12,582	9,634	10,140	8,672	18,298	21,775	7,972	25,806	[B]
LRR UCAP per-unit of LRZ Peak Demand	111.1%	115.1%	113.5%	120.3%	120.3%	110.7%	114.2%	125.2%	111.2%	[C]=[A]/[B]

Table 6.1-2: Planning Year 2016-2017 LRZ Local Reliability Requirements

PY 2017-2018	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/MS/TX	Formula Key
LRR (UCAP)	20,554	14,554	11,038	12,155	10,315	20,477	25,174	10,101	29,107	[A]
Peak Demand	18,479	12,950	9,727	10,195	8,561	18,506	21,868	8,113	26,193	[B]
LRR UCAP per-unit of LRZ Peak Demand	111.2%	112.4%	113.5%	119.2%	120.5%	110.7%	115.1%	124.5%	111.1%	[C]=[A]/[B]

Table 6.1-3: Planning Year 2017-2018 LRZ Local Reliability Requirements

Appendix A: Load Forecast Uncertainty

A.1 LFU Methodology for Planning Year 2015

Since the North American Electric Reliability Corp. (NERC) load forecasting working group disbanded, MISO adapted the 2011 NERC bandwidth methodology to perform Load Forecast Uncertainty (LFU) analysis and developed regression models similar to NERC. MISO included historical load data (1993-2012) to determine MISO LFU and Local Resource Zone (LRZ) LFU. Starting in the 2014 planning year, MISO South companies were included in the LFU calculation.

Forecasts cannot precisely predict the future. Instead, many forecasts append probabilities to the range of possible outcomes. Each demand projection, for example, represents the midpoint of possible future outcomes. This means that a future year's actual demand has a 50 percent chance of being higher and a 50 percent chance of being lower than the forecast value.

For planning and analytical purposes, it is useful to have an estimate of the midpoint of possible future outcomes, as well as the distribution of probabilities on both sides of that midpoint. Accordingly (similar to NERC), MISO developed upper and lower 80 percent confidence bands. Thus, there is an 80 percent chance of future demand occurring within these bands, a 10 percent chance of future demand occurring below the lower band, and an equal 10 percent chance of future demand occurring above the upper band.

The principal features of the bandwidth methodology include:

1. A univariate time series model in which the projection of demand is modeled as a function of past demand. This approach expresses the current value of the time series as a linear function of the previous value of the series and a random shock. In equation form, the first-order autoregressive model can be written as:

$$y_t = a + y_{t-1} + \varepsilon_t$$

2. The variability observed in demand is used to develop uncertainty bandwidths. Variability, represented by the variance $\sigma\varepsilon$ of the historic data series, is combined with other model information to derive the uncertainty bandwidths.

More details about the NERC methodology can be found at NERC Bandwidth Methodology.

A.1.1 Historical Data Used in the Model

For the 2015-2016 planning year, the LFU methodology did not change from the 2014-2015 planning year. Tables A-1 and A-2 list data sources used for calculation of 2015-2016 LFUs.

<table>
<tr><th colspan="2">North Central Region</th></tr>
<tr><th>Energy Velocity (EV) Data</th><th>MISO Data</th></tr>
<tr><td>All Members currently in MISO: 1993-2008</td><td>All Members Currently in MISO 2009-2012</td></tr>
<tr><td>Duke Indiana: 1993-2011</td><td rowspan="4">Except:
Duke Indiana: 1993-2011
BREC: 2009-11/30/2010
DPC:2009-05/31/2010
MEC, MPW:2009-08/31/2009</td></tr>
<tr><td>BREC: 1993-11/30/2010</td></tr>
<tr><td>DPC:1993-05/31/2010</td></tr>
<tr><td>MEC, MPW:1993-08/31/2009</td></tr>
</table>

Table A-1: MISO North/Central historical load data sources

South Region		
Energy Velocity (EV) Data	**FERC 714- Part III-Schedule 2**	**Directly from LBAs**
Zone 9 members excluding EES and SME: 1993-2012	Entergy EES 1993-1995	Billing data for EAI+AECC served by Entergy 1993-2012
EES 2003-2012 EV New Topology		Billing data for EES 1993-2012
		Entergy EES FERC 714 data 1996-2002
		SME 1993-2012

Table A-2: MISO South historical load data sources

For Energy Velocity (EV) datasets, hourly loads are prepared by Ventyx (Energy Velocity) where the base data source for this dataset is FERC 714 form - Part III of Schedule 2. The raw data filed for FERC 714 form - Part III of Schedule 2 is usually reported at the level of a planning area. However, in some cases, several load serving entities (LSE) file their load data together as a single entity, resulting in less load resolution. Where practical, Ventyx separated filed loads into the smaller load entities that have originally filed load data individually using models developed by Ventyx. Available hourly data was in two categories of New Topology and Old Topology. Old Topology data was available from 1993-2008 at the level of Local Balancing Authority (LBA), LSE, or Municipals where the new topology was available from 2003-2011 at the LBA level.

For each of these topologies, the monthly peaks were derived from the LBA/LSE hourly loads. Based on the correlation between old and new topologies, from six years of overlapping data, the new topology was back casted at a monthly level from 1993 to 2002 for each LBA/LSE. This data, along with the data collected from sources other than EV, were summed to get hourly loads for each of the nine LRZs and MISO to the extent possible. MISO and LRZ monthly peaks were then derived from these hourly loads. Where calculating at an hourly level was not possible, the data was summed at a monthly peak level.

For Entergy, since the FERC 714 data is not broken down by state, or MISO LBA, MISO worked with them to separate the Arkansas portion of the load data from the rest. In order to do that, Entergy provided MISO with hourly billing load data for Arkansas as well as for the overall Entergy system. Since the assumptions in this data were different from FERC 714 actual loads, Entergy and MISO agreed to use the billing data to find the hourly ratio of Arkansas load and apply that to the Entergy FERC 714 submission to get the appropriate portions. This was agreed to be the best way available to us to split the zone 8 portion of Entergy system from the rest.

MISO collected LBA-level load data to be consistent with 2014 MISO footprint, the list of LBAs is provided in Table A.1-3. This table provides acronyms for LBAs.

No.	Local Balancing Area	Acronym	Zone
1	Dairyland Power Cooperative	DPC	LRZ-1
2	Great River Energy	GRE	LRZ-1
3	Minnesota Power	MP	LRZ-1
4	Montana-Dakota Utilities Co.	MDU	LRZ-1
5	Northern States Power Co. (Xcel)	NSP/XEL	LRZ-1
6	Otter Tail Power Co.	OTP	LRZ-1
7	Southern MN Municipal Power Agency	SMP	LRZ-1
8	Alliant East - Wisconsin Power and Light Co.	ALTE	LRZ-2
9	Madison Gas and Electric Co.	MGE	LRZ-2
10	Upper Peninsula Power Co.	UPPC	LRZ-2
11	Wisconsin Electric Power Co.	WEC	LRZ-2
12	Wisconsin Public Service Corp.	WPS	LRZ-2
13	Alliant West - Interstate Power & Light	ALTW	LRZ-3
14	MidAmerican Energy Co.	MEC	LRZ-3
15	Muscatine Power & Water	MPW	LRZ-3
16	Ameren Illinois	AMIL	LRZ-4
17	Southern Illinois Power Cooperative	SIPC	LRZ-4
18	Springfield Illinois - City Water Light & Power	CWLP	LRZ-4
19	Ameren Missouri	AMMO	LRZ-5
20	Columbia Missouri Water and Light Department	CWLD	LRZ-5
21	Big Rivers Electric Corp.	BREC	LRZ-6

22	Duke Energy Indiana	DUK(IN)	LRZ-6
23	Hoosier Energy Rural Elec.	HE	LRZ-6
24	Indianapolis Power & Light	IPL	LRZ-6
25	Northern Indiana Public Service	NIPSCO	LRZ-6
26	Southern Indiana Gas & Electric	SIGE	LRZ-6
27	Consumers Energy – METC	CONS	LRZ-7
28	Detroit Edison Co.	DECO	LRZ-7
29	Entergy Arkansas	EAI	LRZ-8
30	Central Louisiana Electric Co. Inc.	CLECO	LRZ-9
31	Entergy Services, Inc.	EES	LRZ-9
32	Lafayette (City of)	LAFA	LRZ-9
33	Louisiana Energy and Power Authority	LEPA	LRZ-9
34	Louisiana Generating/Cajun Electric	LAGN	LRZ-9
35	South Mississippi Electric Power Association	SME	LRZ-9

Table A.1-3: List of Local Balancing Authorities (LBA)

A.2 MISO LFU results

Using the methodology discussed in Section A.1 and the data set explained in Section A.1.1, the MISO LFU for the planning year 2015 is 3.8 percent. MISO developed an auto-regression model for each LRZ and the LFU results are displayed in Table A.2-1. The definitions of the nine LRZs are indicated in Table A.1-3.

Zones	LFU
LRZ 1	2.8%
LRZ 2	4.5%
LRZ 3	2.9%
LRZ 4	4.5%
LRZ 5	4.2%
LRZ 6	3.3%
LRZ 7	5.2%
LRZ 8	4.9%
LRZ 9	3.1%

Table A.2-1: Zonal LFU results

Appendix B: Comparison of Planning Year 2014 to 2015

To compute changes in the Planning Reserve Margin (PRM) target on an Unforced Capacity (UCAP) basis, from the 2014-2015 planning year to the 2015-2016 planning year, multiple study sensitivity analyses were performed. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. The impact of the incremental PRM changes from 2014 to 2015 are shown in the waterfall chart of Figure B-1 and explained in section B.1 as well.

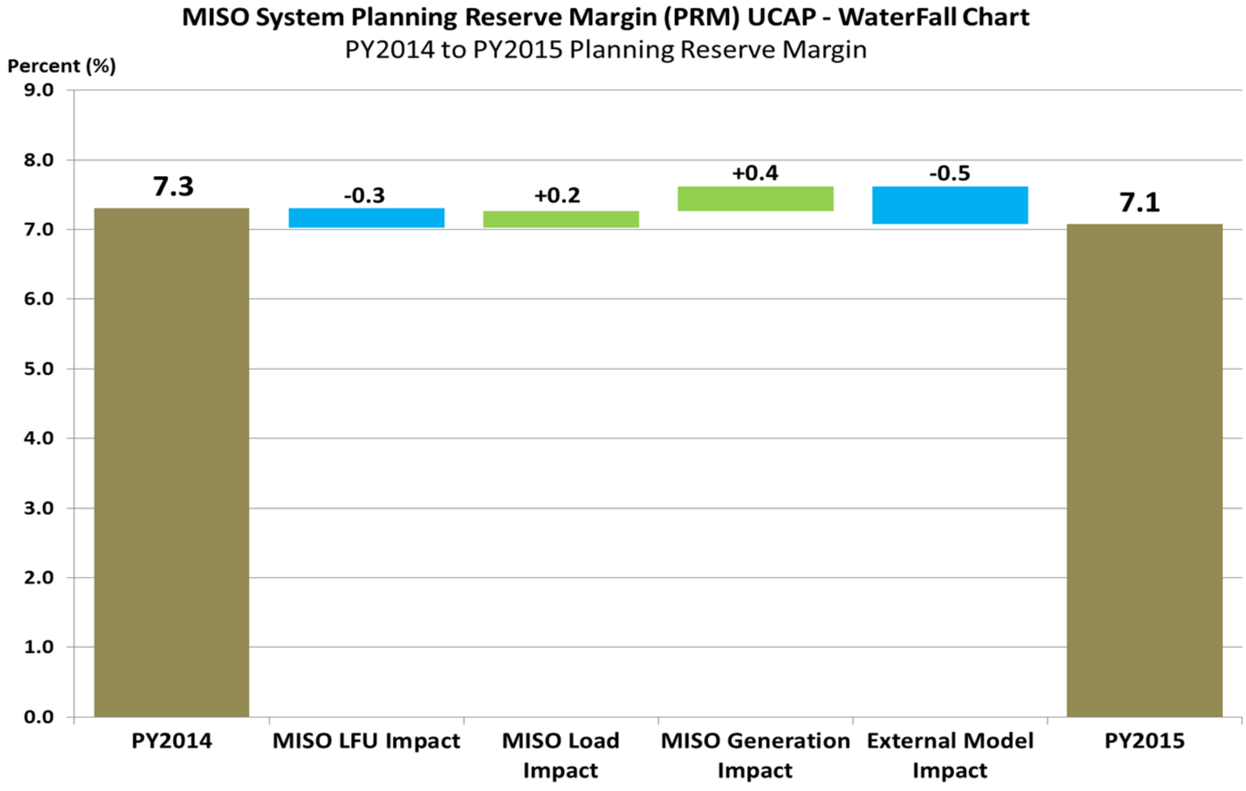


Figure B-1: Waterfall chart of 2014 PRM UCAP to 2015 PRM UCAP

B.1. Waterfall Chart Details

B.1.1 MISO LFU

The MISO aggregate LFU value for Planning Year 2015-2016 decreased 0.1 percent from the 2014-2015 value, which resulted in an overall decrease to the MISO PRM UCAP of 0.3 percent. Eight of the nine Local Resource Zone LFU values decreased, which drove the overall MISO aggregate LFU value to decrease.

B.1.2 Internal Load

For the 2015-2016 planning year, the MISO Coincident Peak Demand increased by 1.7 percent from the 2014-2015 planning year, which was driven by actual load forecasts submitted for Local Resource Zones 8 and 9. In the 2014 LOLE Study, vendor data was used for MISO South, which was significantly lower than the demand forecasts submitted by MISO South Load Serving Entities (LSE) in November 2013. These updated forecasts in combination with the number of days the LOLE model experienced demands greater than 0.95 per unit of Peak Demand (8 in 2014 LOLE study to 12 in 2015 LOLE study) resulted in a 0.2 percent increase in PRM UCAP.

B.1.3 Internal Generation

The 2015-2016 planning year LOLE study utilized the 2014 Planning Resource Auction converted capacity as a starting point for which resources to include in the study. This was to better align the LOLE study with the Planning Resource Auction to ensure that only resources eligible as a Planning Resource were included. An exception was made for resources in MISO's March 2014 Commercial Model that weren't part of the 2014 PRA, but stated in the 2015 OMS-MISO Survey that they would be available in 2015. These resources were also included. All internal Planning Resources were modeled in the Local Resource Zone in which they are physically located.

Behind-the-meter generation was explicitly modeled as a thermal generator with a monthly capacity and forced outage rate, which was a change from the 2014 LOLE study where behind-the-meter generation was modeled as an energy-limited resource.

Lastly, the overall MISO Equivalent Forced Outage Rate Demand (EFORd) increased 0.4 percent. This coupled with the two changes above resulted in an overall increase to the MISO PRM UCAP of 0.4 percent.

B.1.4 External Support

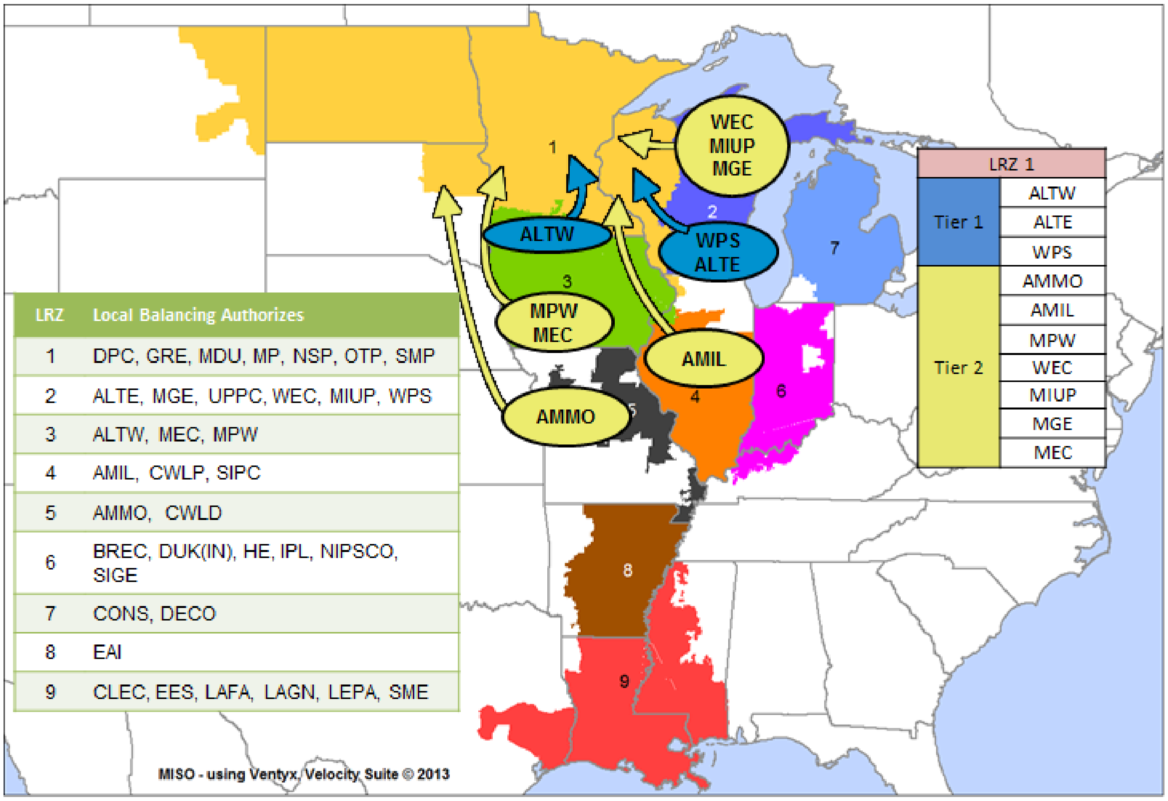
Firm external support increased by 52 MW from the 2014 LOLE study to the 2015 LOLE study. This amount was taken from the 2014 Planning Resource Auction, which totaled 3,155 MW of firm external resources that either submitted a Fixed Resource Adequacy Plan or cleared in the auction.

Additionally, the target PRM for PJM was set based on the reserve margin cleared in the Reliability Pricing Model. This margin is higher than PJM's Planning Reserve Margin calculated in their Reserve Requirement Study (RRS), which is similar to MISO LOLE Study. This was used as PJM's PRM target in the 2014 LOLE Study. This was an improvement from last year as capacity cleared in PJM"s RPM has capacity obligations for the planning year in which it clears.

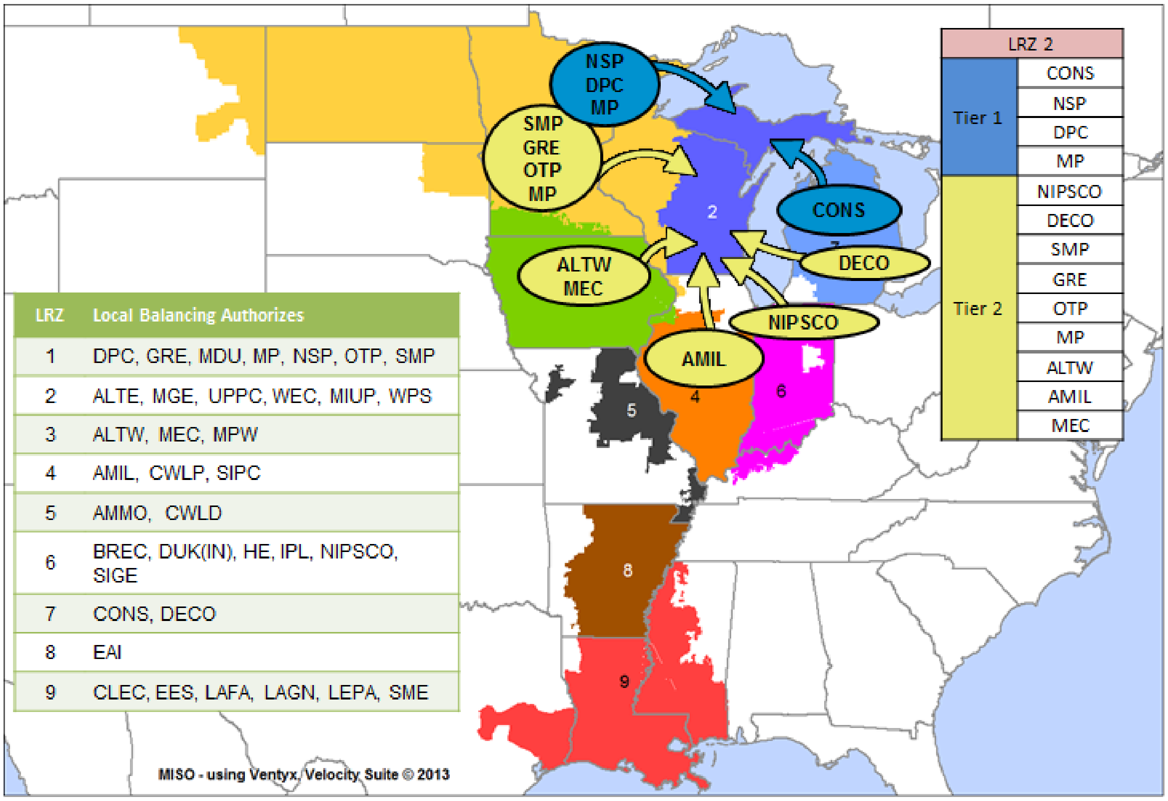
Non-firm external support also increased due to updated external modeling data and a higher PRM target used for PJM. This amounted to an additional 431 MW of non-firm external support as compared to the 2014 LOLE study. The total non-firm support seen in the 2015 LOLE study was approximately 2,300 MW.

Appendix C: Transfer Analysis

C.1: Tier Maps

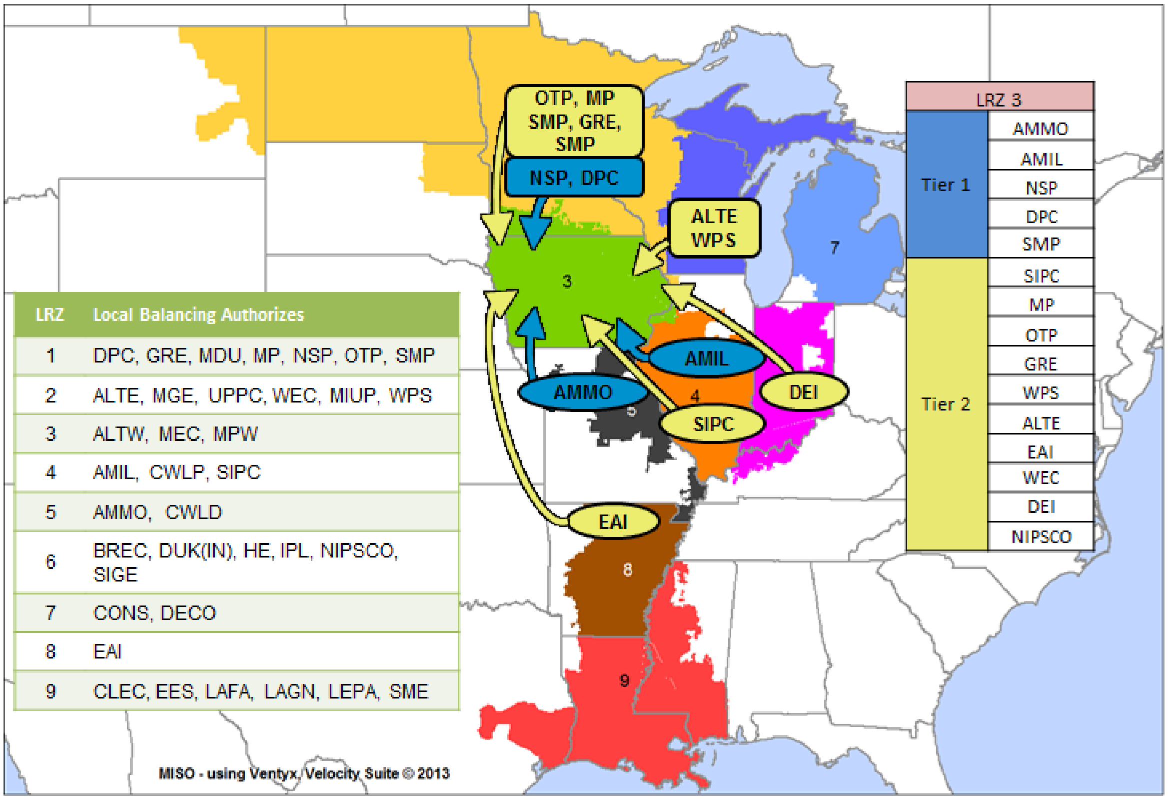


Zone 1: DPC, GRE, MDU, MP, OTP, SMMPA, XEL

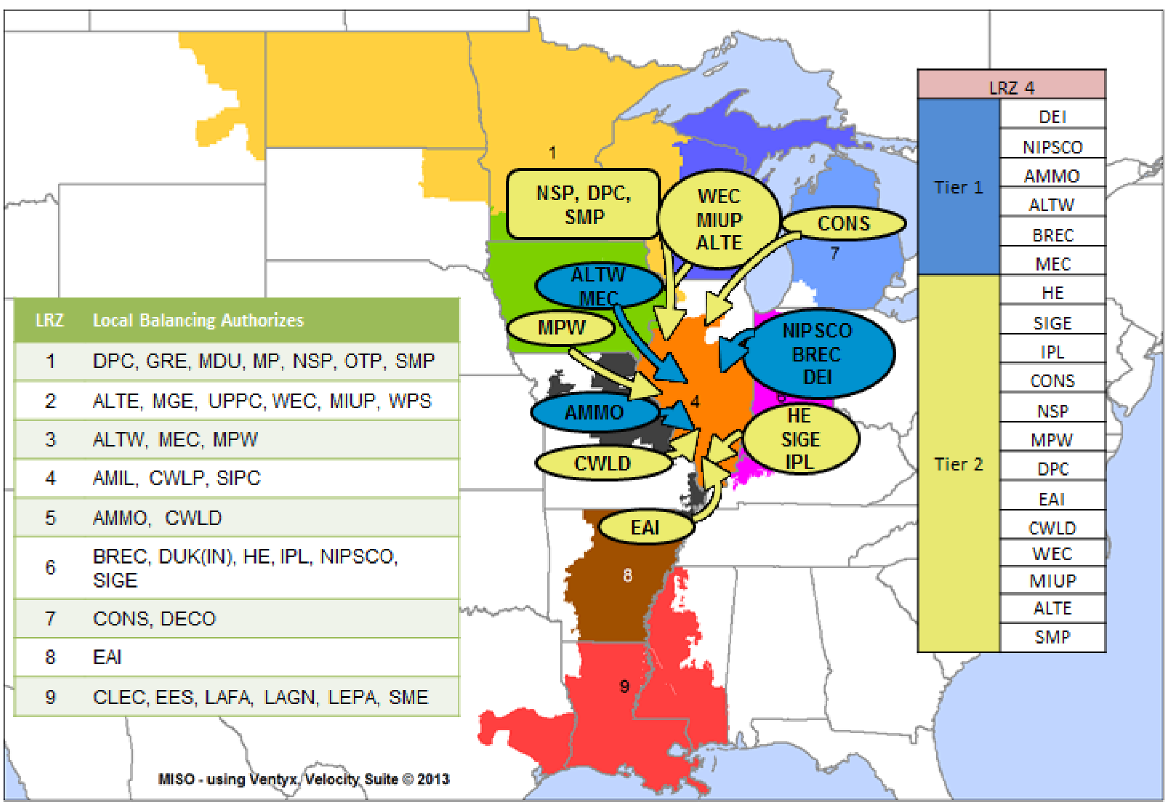


Zone 2: ALTE, MGE, UPPC, WEC, MIUP, WPS

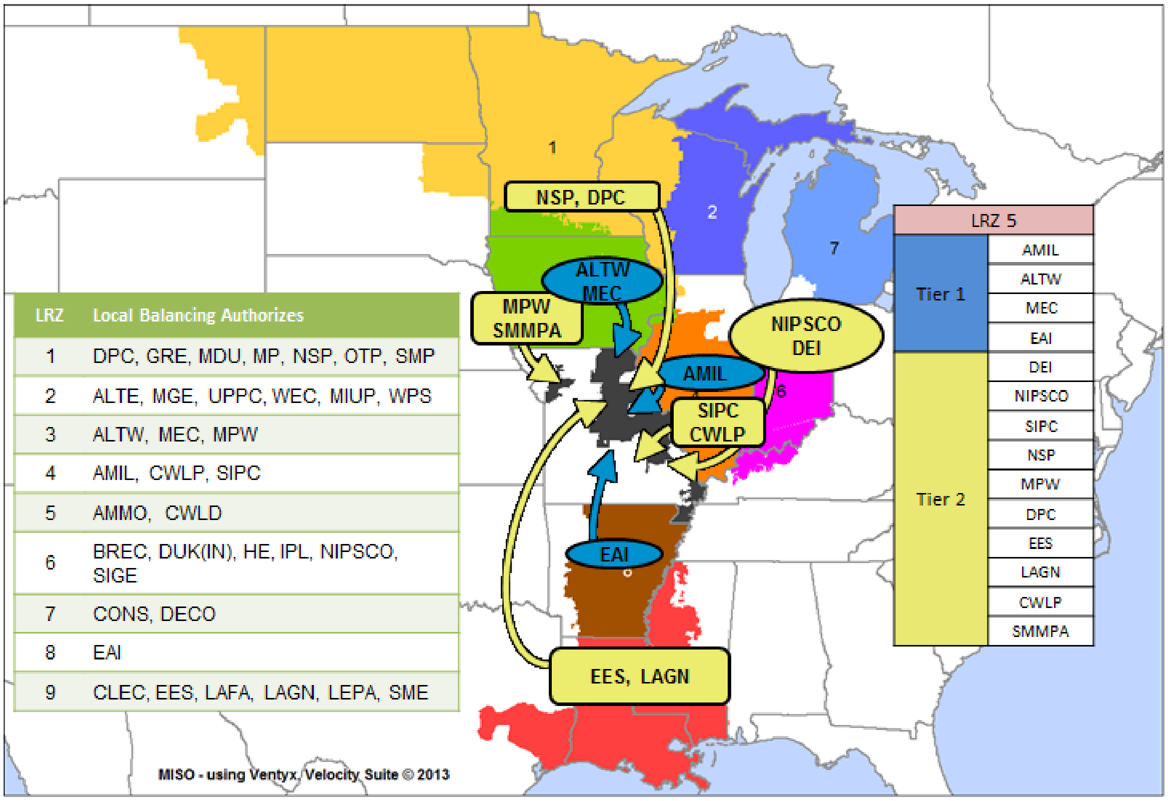
Note: MIUP LBA split from WEC expected to be in-place prior to Planning Year 2015-16



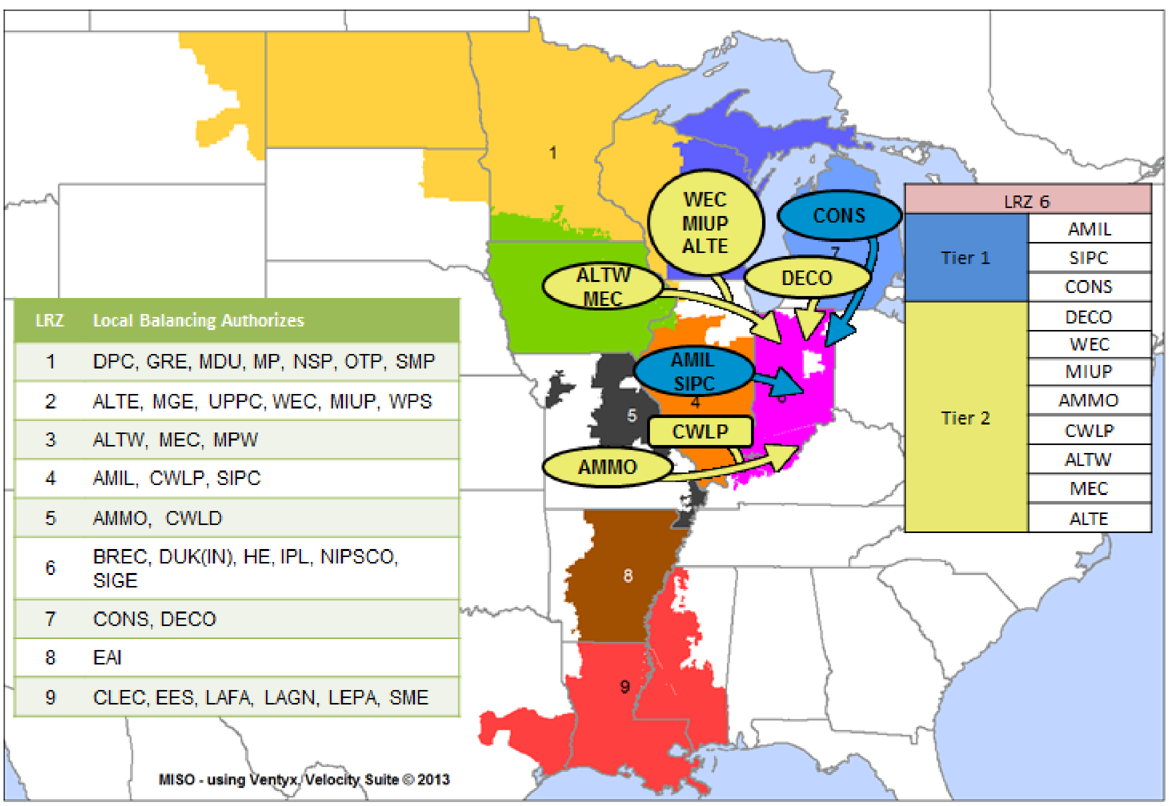
Zone 3: ALTW, MEC, MPW



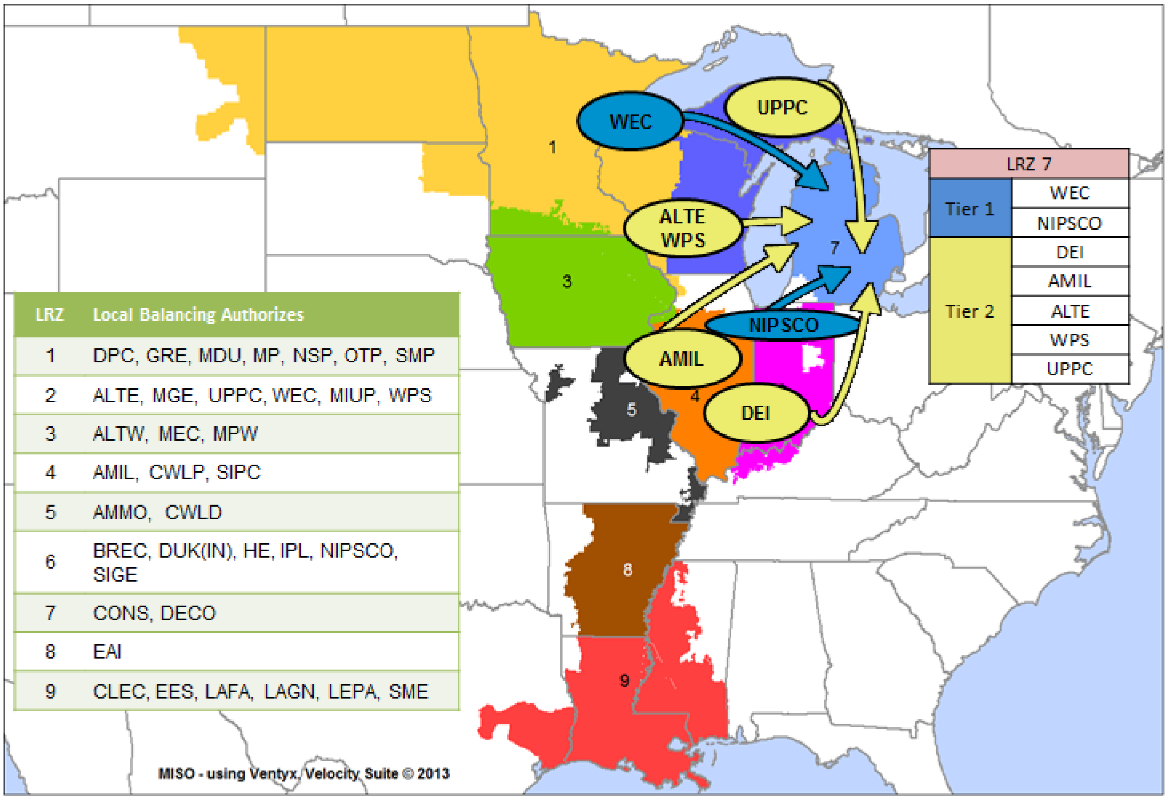
Zone 4: AMIL, CWLP, SIPC



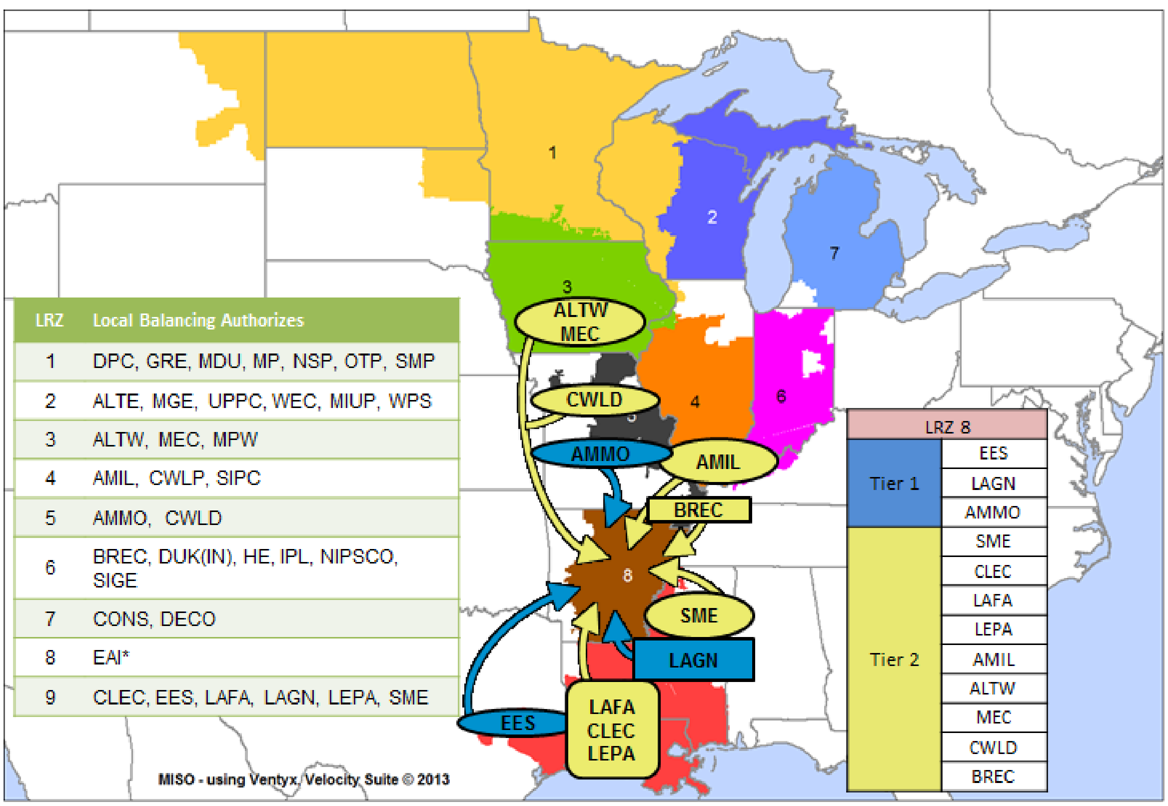
Zone 5: AMMO, CWLD



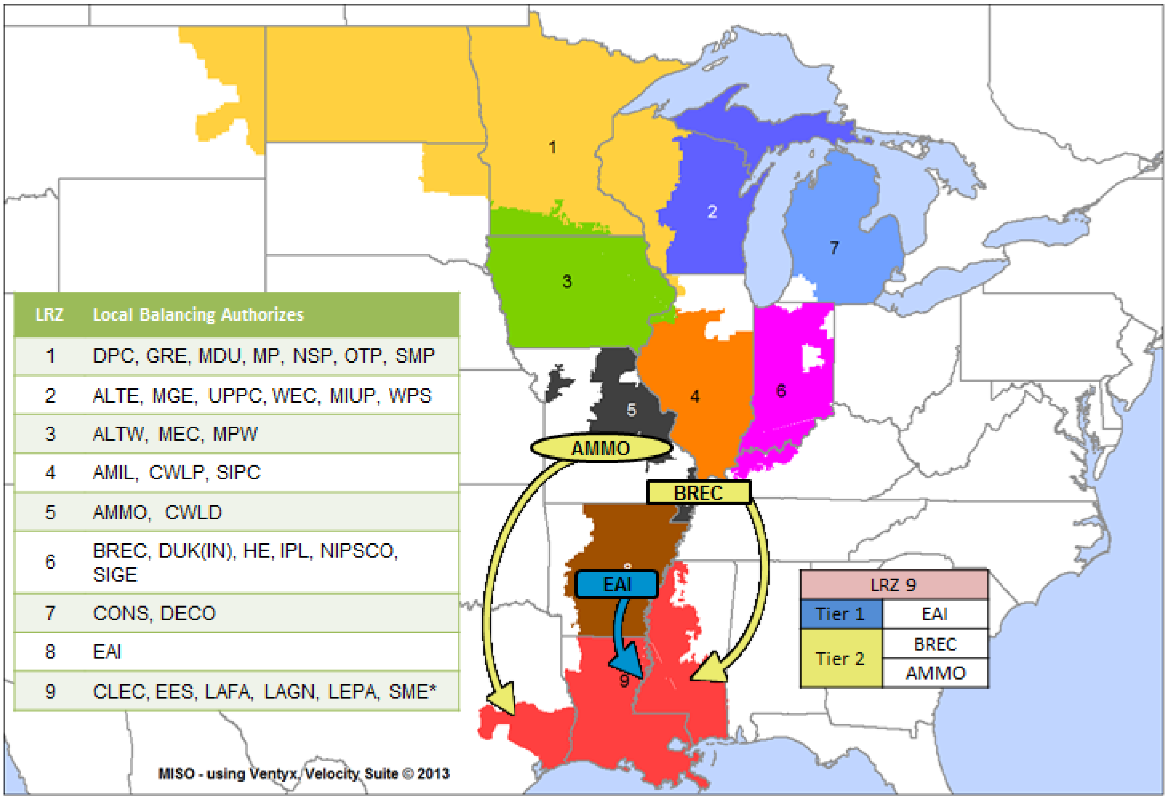
Zone 6: BREC, DEM, HE, IPL, NIPS, SIGE



Zone 7: ITC, MECS



Zone 8: EAI (PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR now modeled in EAI LBA)



Zone 9: CLEC, EES, LAFA, LEPA, SME, and LAGN
Note: BRAZ, DERS, EES-EMI and BCA now modeled in EES power flow area

C.2: Planning Year 2015-16 Detailed CIL Results

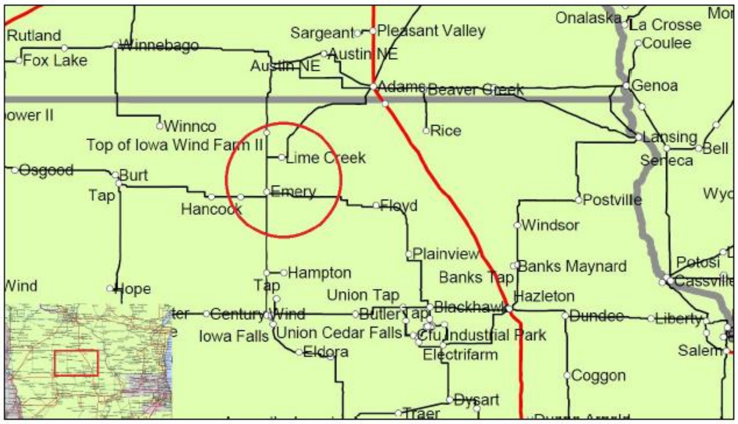
Zone 1 – MN and ND

Initial limit 3,376 MW

- Constraint: Worth County to Colby 161 kV
- Contingency: Barton to Adams 161 kV

Redispatched Limit 3,735 MW

- Redispatched 2,000 MW of generation in MEC, ITCM, XEL, and GRE



Zone 2 – WI and MI

Initial limit 2,104 MW

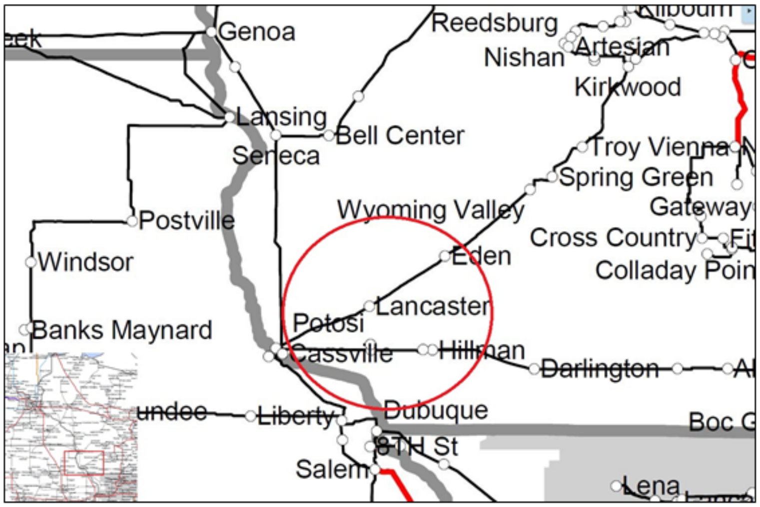
- Constraint: Turkey River – Stoneman 161kV
- Contingency: AT5/7 TRANSFORMER FAULT

Redispatched Limit 2,903 MW

- Redispatched 694 MW in WEC, ALTE, MGE, & ALTW

Multiple operating scenarios during Planning Year due to upgrade to Lore – Turkey River – Stoneman 161kV

- Most limiting timeframe is after line upgrade and unit retirement
- Import limit set to expected value seen during summer period after considering outage could end early
- Limit after upgrade and retirement in a summer scenario is much less (approximately 1,000 MW total limit after redispatch)



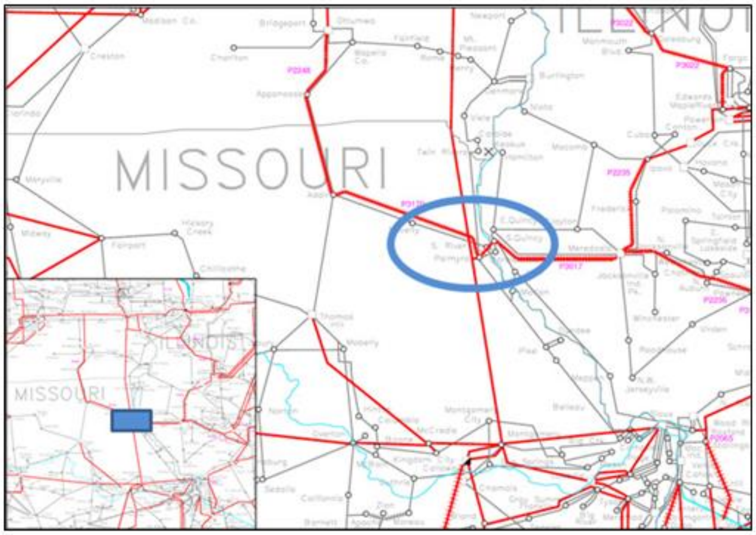
Zone 3 – IA & MN

Initial limit 726 MW

- Constraint: Palmyra Transformer
- Contingency: Louisa to Sub T to Hills

Redispatched Limit 1,972 MW

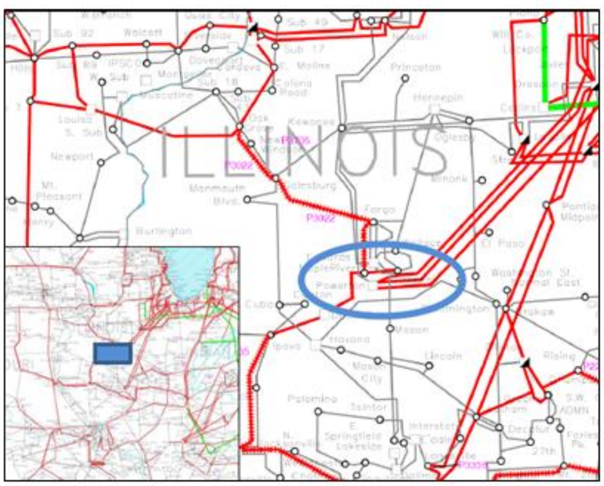
- Redispatched 2,000 MW of generation in XEL, ALTW, & MEC

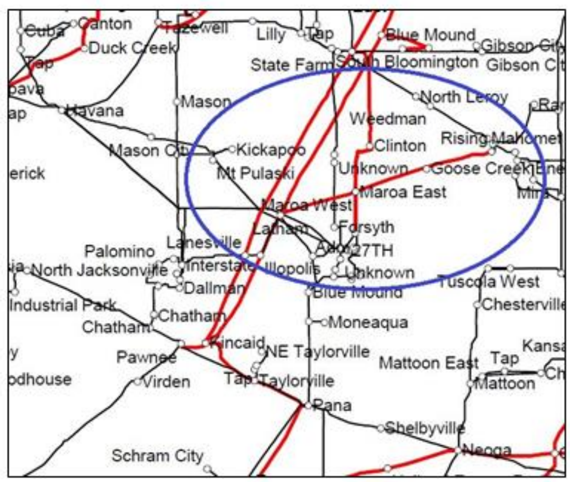


Zone 4 – IL

Initial limit 850 MW	• Monitored Element: Tazewell 138/345 kV Xfr 1 • Contingent Element: Tazewell 138/345 kV Xfr 2 • Redispatched 2,000 MW in MISO & PJM (RCF)
Intermediate Constraint	• Monitored Element: Palmyra 161/345 kV Xfr • Contingent Element: Spencer to Montgomery 345 kV • Redispatched 2,000 MW in NIPS, BREC, AMMO, AMIL, ITCM, MEC
Current limit 3,130 MW	• Monitored Element: Rising 345/138 kV Xfr • Contingent Element: Maroa E to Clinton 345 kV, Maroa E to Oreana E 345 kV, Maroa E to Goose Creek 345 kV

Zone 4 – IL





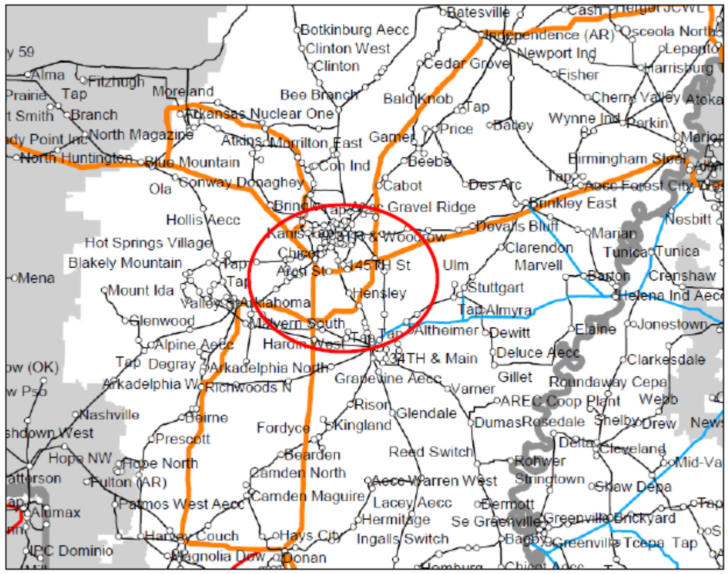
Zone 5 – MO

Initial limit 3,899 MW

- Constraint: White Bluff to Keo 500 kV
- Contingency: Sheridan to Mabelvale 500 kV

Current Limit 3,899 MW

- Redispatch results in a more limiting constraint



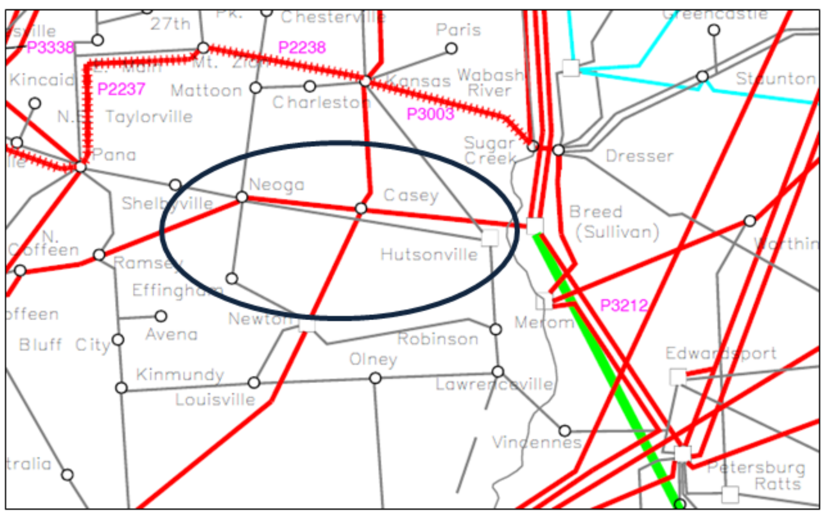
Zone 6 – IN & KY

Initial limit 5,090 MW

- Constraint: Newton to Casey 345 kV
- Contingency: Casey to Neoga 345 kV

Redispatched limit 5,649 MW

- Constraint: Neoga to Holland 345 kV
- Contingency: Xenia to Mount Vernon 345 kV
- Redispatched 2,000 MW of generation in METC & AMIL



Zone 7 – MI

Initial limit 2,412 MW

- Monitored Element: Battle Creek to Argenta 345 kV
- Contingent Element: Argenta to Tompkins 345 kV
- Redispatched 2,000 MW in WEC & METC

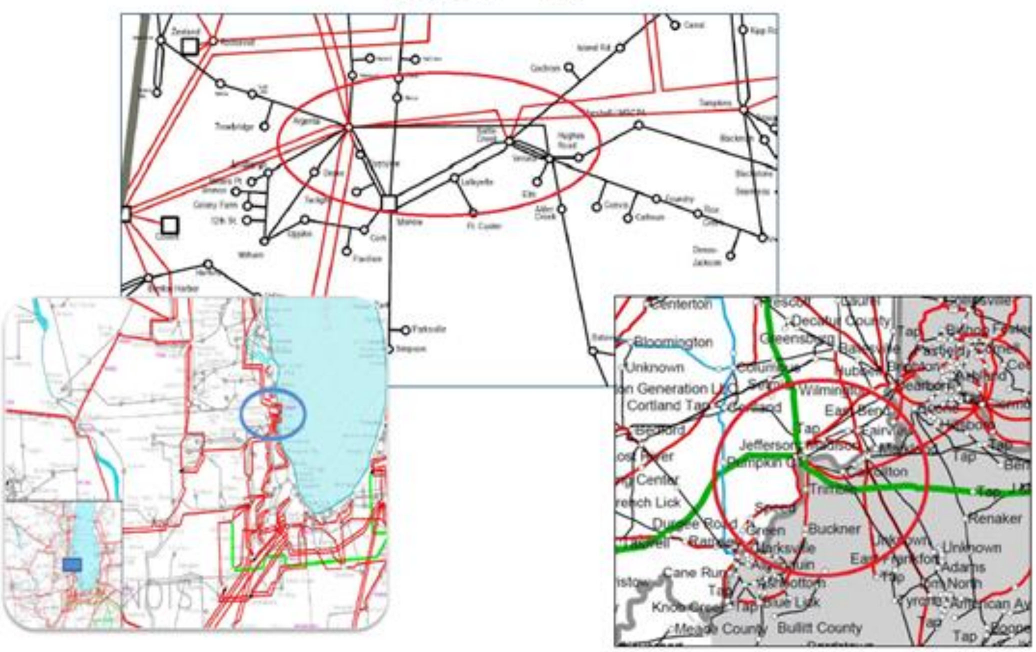
Intermediate constraint

- Monitored Element: Zion EC to Zion Station 345 kV
- Contingent Element: Zion to Pleasant Prairie 345 kV
- Redispatched 2,000 MW in ALTE, METC, & WEC

Current limit 3,813 MW

- Monitored Element: Clifty Creek to Trimble County 345 kV
- Contingent Element: Rockport to Jefferson 765 kV

Zone 7 – MI



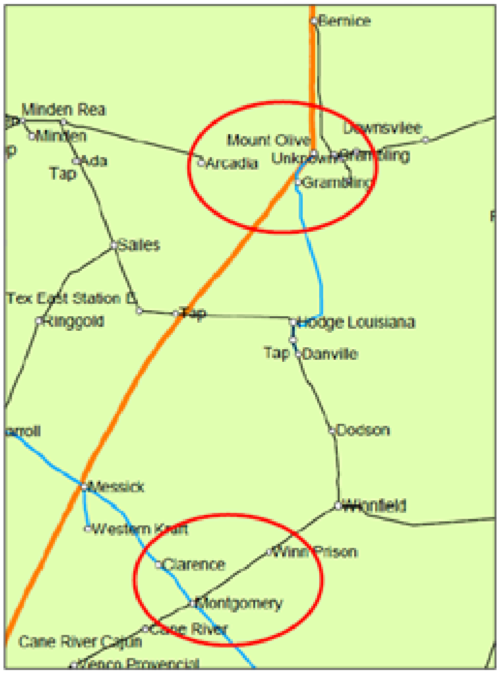
Zone 8 – AR

Initial limit 482 MW

- Constraint: Montgomery to Clarence 230 kV
- Contingency: Montgomery to Winnfield 230 kV

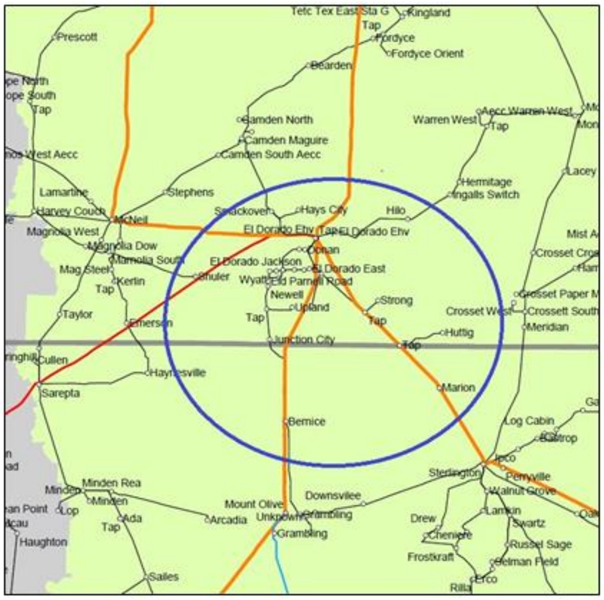
Redispatched limit 2,074 MW

- Constraint: Mt Olive – Vienna 115 kV
- Contingency: Mt Olive – El Dorado 500 kV
- Redispatched 2,000 MW of generation in EES, AMMO, & CLECO



Zone 9 – TX, LA, MS

- **Current Limit: 3,320 MW**
  - Constraint: Junction City to Bernice 115 kV
  - Contingency: Mount Olive to El Dorado 500 kV
- **Current Limit: 3,320 MW**
  - Redispatch results in a more severe limiter



C.3: Planning Year 2015-16 Detailed CEL Results

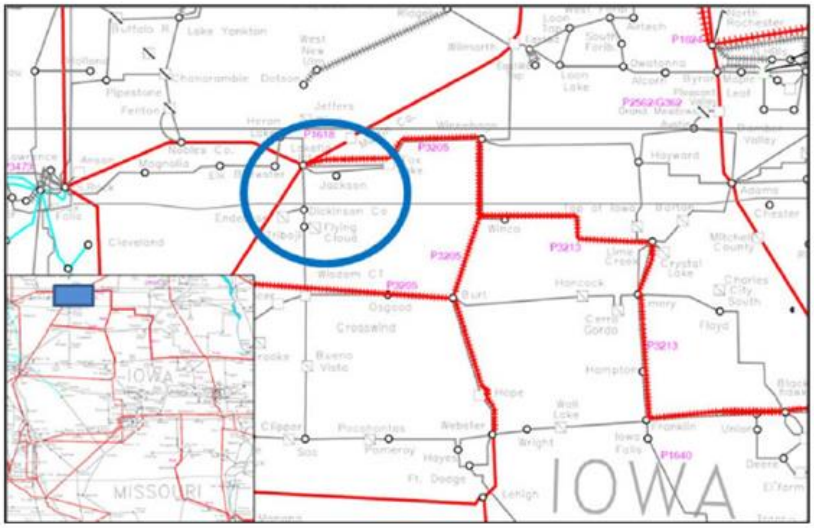
Zone 1 – MN and ND

Initial limit 604 MW

- Constraint: Lakefield to Dickinson County 161 kV
- Contingency: Webster to Lehigh 345/161 kV Transformer

Redispatched Limit 604 MW

- Redispatch results in a more severe limiter



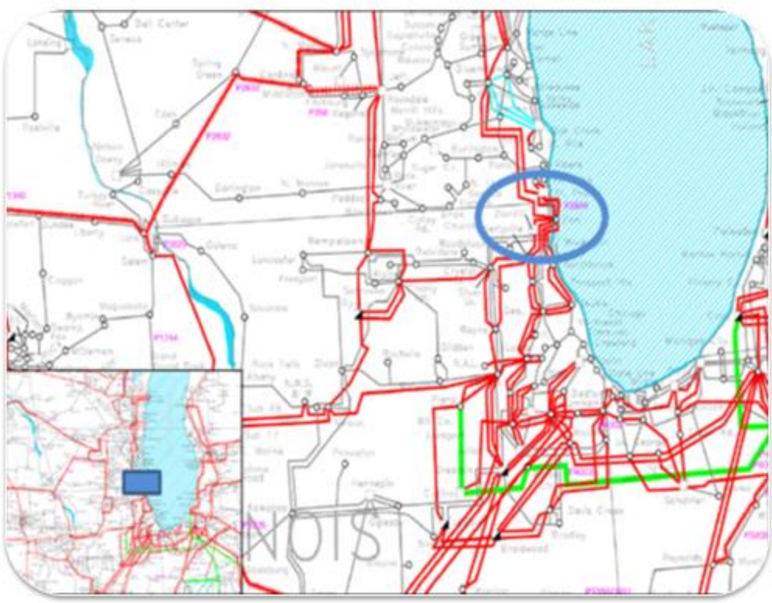
Zone 2 – WI and MI

Initial limit 1,167 MW

- Constraint: Zion Station to Zion Energy Center
- Contingency: Zion Station to Pleasant Prairie

Redispatched Limit 1,516 MW

- Redispatched 1,188 MW of generation in WEC, MGE, ALTE & CE



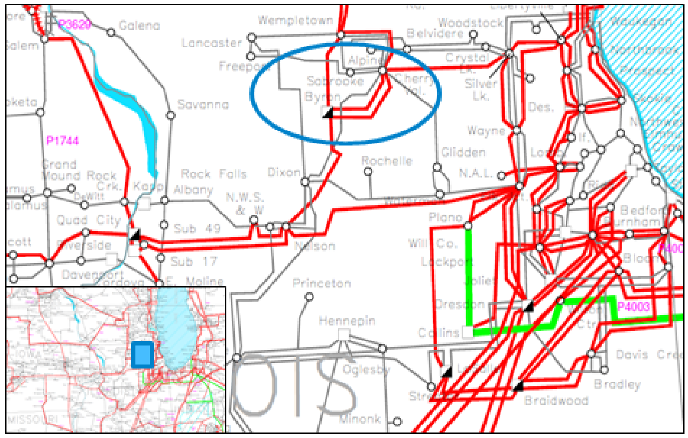
Zone 3 – IA & MN

Initial limit 648 MW

- Constraint: Byron to Cherry Valley 345 kV Red Circuit
- Contingency: Byron to Cherry Valley 345 kV Blue Circuit

Redispatched Limit 1,477 MW

- Redispatched 1,610 MW of generation in MEC, NIPS, & WEC



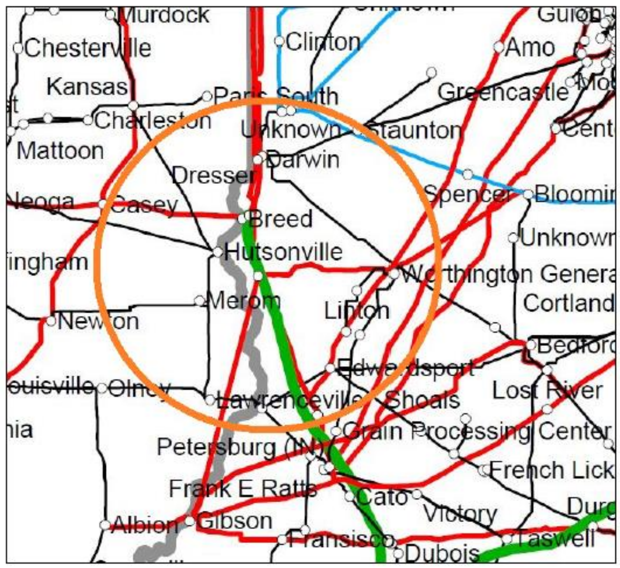
Zone 4 – IL

Initial limit 4,125 MW

- Constraint: Hutsonville to Robinson Marathon North Tap 138 kV
- Contingency: Newton to Robinson Marathon 138 kV

Redispatched Limit 4,125 MW

- No redispatch available



Zone 5 – MO

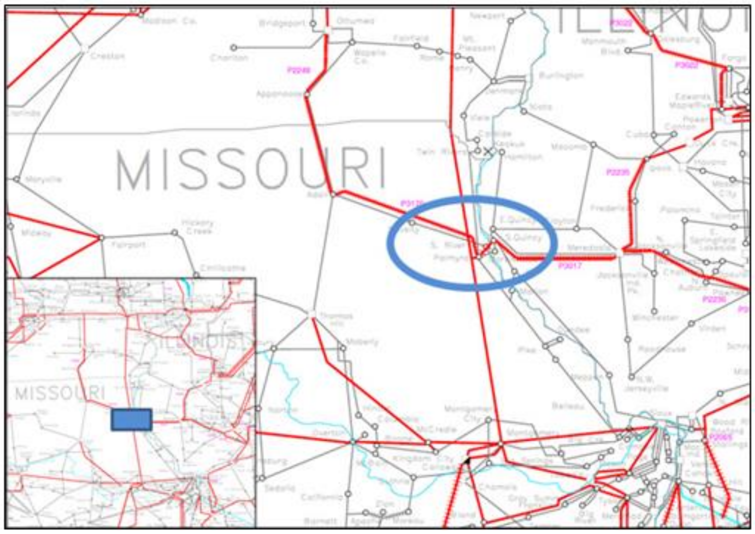
Initial limit 0 MW

- Constraint: Palmyra Transformer
- Contingency: Louisa to Sub T to Hills

Redispatched Limit 0 MW

- Constraint: Palmyra Transformer
- Contingency: Louisa to Sub T to Hills

Modeling update analyzed after September 10 meeting modified zone 5 base interchange and available generation capacity. Model update included modeling of AMMO resources in their physical location (Illinois) to align with PRM calculation. Transfer is initially limited by constraint listed above, then is limited by generation.



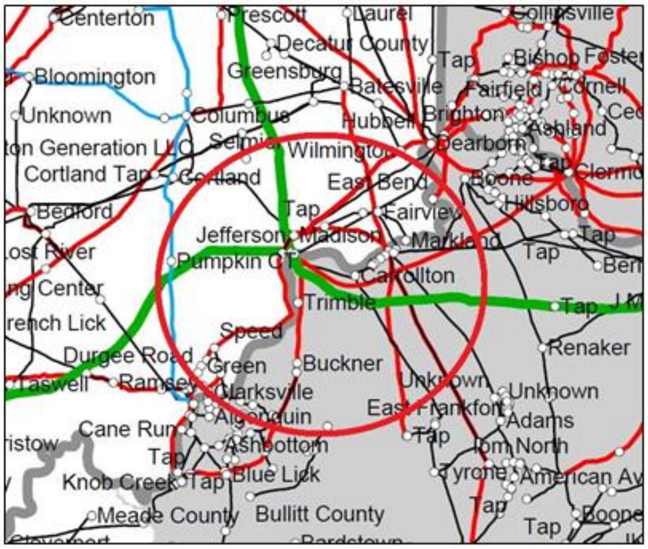
Zone 6 – IN & KY

Initial limit 2,930 MW

- Constraint: Clifty Creek to Trimble 345 kV
- Contingency: Rockport to Jefferson 765 kV

Current Limit 2,930 MW

- No redispatch available



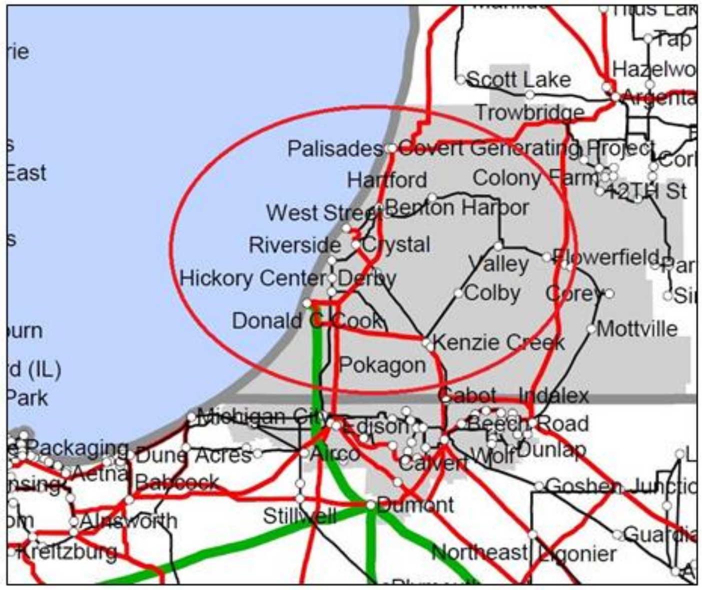
Zone 7 – MI

Initial limit 4,799 MW

- Constraint: Benton Harbor 138/345 kV Transformer
- Contingency: Benton Harbor to Cook 345 kV

Redispatched Limit 4,804

- Redispatched 53 MW in METC and ITCT



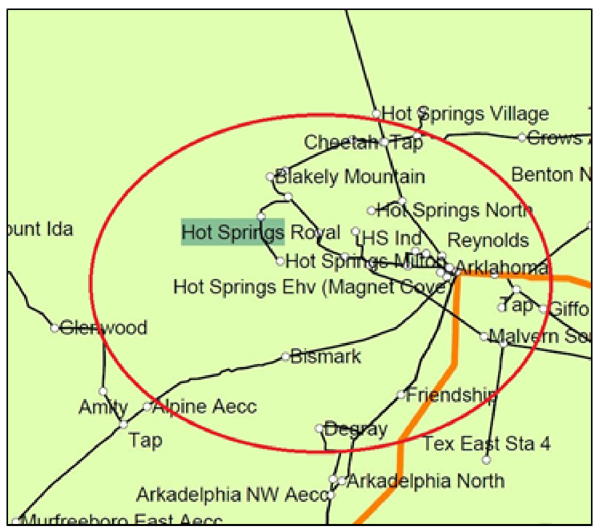
Zone 8 – AR

Initial limit 2,767 MW

- Constraint: Hot Springs East to Butterfield 115 kV
- Contingency: Sheridan to Magnet Cove 500 kV

Redispatched limit 3,022 MW

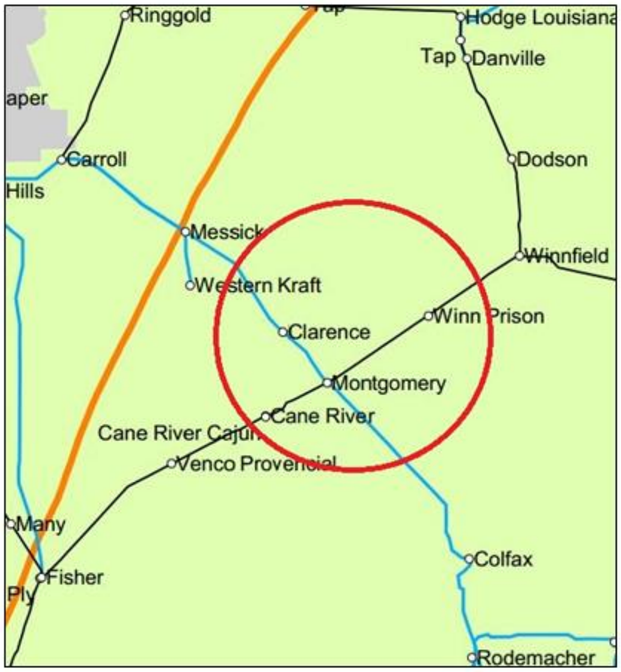
- Constraint: Woodward to Stuttgart Ricuskey 230 kV
- Contingency: Keo to West Memphis 500 kV
- Redispatched 2,000 MW in EES-EAI



Zone 9 – TX, LA, MS

- **Initial Limit 951 MW**
  - Constraint: Montgomery to Clarence 230 kV
  - Contingency: Montgomery to Winnfield 230 kV

- **Redispatched limit 3,239 MW**
  - Constraint: White Bluff to Keo 500 kV
  - Contingency: Sheridan to Mabelvale 500 kV
  - Redispatched 2,000 MW of generation in EES & CLEC



C.4: 2016-17 Detailed CIL Results

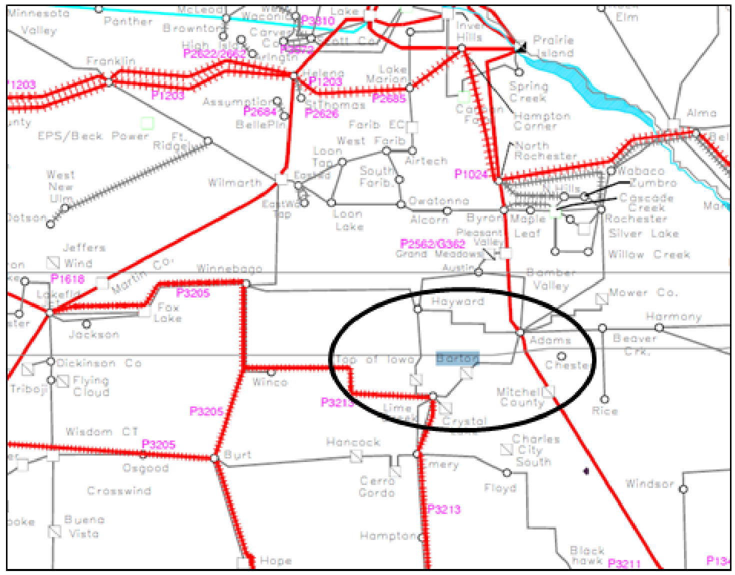
Zone 1 – MN and ND

Initial limit 3,430 MW

- Constraint: Worth County to Colby 161 kV Line
- Contingency: Barton to Adams 161 kV line

Re-dispatched Limit 3,453 MW

- Generation re-dispatched in MEC, ITCM, XEL, and GRE.
- Total re-dispatch of 2,000 MW



Zone 2 – WI and MI

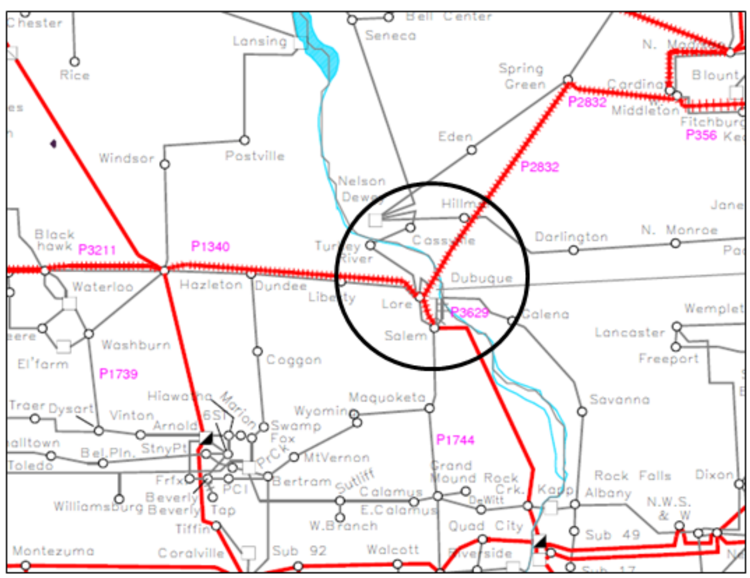
Initial limit 1,362 MW

- Constraint: Turkey River – Stoneman 161kV
- Contingency: Seneca – Genoa 161kV

Re-dispatched Limit 3,586 MW

- Re-dispatch 2,000 MW in ITCM, ALTE, ALTW, MGE, MEC,

Note: Lore – Turkey River – Stoneman 161 kV upgrade in-service and unit retired.



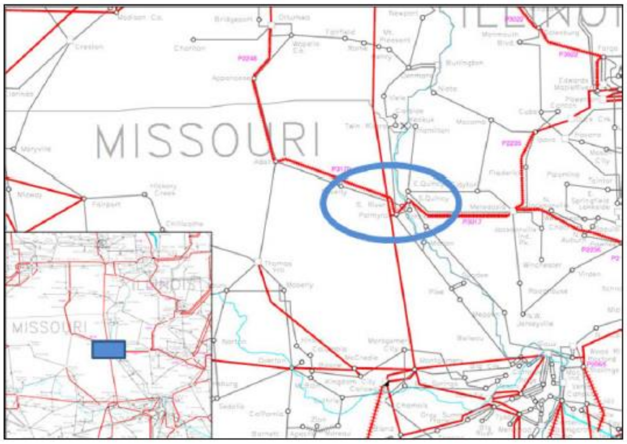
Zone 3 – IA & MN

Initial limit 787 MW

- Constraint: Palmyra Transformer
- Contingency: Louisa to Sub T to Hills

Re-dispatched Limit 3,711 MW

- Re-dispatch in XEL, ALTW, AMIL, AMMO, & MEC
- Total re-dispatch of 2,000MW



Zone 4 – IL

Initial limit 675 MW

- Monitored Element: Palmyra Transformer
- Contingent Element: Montgomery to Spencer
- Re-dispatched 2,000 MW

Intermediate Constraint

- Monitored Element: Oak Grove to Mercer
- Contingent Element: Electric Junction to Nelson 345kV
- Re-dispatched 2,000 MW

Current limit 1,931 MW

- Monitored Element: West Point to Lafayette 230kV
- Contingent Element: Eugene to Caysub 345kV

Zone 4 – IL

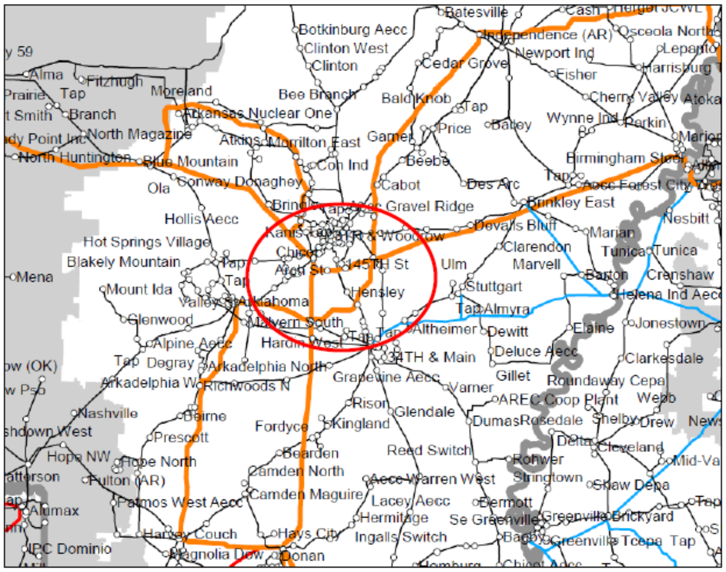
Zone 5 – MO

Initial limit 3,131 MW

- Constraint: White Bluff to Keo 500 kV Line
- Contingency: Sheridan to Mabelvale 500 kV Line

Re-dispatched Limit 3,991 MW

- Re-dispatched generation in EAI, AMIL, & AMMO
- Re-dispatch generation total is 2,000 MW



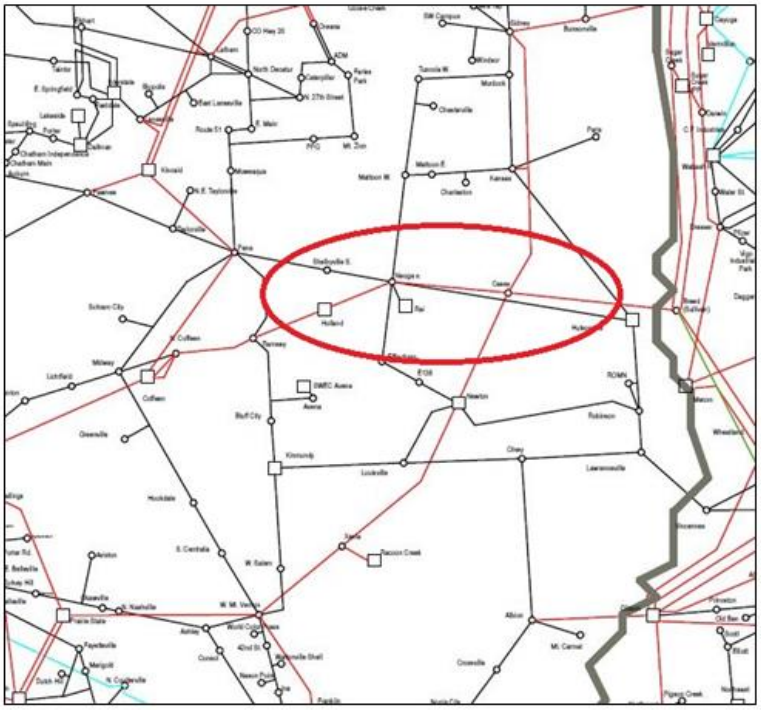
Zone 6 – IN & KY

Initial limit 4,497 MW

- Constraint: Newton To Casey 345 kV Line
- Contingency: Casey To Neoga 345 kV Line

Re-dispatched limit 5,389 MW

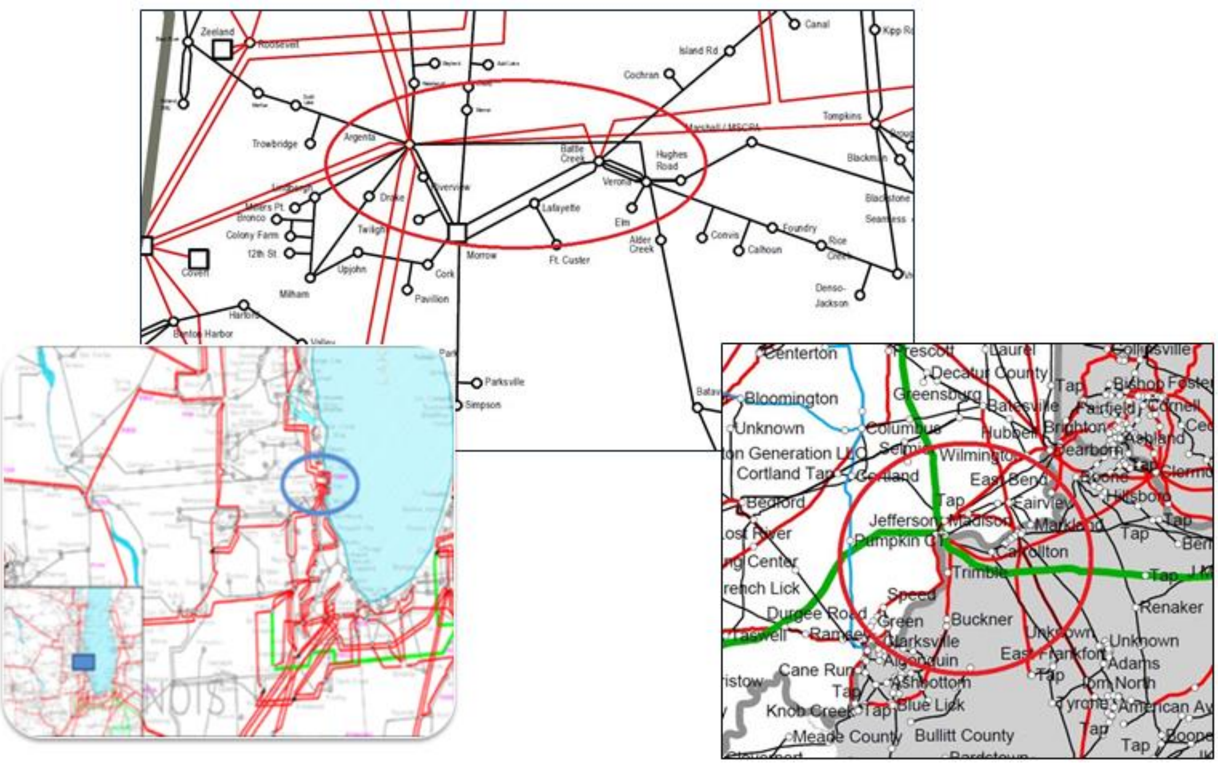
- Re-dispatch applied 2,000 MW of generation
- Re-dispatched generation in METC & AMIL



Zone 7 – MI

Initial limit 2,920 MW	• Monitored Element: Zion EC to Zion Station 345kV • Contingent Element: Zion to Pleasant Prairie 345kV • Re-dispatch 2,000 MW in CE, NIPS, DEI, WEC
Intermediate constraint	• Monitored Element: Trimble County to Clifty Creek 345kV • Contingent Element: Rockport to Jefferson 345kV • Re-dispatched 2,000 MW in EES, ALTE, AMIL, WEC, DEI
Current limit 3,666 MW	• Monitored Element: Battle Creek to Argenta 345kV • Contingent Element: Argenta to Tompkins 345kV

Zone 7 – MI



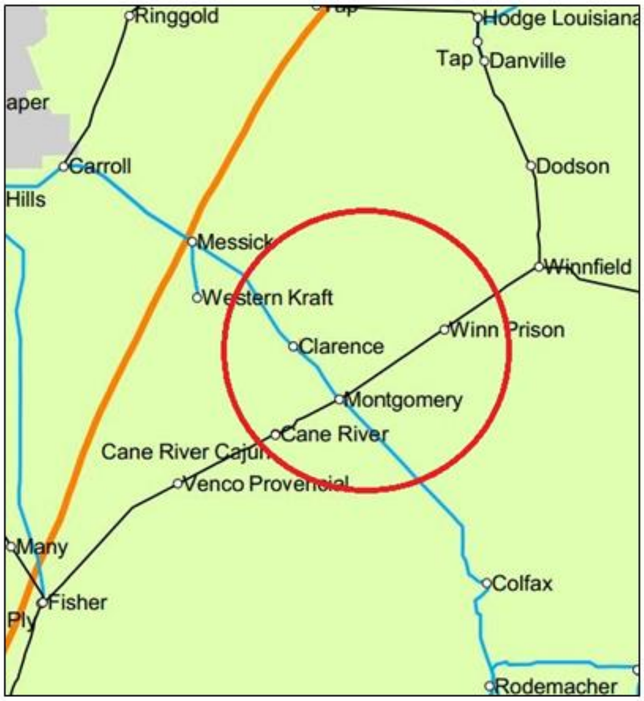
Zone 8 – AR

Initial limit 0 MW

- Constraint: Montgomery to Clarence 230 kV Line
- Contingency: Montgomery to Winnfield 230 kV Line
- Redispatch applied: 2,000 MW of generation

Re-dispatched limit 2,441 MW

- Constraint: Mount Olive to Vienna
- Contingency: Mount Olive to El Dorado
- Re-dispatch applied 2,000 MW of generation
- Re-dispatched generation in AMMO, EES, LAGN, & CLEC



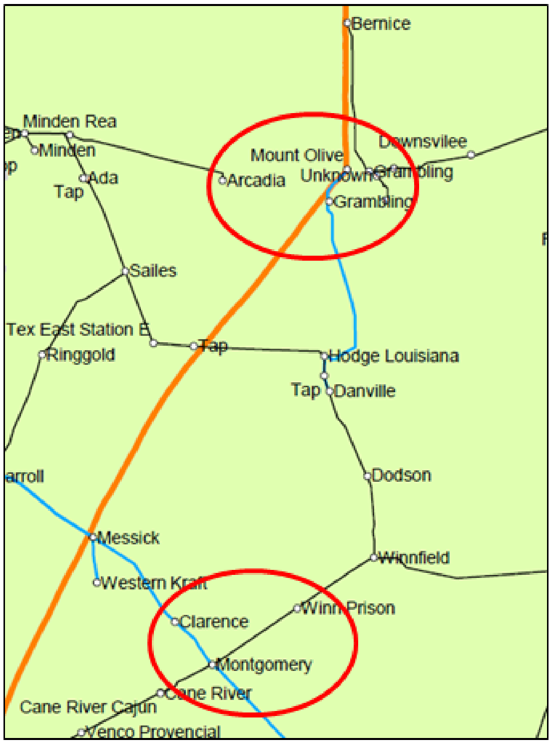
Zone 9 – TX, LA, MS

Initial limit 3,193 MW

- Constraint: Junction City to Bernice 115 kV Line
- Contingency: Mount Olive to El Dorado 500 kV Line

Re-dispatched limit 3,193 MW

- No re-dispatch available



C.5: 2016-17 Detailed CEL Results

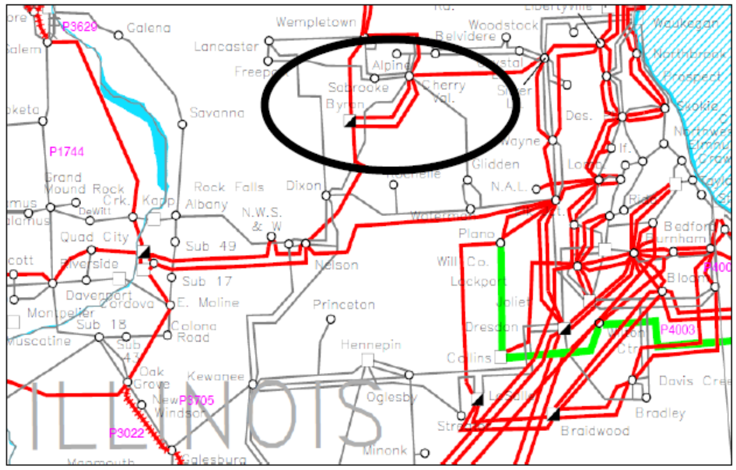
Zone 1 – MN and ND

Initial limit 0 MW

- Constraint: Byron to Cherry Valley R
- Contingency: Byron to Cherry Valley B

Re-dispatched Limit 350 MW

- Constraint: Briggs Road to Mayfair 161 kV Line
- Dispatch 2,000 MW in XEL, SMMPA, GRE, ITCM, MEC, & DPC



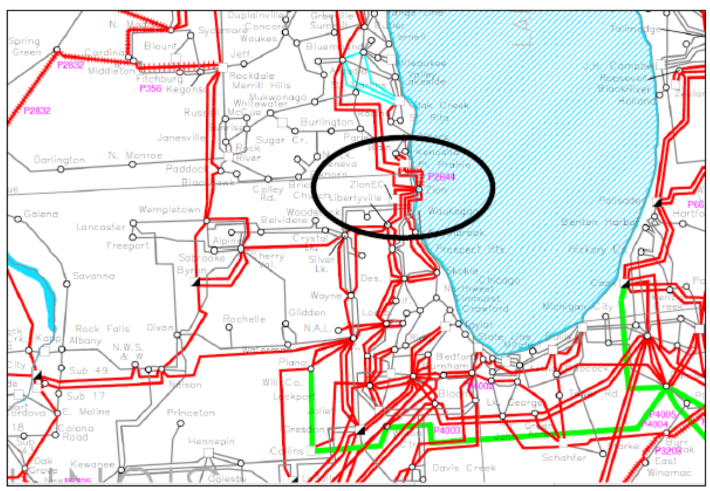
Zone 2 – WI and MI

Initial limit 867 MW

- Constraint: Zion Station to Zion Energy Center
- Contingency: Zion Station to Pleasant Prairie

Re-dispatched Limit 1,858 MW

- Constraint: Zion Station to Zion Energy Center
- Contingency: Zion Station to Pleasant Prairie
- Total generation re-dispatch of 2,000 MW



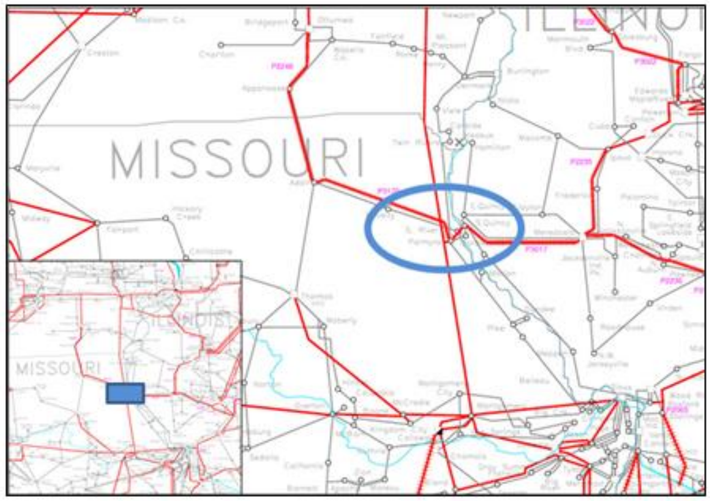
Zone 3 – IA & MN

Initial limit 869 MW

- Constraint: Palmyra Transformer
- Contingency: Montgomery to Spencer

Re-dispatched Limit 1,983 MW

- Re-dispatch generation in ALTW, MEC, MPW, & AMMO
- Total generation re-dispatch of 1,184 MW



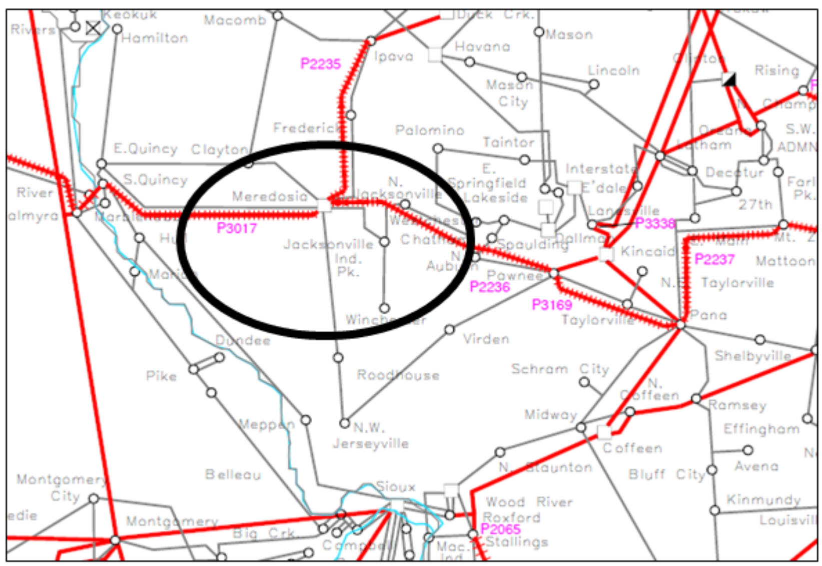
Zone 4 – IL

Initial limit 3,793 MW

- Constraint: Jacksonville – Westchester 138kV
- Contingency: Meredosia – Alsey PPI 138kV

Re-dispatched Limit 3,793

- No re-dispatch available



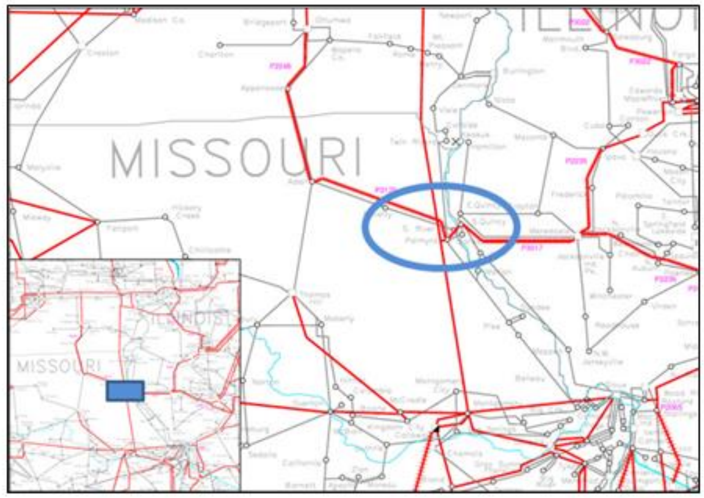
Zone 5 – MO

Initial limit 0 MW

- Constraint: Palmyra Transformer
- Contingency: Hull to South Quincy

Re-dispatched Limit 0 MW

- No dispatch available



Note: Modeling update analyzed after September 10 meeting modified zone 5 base interchange and available generation capacity. Model update included modeling of AMMO resources in their physical location (Illinois) to align with PRM calculation. Transfer is initially limited by constraint listed above, then is limited by generation.

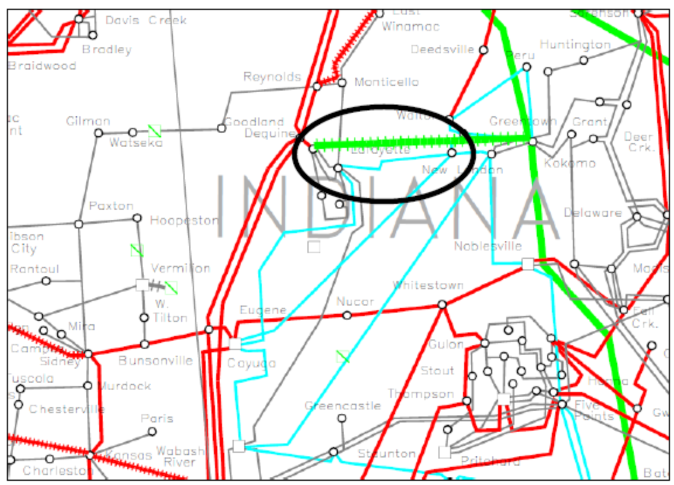
Zone 6 – IN & KY

Initial limit 2,360 MW

- Constraint: Lafayette – Westpoint 230kV
- Contingency: Eugene – Clay Sub 345kV

Current Limit 2,360 MW

- No dispatch available.



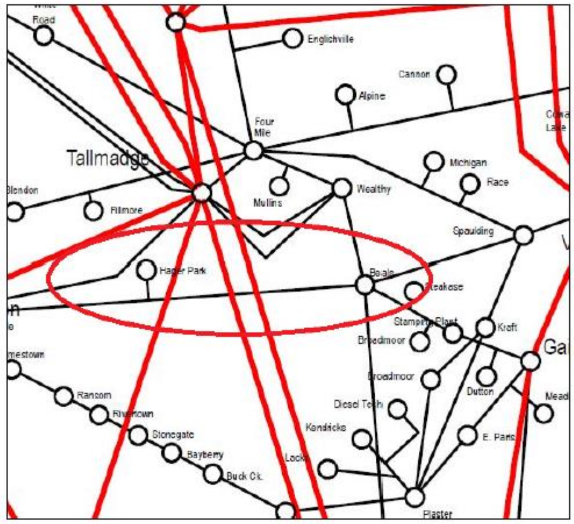
Zone 7 – MI

Initial limit 3,399 MW

- Constraint: Dorr Corners Jct to Beals 138kV Line
- Contingency: Argenta to Tallmadge 345kV Line

Re-dispatch Limit 3,399

- No dispatch availible



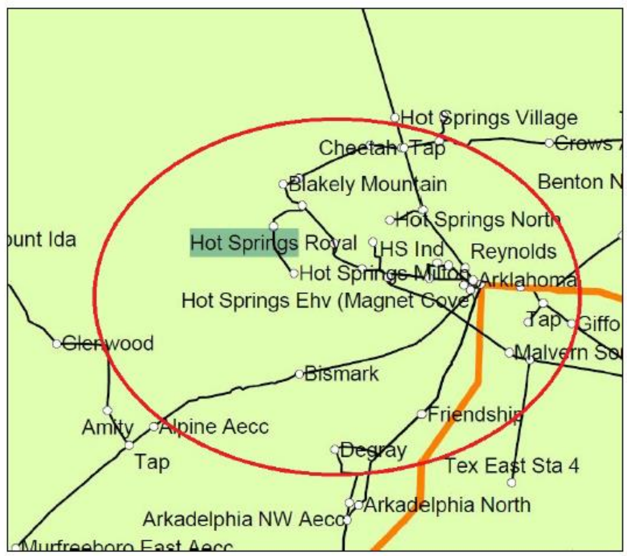
Zone 8 – AR

Initial limit 2,761 MW

- Constraint: Hot Springs East Bus to Butterfield 115 kV Line
- Contingency: Sheridan to Magnet Cove 500 kV Line

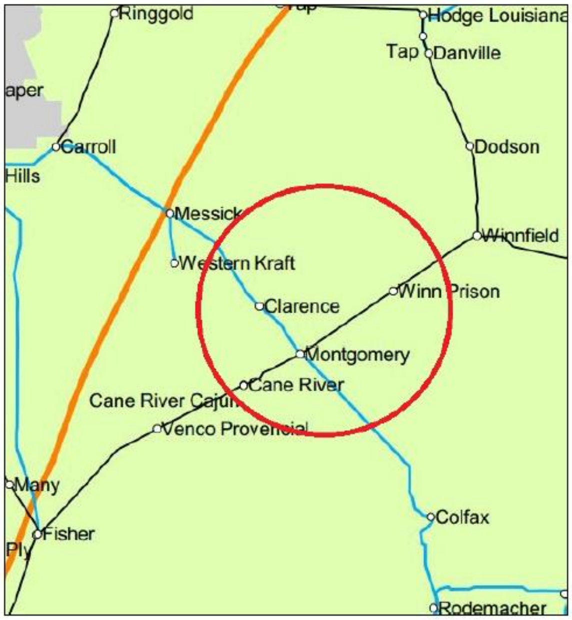
Current limit 3,494 MW

- Re-dispatch in EES
- Total Re-dispatch 2,000 MW



Zone 9 – TX, LA, MS

- **Initial Limit 1,678 MW**
  - Constraint: Montgomery to Clarence 230 kV Line
  - Contingency: Montgomery to Winnfield 230 kV Line
- **Current limit 2,511 MW**
  - Constraint: Ray Braswell EHV 500/115 Transformer
  - Contingency: Ray Braswell EHV – Lakeover EHV 500kV
  - Re-dispatch generation in EES & CLEC
  - Total re-dispatch generation of 1,133 MW



Appendix D Compliance Conformance Table

Requirements under: Standard BAL-502-RFC-02	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2015 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2015 through May 2016 and beyond. Analysis of Planning Year 2015 is in Sections 5.1 and 6.1 Analysis of Future Years 2016-2024 is in Sections 5.3 and 6.1
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a “one day in 10 year” criterion.)	Section 4.5 of this report outlines the utilization of LOLE in the reserve margin determination. “These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.”
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of load probability.	Section 4.3 of this report “Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.”
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.5.1 of this report “The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.”
R1.2 Be performed or verified separately for each of the following planning years	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In sections 5.1 and 6.1, a full analysis was performed for planning year 2015.

Requirements under: Standard BAL-502-RFC-02	Response
R1.2.2 Perform an analysis or verification at a minimum for one year in the two- through five-year period and at a minimum one year in the six- though 10-year period.	Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2016, 2017 and 2024.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	Analysis was performed
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In section 4.3 of this report: "For the 2015-2016 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by Load Serving Entities (LSE) through the MECT tool." Load Forecast Uncertainty – A detailed explanation of the LFU calculations is given in section 4.3.1 as well as in Appendix A. Load Diversity/Seasonal Load Variations - Section 4.3 of this report details the historic hourly load profiles used with their inherent diversity and seasonal variations. "Local Resource Zones 1 through 7 used the 2005 historical load shape while zones 8 and 9 used the 2006 historical load shape. For MISO North/Central, the 2005 load shape provides a typical load shape for the North/Central region as well as inherent conservative external support due to external areas. With the integration of MISO South, MISO chose to use the 2006 historical shape as the 2005 shape represented an extreme weather year for the South region due to Hurricane Katrina." Demand Modeling Assumptions/Curtailable and Interruptible Demand – All Load Modifying Resources must first meet registration requirements through Module E. As stated in section 4.2.6: "Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration."

Requirements under: Standard BAL-502-RFC-02	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 4.2. details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in section 4.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Section 3 of this report details the transfer analysis to capture transmission limitations that prevent the delivery of generation reserves. The results from this analysis are shown in section 3.3.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of planned transmission addition assumptions is detailed in section 3.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RFC-02	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (load) response programs not included in R1.3.1 • Sensitivity to resource outage rates •Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2. The use of demand response programs are mentioned in section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in section 4.5.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category A (system intact) and Category B (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in sections 5 and 6.

Requirements under: Standard BAL-502-RFC-02	Response
R1.7 Document that all load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in sections 5 and 6; the balance of MISO Reliability Coordination loads are included among the loads in the external Zone 1 “ExA MRO” of Figure 4.4-2.
R2 The Planning Coordinator shall annually document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis.	In Section 5 and 6, the peak load and estimated amount of resources for planning years 2015, 2016, 2017 and 2024 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in Year One through 10.	Section 5.3 and Table 5.3-1 shows the three calculated years, and estimated in-between years, by interpolation.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.3 and Table 5.3-1 shows the three calculated years in red-font text.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	The 2015 LOLE Study Report documentation is posted on November 1 prior to the planning year.

Appendix E Acronyms List Table

BA	Balancing Authority
BPM	Business Practice Manual
BTMG	Behind-the-Meter Generation
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
CSA	Coordinated Seasonal Assessment
DF	Distribution Factor
DSM	Demand-Side Management
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
EV	Energy Velocity
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansio Plan
MRO	Midwest Reliability Organization
MW	Megawatt
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corp.
NSI	Net Scheduled Interchange

OMS	Organization of MISO States
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
PSS MUST	Power System Simulator for Managing & Utilizing System Transmission
RCF	Reciprocal Coordinating Flowgate
RPM	Reliability Pricing Model
RRS	Reserve Requirement Study
RTO	Regional Transmission Operator
SERC	SERC Reliability Corporation
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity