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FILE NO. ER-2014-0258

REBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

**UNION ELECTRIC COMPANY
d/b/a Ameren Missouri**

St. Louis, Missouri
January, 2015

NP

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REBUTTAL TESTIMONY

OF

JAIME HARO

FILE NO. ER-2014-0258

I. INTRODUCTION

1

2 **Q. Please state your name and business address.**

3 A. My name is Jaime Haro. My business address is One Ameren Plaza,
4 1901 Chouteau Avenue, St. Louis, Missouri 63103.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am Senior Director, Asset Management and Trading for Union Electric
7 Company d/b/a Ameren Missouri (“Ameren Missouri” or “Company”).

8 **Q. Are you the same Jaime Haro who filed direct testimony in this case?**

9 A. Yes, I am.

10 **Q. What is the purpose of your rebuttal testimony in this proceeding?**

11 A. The purpose of my rebuttal testimony is to address (a) the common
12 argument made by Staff witness Erin L. Maloney and Missouri Industrial Energy
13 Consumers (“MIEC”) witness Nicholas L. Phillips in support of including margins from
14 bilateral and financial swap transactions in the Net Base Energy Cost (“NBEC”) against
15 which changes are tracked in the Company's fuel adjustment clause (“FAC”) (I will also
16 address a separate load and generation forecasting deviation adjustment proposed by Mr.
17 Phillips alone); (b) Mr. Phillips’ proposal to expand the “Polar Vortex” adjustments to
18 natural gas and spot future prices, and to Midcontinent Independent System Operator,
19 Inc. (“MISO”) Market Settlement Charge Types; (c) Sierra Club witness Ezra D.

1 Hausman's idea to remove the "must-run" status of the Company's coal-fired units when
2 modeling offers into the MISO market; (d) Office of Public Counsel ("OPC") witness
3 Lena Mantle's claims regarding the volatility/uncertainty of various FAC components;
4 and (e) MIEC witness James Dauphinais' recommendation that certain transmission
5 charges and revenues should be removed from the FAC.

6 **II. PROPOSED ADJUSTMENTS FOR BILATERAL TRANSACTIONS**
7 **AND FINANCIAL SWAPS**

8 **Q. What are the components of net off-system sales revenues?**

9 A. As noted in my direct testimony, our proposed net off-system sales
10 revenues are comprised of the following components:

- 11 1) net energy sales revenues (obtained from the PROSYM model results
12 sponsored by Ameren Missouri witness Mark Peters in his direct
13 testimony);
- 14 2) capacity sales revenues;
- 15 3) ancillary services revenues;
- 16 4) real time RSG MWP¹ margins; and
- 17 5) other miscellaneous MISO revenues.

18 **Q. Have other parties recommended adjustments to this list?**

19 A. Yes. MIEC witness Nicholas Phillips proposes to include an adjustment
20 for normalized real time load and generation deviations as well as for normalized financial
21 swap and bilateral margins. Staff Witness Erin Maloney has also proposed an adjustment
22 for normalized swap and bilateral margins.

23 **Q. What is your understanding of the purpose of these proposed**
24 **adjustments?**

¹ Revenue Sufficiency Guarantee Make Whole Payments.

1 A. It is my understanding that the proponents of these adjustments contend
2 that making the adjustments will incrementally improve the calculation of NBEC, by
3 accounting for certain factors which by their nature cannot be accounted for in the
4 PROSYM model results.

5 **Q. Are there other adjustments to the PROSYM model results which are**
6 **made for arguably the same purpose?**

7 A. Yes. In terms of net OSSR,² the PROSYM model outputs net sales and
8 purchases of energy at a spot price. It does not account for ancillary service revenues,
9 capacity revenues, real time RSG-MWP margins, or miscellaneous MISO revenues. All
10 four of these items are accounted for outside of the model with adjustments that have been
11 included since the inception of the FAC. Each of these adjustments is made to account for
12 a source of revenue not captured in the PROSYM model, and thus to incrementally
13 improve the accuracy of the NBEC calculation.

14 **Q. If there are other adjustments which are made outside of the model,**
15 **does that necessarily mean any adjustment that is purported to incrementally**
16 **improve the calculation of NBEC should be included?**

17 A. No. It would be inappropriate to adjust NBEC simply based on an
18 assertion that the model does not account for a particular source of potential revenue.
19 Such adjustments should only be made if it can be demonstrated that not only does the
20 model not account for such revenues, but that the source of the revenues can reasonably be
21 expected to continue into the future and the inclusion of the adjustment is reasonably
22 expected to improve the accuracy of the NBEC calculation.

² Off-system sales revenues, as defined in the Company's FAC tariff in Factor OSSR.

1 **Q. Do Mr. Phillips' and Ms. Maloney's proposed adjustments meet this**
2 **threshold?**

3 A. I believe that it is reasonable to assert that the PROSYM model does not
4 account for these adjustments and that the factors giving rise to the adjustments are
5 expected to continue into the future. I am less certain that the inclusion of these
6 adjustments can be expected to consistently or reliably improve the accuracy of the
7 NBEC, a point which I also discussed in my rebuttal testimony in File No. ER-2012-
8 0166.

9 **Q. Can you please elaborate on these points?**

10 A. Yes. The PROSYM model optimizes and essentially presumes a perfect
11 dispatch of Ameren Missouri's generating resources, given a set of operating
12 characteristics, fuel prices, and energy prices. Since Ameren Missouri clears the over-
13 whelming majority of the megawatt-hours it sells from its generation and the megawatt-
14 hours it buys for its load in the day-ahead market, the model utilizes an energy price input
15 assumption based on day-ahead prices.

16 The model neither accounts for operating conditions which vary from "perfect,"
17 nor does it account for sales which are priced at other than a day-ahead spot price. The
18 existing adjustment for real time RSG-MWP margins and Mr. Phillips' proposed
19 adjustment for real time load and generation deviations attempt to account for revenues
20 arising from imperfect operating conditions, while the proposed adjustment from MIEC
21 and Staff for bilateral and swap margins seeks to account for revenues arising from prices
22 other than those established by the day-ahead spot market.

23 I am certain that we will continue to experience operational impacts which reflect
24 the imperfect reality in the operation of the system and markets. I am also certain that as

1 long as Ameren Missouri continues to seek to hedge a portion of the price exposure for
2 its future net off-system sales, we will also continue to see transactions which are priced
3 at other than the day-ahead spot market price.

4 What I am not certain of is whether these differences will remain at a stable level,
5 or even consistently represent incremental revenue as opposed to incremental cost. This
6 is why it is not clear that including the adjustments recommended by Mr. Phillips and
7 Ms. Maloney will actually consistently improve the accuracy of the NBEC calculation,
8 and it is why I did not include them in my direct testimony.

9 **Q. Is Ameren Missouri nevertheless willing to include these proposed**
10 **adjustments in the calculation of the NBEC?**

11 A. While it is not clear that these meet all of the criteria I outlined above for
12 inclusion, it is also difficult to establish that the criteria are not met. Therefore, Ameren
13 Missouri is willing to include an adjustment for these items, conditioned upon the
14 following:

15 1) Either all of the following adjustments should be included in the NBEC or
16 none of them should be included: real time RSG-MWP margins, real time load
17 and generation deviations and bilateral and swap margins. If we (Staff, MIEC,
18 and the Company) are going to conclude that it's more probable than not that
19 including these kinds of items better fulfills the spirit of "perfecting" the
20 estimation of OSSR in the NBEC, then all such items should be included rather
21 than picking and choosing only some of such items.

22 2) The calculation of these adjustments must be corrected as discussed below
23 and in Ameren Missouri witness Mr. Peters' rebuttal testimony. Mr. Peters
24 discusses needed corrections to the calculation of the real time RSG-MWP margin

1 and real time load and generation deviation adjustments. The bilateral and swap
2 margin calculation must also be corrected, as I discuss below.

3 3) The value for all of these adjustments should be determined as of the end
4 of the true-up period (December 31, 2014), and also reflect a consistent treatment
5 of the Polar Vortex anomaly.

6 **Q. Have you calculated an interim value for the bilateral and swap**
7 **margins?**

8 A. Yes. I have calculated a normalized value through the true-up period of
9 \$1.1 million for bilateral margins and \$3.2 million for financial swaps, for a total of \$4.3
10 million.

11 **Q. You indicated above that a correction to the calculation of this**
12 **proposed adjustment was required. Can you please discuss what corrections are**
13 **needed?**

14 A. Yes. While I generally agree with the methodology used by Mr. Phillips
15 to calculate his adjustment, I disagree with Ms. Maloney's methodology for calculating
16 the bilateral margin portion of her adjustment – in large part because Ms. Maloney did
17 not actually calculate a bilateral *margin*, but rather, she calculated a level of normalized
18 bilateral *revenue*. (For the purpose of this testimony, it should be understood that the term
19 “bilateral” refers to “physical bilateral transactions,” since the “financial swaps” actually
20 include “financial bilateral transactions.”)

21 **Q. Please explain why Ms. Maloney did not calculate a bilateral margin.**

22 A. Because Ms. Maloney failed to utilize the actual prices at which these
23 transactions were made and she also failed to account for the costs that are necessarily
24 incurred to complete these transactions.

1 **Q. Please expand on your first point.**

2 A. Bilateral transactions and financial swaps are hedging mechanisms to
3 mitigate some of the volatility from OSSR, but they do not replace the off-system energy
4 sales themselves. Since PROSYM computes the revenues and the fuel cost for the off-
5 system energy sales, the bilateral transactions and financial swaps should be calculated as
6 a margin derived from the difference between the sales price and the settling index.

7 Since these bilaterals are physical transactions, the energy and the associated fuel
8 has already been accounted for in the production cost model, whether PROSYM or
9 REAL TIME (the model used by Staff and MIEC). However, the models price the
10 energy at the day-ahead spot market price. Ms. Maloney first calculated a normalized
11 annual volume of bilateral sales, net of bilateral purchases – energy which is already
12 accounted for in the model. She then multiplied this volume not by the difference
13 between the price that Ameren Missouri would have received from the spot market
14 (absent the bilateral transaction) and the actual transaction price (the margin), but rather
15 by the simple annual average market price for energy that she calculated as an input into
16 Staff's REAL TIME production cost model. Setting aside Ameren Missouri's
17 disagreement with Staff's methodology for calculating the average market price for
18 energy as discussed by Mr. Peters in his rebuttal testimony, what Ms. Maloney has done
19 is to calculate the spot market revenue that the normalized amount of bilateral
20 transactions would receive, if they were evenly distributed across the entire year (same
21 amount in each hour). However, since the energy is already accounted for in the
22 production cost model, she is double-counting the sales revenue, in addition to
23 misapplying the price.

24 **Q. How should the bilateral margin be calculated?**

1 A. At its core, the calculation for the bilateral margin is not materially
2 different from that for the financial swap margin. The margin is calculated by taking the
3 difference between the actual price received and the price that would have been received
4 had the transaction settled at the spot market for the CPNode³ specified by the transaction
5 and multiplying that difference by the volume. (For a bilateral purchase, the calculation
6 is reversed – it is a comparison of the fixed price paid to the spot price which would have
7 been paid.)

8 **Q. Did Mr. Phillips use the same methodology as you did?**

9 A. Yes, he did.

10 **Q. You indicated that all adjustments should reflect a consistent**
11 **treatment of the Polar Vortex anomaly. What should that treatment be?**

12 A. For those adjustments using 12 months of historical data, I support Mr.
13 Phillips' approach of excluding data for the months of January, February, and March of
14 2014 from the true-up period and annualizing the values from the remaining nine months.
15 For those adjustments using 36 months of historical data, I support the methodology
16 Ameren Missouri and Mr. Phillips utilized for adjusting energy prices – that is the market
17 prices for the period of January 1, 2014 – March 31, 2014 have been replaced with the
18 average prices for the applicable peak period by month, from the prior two years, January
19 2012 – March 2012, and January 2013 – March 2013. (I would note here that my direct
20 testimony inadvertently indicated that only data from January 2012 – March 2012 was
21 used as a replacement. I have confirmed that the actual calculation did indeed include
22 both years' data as noted by Mr. Phillips).

³ Commercial Pricing Node (CPNode) is used by the MISO as the location (or a collection of locations) at which market activities, including load and generation, are measured and settled. The MISO publishes

1 **III. EXPANDED ADJUSTMENTS FOR POLAR VORTEX**

2 **Q. Mr. Phillips states in his direct testimony that wholesale electric**
3 **energy prices are not the only costs highly sensitive to the Polar Vortex and**
4 **proposes that both natural gas price assumptions and MISO Market Settlement**
5 **Charge Types should be adjusted to account for the Polar Vortex. Do you agree?**

6 A. Yes. These are appropriate adjustments.

7 The natural gas price assumptions utilized in the true-up period run should be
8 developed in a manner similar to that utilized to develop the market price of energy for
9 the model – that is, the values for each month in the period of January 1, 2014 – March
10 31, 2014, should be replaced with the average value for that same month from the two
11 prior years.

12 MISO Market Settlement Charge Types should be adjusted using the
13 methodology proposed by Mr. Phillips using the values for the true-up period ending
14 December 31, 2014.

15 **IV. COMMITMENT STATUS: “MUST-RUN” VS “ECONOMIC”**
16 **OF COAL-FIRED GENERATION**

17 **Q. Can you explain what the terms “Must-Run” and “Economic” refer to**
18 **in the context of “Commit Status” within the MISO offers?**

19 A. Yes. When a generation owner offers a unit into the MISO market, it can
20 choose among several “commitment status” options. Two of these options are “Must-
21 Run” and “Economic.” The Must-Run status tells the model utilized by MISO as part of
22 the process of dispatching units in its footprint that the unit will run despite any margin
23 calculation that the model performs, whereas the Economic status allows the MISO

locational marginal prices (“LMPs”) (both day-ahead and real time) for each CPNode.

1 model to de-commit (issue a stop order for) a generator when the revenues generated are
2 lower than the offered costs.

3 **Q. Why would the Company offer its coal units to the MISO market**
4 **under an Economic status versus a Must-Run status?**

5 A. In general, the Company wants the units clearing in the market when they
6 are profitable and benefitting ratepayers. The vast majority of the time, due to the
7 relatively low cost of these specific Ameren Missouri coal-fired generators, these units
8 would clear in the day-ahead market whether they are offered as Economic or as Must-
9 Run. There are times when a given unit would not clear in the day-ahead market, as the
10 margin between the LMP⁴ revenue and the as-offered cost for that 24-hour market
11 clearing period becomes negative. As discussed below, however, merely looking at one
12 24-hour period is not appropriate. The Company must look past that time period and see
13 if this negative margin condition is projected to exist for a prolonged period of time.

14 **Q. Dr. Hausman claims that using a Must-Run commit status “results in**
15 **a departure from short-run, least-cost dispatch, and thus increases overall**
16 **production cost.” Do you agree?**

17 A. No. Dr. Hausman fails to account for the limitations of the MISO
18 methodology and the role that unit startup costs play in overall production cost. As I will
19 demonstrate below, the use of an Economic commit status in MISO market methodology
20 can actually increase overall production cost, while the use of the Must-Run can decrease
21 overall production cost.

⁴ The LMP is the wholesale price of energy established in the MISO market.

1 **Q. Please explain the limitation of the MISO methodology.**

2 A. There are several reasons, including operational reasons which are
3 addressed in the rebuttal testimony of Ameren Missouri witness Chris Iselin, which
4 support Ameren Missouri utilizing a Must-Run commit status. These operational
5 considerations are particularly noteworthy when we acknowledge the significant
6 limitation in the algorithm utilized by MISO in dispatching generators in its footprint. As
7 detailed in MISO Business Practices Manual ("BPM") 002, Energy and Operating
8 Reserve Markets, the model will only optimize the commitment of a resource within a
9 very narrow 24-hour window; that is, for the next calendar day. In doing so, MISO's
10 model does not take into consideration the market's expectation of future market prices
11 or the cost of restarting the generator after it had determined that a generator should be
12 turned off. While it does consider whether a unit has met its minimum up time
13 requirement before de-committing a unit, it does not take into consideration that this
14 same unit's minimum down time and/or startup costs may make it unavailable for
15 commitment for the following market day (two days into the future) during a period when
16 it would be profitable to operate.

17 The Company is not hampered by these time restrictions, however, and can make
18 a decision based on the review of data over a much longer period of time.

19 **Q. Can you provide an example of how the MISO methodology increases**
20 **net cost for Ameren Missouri?**

21 A. Yes. Consider the example where a generating unit's as-offered
22 production cost for a calendar day is less than the revenue it would receive from the
23 MISO market resulting in a total "loss" for the day of \$1,200 if it were Must-Run. If,

1 however, the unit commit status was Economic and we were to rely on the MISO model's
2 algorithm, this unit would not run on that day and that "loss" would be avoided.

3 On day two, market prices rise such that the difference between the as-offered
4 cost, not including a startup cost of \$100,000, and the revenue from being cleared is
5 \$10,000. The MISO methodology will not start the unit as it cannot cover the startup cost
6 that would now have to be incurred since the unit was turned off the day before, so it
7 remains offline even though it would make money that day had it been running.

8 On day three, this difference rises to \$110,000, and the unit clears in the market
9 and is dispatched to run.

10 The margin for these three days totals \$10,000. Days one and two have zero
11 margin as the unit did not run, while the margin on Day three was \$10,000 after
12 subtracting the \$100,000 cost to start the unit.

13 Had the unit been Must-Run, the total margin for these three days would have
14 been \$118,800. On day one, there would have been a \$1,200 loss, on day two a \$10,000
15 gain, and \$110,000 gain on day three. Since the unit never came off line, there would not
16 have been a startup charge.

17 In this simple example, the increase in net energy cost for just those three days
18 from letting the MISO methodology dispatch the unit would be \$108,800.

19 If we consider that the MISO methodology would never restart the unit until it
20 overcame the \$100,000 startup cost, the avoidable loss could be extreme. The worst case
21 scenario would be a situation where future daily margins remain just under the \$100,000
22 amount for a protracted period of time. If potential margins averaged \$75,000 a day for
23 the next 30 days, but never exceeded \$100,000, the avoidable loss would be over \$2
24 million from not offering the unit as Must-Run.

1 **Q. How can these kinds of lost opportunities be prevented?**

2 A. The best way is to designate the unit as Must-Run, which prevents the
3 MISO algorithm from de-committing it.

4 **Q. Are there other reasons why 24 hours is an inappropriate time period
5 for considering whether or not to de-commit a coal-fired generation resource?**

6 A. Yes. First, different units have varying minimum up and down times. As
7 noted above, Mr. Iselin's testimony discusses operational considerations for these units
8 which restrict our ability to cycle them on and off in 24-hour periods. Those
9 considerations, in combination with the limitations of the MISO market clearing process
10 (most importantly its failure to consider the cost to restart a unit when not clearing it in
11 the day ahead market), are why the Company does not leave the commitment of these
12 units to the MISO process, and instead considers a multi-day period when reviewing the
13 possibility of taking a unit off line for economics.

14 **Q. Dr. Hausman suggests that the Company should model ** [REDACTED]
15 [REDACTED] ** with an Economic status as opposed to Must-Run. Do you agree?**

16 A. No. Ameren Missouri witness Mark Peters addresses this issue in his
17 rebuttal testimony, where he quotes the Company's response to Data Request SC-008,
18 which read in part as follows: "** [REDACTED] ** remain
19 must run units in actual operations due to their operating characteristics, high cost to
20 restart and expected increase in forced outages due to unit cycling. As such, it would be
21 neither meaningful, nor appropriate to model them in a manner that differs from expected
22 operations." The point is that when we model the units for a rate case, the goal is to
23 model them *as they are expected to operate in the market.*

NP

1 A. In the Company's last rate case, File No. ER-2012-0166, Mr. Dauphinais
2 argued that certain transmission charges (charged by MISO for power used to serve the
3 Company's load) were ineligible for inclusion in the FAC due to the terms of the FAC
4 tariff that was then in effect. In support of his argument, he claimed that the then-
5 effective FAC tariff provision required exclusion of these charges because it contained
6 the following provision: "...excluding capacity charges for contracts with terms in
7 excess of one (1) year incurred to support sales to all Missouri retail electric
8 generations."⁵ The Commission Staff disagreed that the "capacity" charges referred to in
9 this section of the tariff referred to "transmission capacity," and pointed out that the
10 reference was to generation capacity. The Commission agreed, stating that "the tariff's
11 exclusion of capacity charges for contracts with terms in excess of one year refers to
12 generation capacity, not transmission capacity."⁶ As noted, Mr. Dauphinais' argument at
13 the time was focused on transmission charges for power used to serve our load, but in his
14 surrebuttal testimony, when discussing off-system sales, he made at least three statements
15 that transmission charges associated with off-system sales *are* appropriately recovered in
16 the Company's FAC. All of those sworn statements are at odds with his new position in
17 this case.

18 **Q. Where did he make those statements?**

19 A. The first such statement is found on page 13 of that surrebuttal testimony,
20 where in his response to the question of "what transmission expenses may the Company
21 include in its FAC", he stated: "These are incremental transmission charges that the
22 Company would not incur for reasons other than to make certain power purchases and

⁵ Ex. 518, File No. ER-2012-0166 (Dauphinais Surrebuttal), pp. 13-14.

⁶ *Report and Order*, File No. ER-2012-0166, p. 85.

1 off-system sales on behalf of its retail customers. As such, they are appropriately
2 recovered in the Company's FAC and included in the Company's NBFC value."⁷ Now,
3 in this case, he claims that the very same "incremental transmission charges . . . to make .
4 . . off-system sales . . ." should be excluded.

5 The second instance is found on page 14 of his surrebuttal testimony, where he
6 testified that "MISO transmission charges associated with the short-term transmission
7 service necessary to support power purchases or off-system sales are incremental costs
8 directly related to the Company's fuel and purchased power cost less off-system sales
9 margins to which the Company attributes much of the cost savings that has come from
10 MISO participation."⁸ Again, he supported including those transmission charges in the
11 FAC, but now he has reversed course.

12 The third instance is found of page 16 of his surrebuttal testimony. When asked if
13 he objected to the inclusion of certain transmission charges to "support the Company's
14 off-system sales to entities not located in MISO and PJM in its FAC and NBFC," he
15 stated "No. Provided they are prudently incurred, those particular MISO Schedule 26 and
16 26-A charges are appropriately recoverable through the Company's FAC. They are
17 incremental charges directly associated with the Company's fuel and purchased power
18 costs less off-system sales revenues."⁹ This, too, reflects a position totally opposite to his
19 current position regarding transmission charges associated with off-system sales.

⁷ Ex. 518, File No. ER-2012-0166, p. 13, l. 18-22.

⁸ *Id.*, p. 14, l. 15-19.

⁹ *Id.*, p. 16, l. 6-9.

1 Put another way, under Mr. Dauphinais' new position, the off-system sales
2 revenues would be credited to customers (100% of them in base rates and 95% of the
3 changes through the FAC), but the transmission charges associated with them would be
4 mis-matched and outside the FAC. This is inappropriate.

5 **Q. So is it your position that these transmission charges for off-system**
6 **sales belong in the FAC?**

7 A. Yes, as they have been since the inception of the FAC. Our position on
8 this has never changed. Mr. Dauphinais was right when he previously testified that these
9 are incremental transmission charges that the Company would not incur for reasons other
10 than to make certain off-system sales on behalf of its retail customers.

11 **Q. Having addressed transmission charges associated with off-system**
12 **sales, can you please describe Mr. Dauphinais' position about transmission charges**
13 **for purchased power?**

14 A. Mr. Dauphinais claims that the vast majority of the transmission charges
15 that Ameren Missouri is assessed by the MISO should be excluded from the FAC by
16 claiming that these are not charges associated with purchased power, but rather, that they
17 are simply associated with the transmission of energy from Ameren Missouri's own
18 generators to its own retail load. I disagree.

19 **Q. Please explain why you disagree.**

20 A. First of all, these charges have been in the FAC since its inception, nearly
21 six years ago. The Commission itself has recognized that this is proper, as reflected in its
22 *Report and Order* in our last rate case.¹⁰ Second, Mr. Dauphinais' argument ignores the

¹⁰ Report and Order, File No. ER-2012-0166, pp. 84-85.

1 reality of how megawatt-hours are sold and purchased in the MISO market. As a
2 function of the MISO markets, Ameren Missouri purchases all of the megawatt-hours
3 used to serve its load requirement from the MISO market. The Commission recognized
4 this reality in its *Report and Order* in our last rate case, stating that "Ameren Missouri
5 has access to a transparent energy market where it can acquire power to serve its load and
6 sell power off-system."¹¹ Except for megawatt-hours sold pursuant to physical bilateral
7 contracts with those outside MISO, Ameren Missouri sells all of the megawatt-hours it
8 generates to the MISO market. As I explained in the Company's last rate case, the MISO
9 market operates like a large pool of water – all of the water (power) that is produced/sold
10 is poured into the pool and then the utility draws water (power) from that pool to serve its
11 customers (i.e., its load). The transmission charges Mr. Dauphinais wants to exclude
12 would not be incurred by Ameren Missouri but for the fact that they are assessed on
13 every megawatt-hour that Ameren Missouri buys from the MISO market (put another
14 way, for every megawatt-hour Ameren Missouri draws from the MISO pool). The
15 Commission also recognized this in our last case: "As part of its membership in MISO,
16 Ameren Missouri incurs certain transmission charges for the load it serves through the
17 MISO market."¹²

18 **Q. Can you please provide some background on Ameren Missouri's**
19 **participation in MISO?**

20 A. Yes. FERC Order 888 (issued in 1996) and FERC Order 2000 (issued in
21 2000) set FERC policy to encourage utilities to participate in RTOs. Those orders
22 provide the underpinnings of the current open access transmission and led to the

¹¹ *Report and Order*, File No. ER-2012-0166, pp. 84-85.

¹² *Id.*, p. 83.

1 development of transparent wholesale energy (and related) markets, such as those
2 operated by MISO since 2005. With this Commission's permission, Ameren Missouri
3 joined MISO in 2003 based on a cost-benefit study that showed that customers were
4 better off with Ameren Missouri in MISO. The Commission has twice since extended
5 Ameren Missouri's participation in MISO, also based upon cost-benefit study results
6 indicating that MISO participation is beneficial, meaning that MISO-related benefits
7 outweigh MISO-related costs.¹³ Ameren Missouri will be filing additional cost-benefit
8 studies in 2017 when the Commission will again examine its RTO participation.

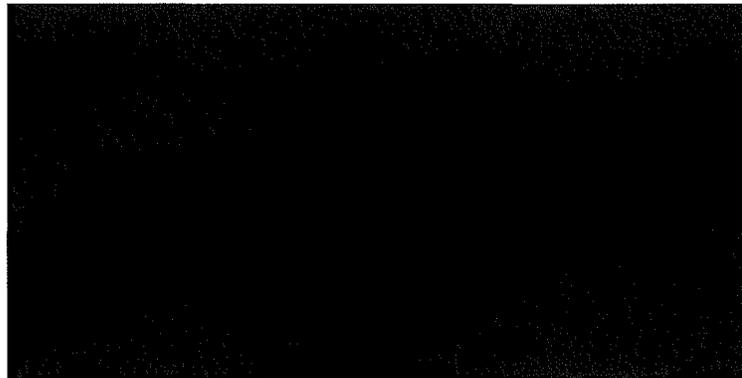
9 **Q. In the Company's last rate case, the Commission determined that**
10 **these transmission charges are large, that Ameren Missouri has little control over**
11 **them, and that they are volatile because no one knows for sure how much the MVP**
12 **projects will cost once construction is complete (*Report and Order*, File No. ER-2012-**
13 **0166, p. 88). Are those findings still correct?**

14 A. Yes, they are. As Mr. Dauphinais himself recognizes, transmission
15 charges in total are now about \$30 million annually, and are currently projected to more
16 than double (to about ****[REDACTED]**** annually) in the next five to six years. I have also
17 illustrated this using the normalized loads provided by Ameren Missouri witness Steve
18 Wills in connection with his direct testimony, and the projected rates for MISO Schedule
19 26A included in Mr. Dauphinais' testimony, which I have used to calculate a projected
20 total for these charges for the next few years. As the table shows, Ameren Missouri's
21 transmission charges from MISO (there are others, but this captures the largest

¹³ As the Commission recognized in its last order continuing its permission for Ameren Missouri to participate in MISO, the last study indicated there were \$105 million of net benefits over the three-year study period. *Report and Order*, File No. EO-2011-0128, p. 7.

1 source of the increase, Schedule 26A) can be expected to increase from more than ** 
2 ** in 2015 to over ** ** in 2018. I would note, however, that these
3 figures (and those Mr. Dauphinais relies upon) are estimates provided by the MISO and
4 as such are, uncertain – they could be materially higher or lower as they largely depend
5 on transmission construction that has not yet occurred and which could cost materially
6 more or less than currently estimated, a fact that the Commission itself recognized in its
7 order in our prior rate case.

**



**

8 **Q. Mr. Dauphinais seems to rely on the fact that MISO nets purchases**
9 **from the market against revenues received for sales to the MISO market from**
10 **Ameren Missouri's generating units when invoicing the Company for all of the**
11 **charges the Company incurs from MISO. Does this netting negate the fact that**
12 **Ameren Missouri purchases all of the megawatt-hours used to serve its load from**
13 **the MISO market?**

1 A. No, it does not. As I explain below, MISO's settlement statements, tariff¹⁴
2 and BPMs¹⁵ all recognize that the megawatt-hours generated from our plants are sold to
3 the market and that megawatt-hours are purchased from the market to serve our load.
4 That for billing and financial reporting purposes the sums are netted is irrelevant to the
5 operation of the market.

6 **Q. Does Mr. Dauphinais provide testimony that supports the conclusion**
7 **that Ameren Missouri buys all of its megawatt-hours to serve its load from the**
8 **MISO market?**

9 A. Yes. Mr. Dauphinais testifies on page 9 of his direct testimony that “In
10 each operating hour, Ameren Missouri offers energy production from all of its generation
11 facilities into the MISO market and clears all of its load in the MISO market.” In
12 laymen’s terms, to "clear" your load is to purchase energy to serve your load.

13 **Q. Mr. Dauphinais also testified that “(o)nly in an hour when Ameren**
14 **Missouri clears less generation MWh than load MWh does Ameren Missouri**
15 **purchase any power from MISO...” Is this statement correct?**

16 A. No. Mr. Dauphinais is either confusing or ignoring the difference between
17 gross purchases and netting for settlements and reporting.

18 **Q. Mr. Dauphinais points to one of Ameren Missouri witness Mark J.**
19 **Peters’ workpapers as identifying Ameren Missouri’s level of purchased power.**
20 **Does that workpaper indeed identify Ameren Missouri’s total purchased power?**

¹⁴ MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff is approved by the Federal Energy Regulatory Commission and is binding on market participants in the MISO market, such as the Company.

¹⁵ MISO issues Business Practice Manuals ("BPMs") which provide details about market operations that are not set forth in full in MISO's tariff. MISO's tariff refers to the BPMs for those details.

1 A. No. Mr. Dauphinais has ignored that the amount listed as purchased
2 power in that workpaper represents a *net* amount. As Mr. Peters stated in his direct
3 testimony, “Ameren Missouri is a market participant within the Midcontinent
4 Independent System Operator, Inc.'s (‘MISO’) markets. We purchase energy to serve our
5 entire load from the MISO market and separately sell all of our generation output into the
6 MISO market. For modeling purposes, however, we report only on a net basis...”

7 This netting is done as a matter of convenience, as it would otherwise require the
8 production cost model to be run twice to obtain the same result. The production cost
9 model could be run once with load and no generation to determine the amount of energy
10 purchased from the market to serve load, and a second time with generation and no load
11 to determine the amount of energy sold to the market. The hourly results of the two runs
12 could then be netted together to obtain a net output which could be compared to the
13 financial reporting amounts, which per FERC reporting requirements are netted.

14 **Q. If Ameren Missouri does indeed purchase its entire load requirement**
15 **from the MISO market, would Mr. Dauphinais’ own argument support the**
16 **inclusion of the associated transmission charges in the FAC?**

17 A. Yes. Mr. Dauphinais testified that “(o)nly Ameren Missouri’s wholesale
18 transmission expenses that are incurred to **transmit electric power it has purchased**
19 **from MISO** or other third-parties (i.e., Purchased Power) should be includable in
20 Ameren Missouri’s FAC as they are the only transportation costs for purchased power
21 that Ameren Missouri incurs.” (emphasis added). As I have explained, his contention
22 that only the "net" purchases are "purchased power" is wrong because we purchase all of
23 the power and we incur transportation charges on all of the power. His statement that

1 transmission charges for power purchased from MISO should be recovered through the
2 FAC is correct.

3 **Q. Has Mr. Dauphinais provided testimony in other proceedings which**
4 **demonstrate that Ameren Missouri in fact does purchase all of the power needed to**
5 **serve its purchases its load requirement from the MISO market?**

6 A. Yes. Mr. Dauphinais provided direct testimony in support of Noranda's
7 rate shift complaint (File No. EC-2014-0224). Beginning on page 4 of that testimony,
8 Mr. Dauphinais stated "*As a participant in the MISO Regional Transmission*
9 *Organization ('RTO'), Ameren Missouri must clear all of its generation and all of its*
10 *load in the MISO market.*" He went on to state "*the reduction in Ameren Missouri's*
11 *ANEC can be reasonably and conservatively estimated as the cost avoided by Ameren*
12 *Missouri by not having to clear the Noranda retail sales in its MISO market and*
13 *transmission settlements for its load.*" (ANEC is Actual Net Energy Cost).

14 In that same testimony, Mr. Dauphinais provides several examples to demonstrate
15 how an avoided cost would be calculated, including a description beginning on page 6 of
16 what would happen if a utility were to experience 100 megawatt-hour lower retail sales in
17 an hour, with generation output unchanged. He properly notes in this instance that "*(t)he*
18 *only thing that would change is that the utility will clear 900 MWh of retail load rather*
19 *than 1,000 MWh of retail load in the RTO market. The utility will continue to have no net*
20 *purchased energy cost, but will now have a 100 MWh net off-system energy sale because*
21 *in this hour it is clearing 1,000 MWh of generation but only clearing 900 MWh of retail*
22 *load.*" In the following question, Mr. Dauphinais was asked if net fuel cost savings
23 always appear as an increase in off-system energy sales margins. His response was:

1 *In my example, off-system energy sales increased by 100 MWh. If the same*
2 *retail sales reduction in another hour decreased the utility's net purchase*
3 *of energy by 100 MWh, the net fuel cost savings would appear in the*
4 *utility's accounting as a reduction in the utility's net purchased energy*
5 *costs rather than an increase in the utility's off-system energy sales.*

6 **Q. Please describe the significance of these three sections of**
7 **Mr. Dauphinais' testimony in File No. EC-2014-0224.**

8 A. These sections of his testimony are significant as they acknowledge that
9 Ameren Missouri clears (i.e., buys power for) *all* of its load in the MISO market, and that
10 a reduction in an actual purchase can be represented by a reported increase in net-off
11 system sales revenue or net purchased energy costs. Regardless of whether the change is
12 reported as a net increase in off-system sales or a reduction in net purchased
13 energy/power costs, the cause of the change is a reduction in *gross* purchased power from
14 the MISO. There could not be a reduction in gross purchased power if the power was
15 never purchased in the first place.

16 **Q. Does the MISO itself provide guidance on this question?**

17 A. Yes, both its Energy Markets Tariff ("EMT") and the MISO BPMs, which
18 contain additional details about the market's operation, reflect the reality that Ameren
19 Missouri purchases all of the megawatt-hours needed to serve its load from the MISO
20 market. For example, the very definition of the term "Bid" in the MISO tariff begins, "A
21 request to **purchase Energy** in the Day Ahead Energy and Operating Reserve Market"
22 (emphasis added). Similarly, the definition of Offer begins, "An offer, that is duly
23 submitted to the Transmission Provider consistent with this Tariff and the Business
24 Practices Manuals, to (a) sell Energy and Operating Reserve in the Energy and Operating
25 Reserve Markets at a specified price, location, quantity, and time period and shall include
26 (i) Generation Offers." The EMT also establishes MISO as the Energy Market

1 Counterparty, which is defined as “The Transmission Provider as the contracting
2 counterparty to Market Participants for all Market Activities contemplated by this Tariff,
3 solely in the Transmission Provider’s capacity as a principal and not as an agent for any
4 other party, consistent with the provisions of Section 6A.”

5 The definitions in the EMT for Day Ahead Energy and Operating Reserve
6 Market, Energy Offer, Fixed Demand Bid, Generation Offer, Offer, Real-Time Energy
7 Purchases, and Real-Time Energy and Operating Reserve Market, among others,
8 consistently recognize the sales we make to the market and the purchases (for all of our
9 load) we make from the market, while Section 6a of the tariff reinforces that MISO “is
10 the contracting party with Market Participants for Market Activities, and collects and
11 distributes all charges for Market Activities.” Those definitions are included in Schedule
12 JH-R1.

13 The MISO Energy and Operating Reserve Markets BPM also describes the
14 operation of the MISO market, and confirms that Ameren Missouri purchases its load
15 from the MISO.

16 For example, consider the definition of Fixed Demand Bid from the EMT and the
17 discussion of Demand Bids in part 4.3 of the BPM.

18 *Fixed Demand Bid: A request to **purchase a specified MWh quantity of***
19 ***Energy**, at specified locations in the Transmission Provider Region,*
20 *during specific Hours of the next Operating Day submitted to the Day-*
21 *Ahead Energy and Operating Reserve Market. Demand Bids may only be*
22 *submitted by a Market Participant that is itself a Load Serving Entity*
23 *(LSE) or is purchasing Energy to serve an LSE. (emphasis added).*

24 Part 4.3 Demand Bids of the BPM states (emphasis added):

25 *Demand Bids apply to the Day-Ahead Energy and Operating Reserve*
26 *Market only and represent a financially binding Bid to **purchase Energy***

1 *at Day-Ahead prices for Real-Time consumption in the next Operating*
2 *Day.* (emphasis added).

3 **Q. Does Ameren Missouri submit demand bids to the MISO?**

4 A. Yes. Ameren Missouri submits a Fixed Demand Bid to the MISO every
5 day for its entire forecasted demand – for all of the megawatt-hours it forecasts are
6 needed to serve its load – not just for the difference between its forecasted demand and
7 some projection of the amount of load it expects to have. As such, when Ameren
8 Missouri’s load clears in the Day Ahead market, it has a binding requirement to purchase
9 the entire sum of Energy that it bid for – to purchase ALL of the megawatt-hours, not just
10 some net amount.

11 **Q. Are there other BPM’s which demonstrate that load is purchased?**

12 A. Yes. Another MISO BPM is the Market Settlements Business Practices
13 Manual. Section 2.1.2 of this BPM is titled Settling and Invoicing the Financial
14 Transmission Right, Day-Ahead and Real-Time Energy and Operating Reserve Markets.
15 This section includes the following descriptions (emphasis added):

16 *Day-Ahead Energy and Operating Reserve Market Settlements – In the*
17 *settlement of the Day-Ahead Energy and Operating Reserve Market, each*
18 *MP that purchased energy is charged the Day-Ahead LMP applicable at*
19 *the relevant Commercial Pricing Node (CPNode) for the quantity (in*
20 *MWh) of energy scheduled and/or cleared.*

21 *Real-Time Energy and Operating Reserve Market Settlements – In the*
22 *settlement of the Real-Time Energy and Operating Reserve Market, each*
23 *MP is settled for Energy based upon the incremental difference between*
24 *its real-time energy transactions and its day-ahead scheduled energy*
25 *transactions multiplied by the applicable Real-Time LMP.* (emphasis
26 added).

27 **Q. Does Ameren Missouri receive settlement statements from the MISO?**

28 A. Yes.

1 **Q. What do these settlement statements show for the amounts purchased**
2 **from the MISO to serve load?**

3 A. The MISO settlement charge types which represent the amount of energy
4 purchased or sold to the MISO are Day-Ahead Asset Energy Amount and Real Time
5 Asset Energy Amount. Schedule JH-R2 to my testimony is a single day excerpt from a
6 MISO settlement report for day-ahead asset energy amount for both generation and load,
7 produced from nMarket, which is a software program used by Ameren Missouri in part to
8 track MISO settlement statements so that we can “shadow” settle their invoices.
9 nMarket imports data directly from the MISO settlement statement.

10 The asset owner UEGEN represents our generation, while asset owner UELSE
11 represents our load. As the report clearly shows, in each hour of the day, there is an
12 amount in the VAL column (which represents the settlement amount) for both the load
13 and the generation. The generation value is a credit for the revenue from the sale of
14 energy and the load value is a charge for the purchase of energy. If, as Mr. Dauphinais
15 would have the Commission believe, Ameren Missouri only sells energy whenever its
16 generation exceeds its load and only purchases energy when load exceeds its generation,
17 these settlement statements would only have a value in one or the other tabs in a given
18 hour, not both. But they have values for both generation and load in the same hour,
19 specifically because Ameren Missouri clears/purchases all of its load in each hour and
20 clears/sells all of its generation in each hour from the MISO market.

21 **Q. Doesn't the fact that Ameren Missouri takes Network Integration**
22 **Transmission Service (“NITS”) mean that it is simply transmitting its own**
23 **generation output to its own load?**

1 A. No. The various tariff provisions that I have already pointed out make it
2 clear that load serving entities, including Ameren Missouri, purchase the power for their
3 load from the MISO. Mr. Dauphinais appears to rest his argument on language found in
4 the preamble to part III of Module B (Network Integration Transmission Service) of the
5 EMT. The language in the preamble remains unchanged from versions of the tariff
6 which existed prior to the establishment of the MISO Day 2 energy market. The MISO
7 has simply failed to properly update this language to reflect the reality of its own market
8 and to conform to the specific provisions in the balance of the tariff which specify that
9 load is purchased from the market and generation is sold into the market (and which were
10 enacted after the establishment of the MISO market).

11 **Q. What portion of the preamble to part III of Module B of the EMT are**
12 **you referring to?**

13 A. I am specifically referring to the first paragraph which reads:

14 The Transmission Provider will provide Network Integration
15 Transmission Service pursuant to the applicable terms and conditions
16 contained in the Tariff and Service Agreement. Network Integration
17 Transmission Service allows the Network Customer to integrate,
18 economically dispatch and regulate its current and planned Network
19 Resources to serve its Network Load in a manner comparable to that in
20 which the Transmission Owners utilize the Transmission System to serve
21 their Native Load or other Network Customers. Network Integration
22 Transmission Service also may be used by the Network Customer to
23 deliver economy Energy purchases to its Network Load from non-
24 designated Resources on an as-available basis without additional charge.
25 Transmission Service for sales to non-designated Loads will be provided
26 pursuant to the applicable terms and conditions of Module B of this Tariff
27 and/or any applicable ITC Rate Schedule.

28 **Q. Why do you believe the preamble does not conform to the balance of**
29 **the EMT?**

1 A. First, the preamble states that NITS allows a Network Customer [e.g.,
2 Ameren Missouri] to economically dispatch its Network Resources [e.g., Ameren
3 Missouri's generation]. However, it is the *MISO* in its role as Transmission Provider and
4 Balancing Authority that dispatches the network resources in the MISO market. As such,
5 the preamble fails to reflect the operation of the market.

6 Secondly, while the preamble states that a Network Customer is allowed to
7 regulate its Network Resources to serve its Network Load, Schedule 3 (Regulating
8 Reserve) of the MISO tariff specifically states that "**(t)he MISO Balancing Authority**
9 **will procure this service on behalf of the Load Serving Entities** from cleared Resource
10 Offers submitted by Market Participants selected in the Energy and Operating Reserve
11 Markets, as provided for in Sections 39.2 and 40.2 of this Tariff. A Load Serving Entity
12 **must purchase this service** from the MISO Balancing Authority to satisfy its Regulating
13 Reserve Obligation, where such Obligation is defined below." (emphasis added). Again,
14 the more specific provisions of the EMT adopted when the MISO markets began
15 operation reflect what actually happens in the market, while the preamble does not.

16 Finally, as I've noted above, the preamble language fails to specifically
17 acknowledge the mechanics of the MISO market in regards to load and generation
18 clearing and settlements.

19 **Q. Do you have any other observations on the preamble language?**

20 A. Yes. It bears noting that the preamble, outdated as it is, does specifically
21 provide for the use of NITS to transport Energy purchases.

22 **Q. Please address Mr. Dauphinais' contention that transmission**
23 **revenues should be removed from the FAC.**

1 A. As Ameren Missouri witness Lynn Barnes indicates in her rebuttal
2 testimony, in our last rate case we recommended that transmission revenues be included
3 in the FAC. This was consistent with the treatment the Staff had recommended for
4 Kansas City Power & Light – Greater Missouri Operations Company ("KCPL-GMO")
5 when a transmission tracker was being discussed in an earlier KCPL-GMO rate case (the
6 Staff supported the tracker in that case, but only as long as transmission revenues were
7 included). We agreed that transmission revenues should be included in the mechanism
8 where transmission costs are included, in our case, in the FAC, although in earlier years
9 the transmission revenues had not changed much so the impact to customers of including
10 or excluding them had been small relative to our total revenue requirement. We continue
11 to think that it makes sense for the revenues to be included in the FAC, as are the costs.

12 **B. Volatility and Uncertainty of FAC Components.**

13 **Q. OPC witness Lena Mantle recommends that the FAC be discontinued,**
14 **contending, in part, that Ameren Missouri has failed to demonstrate that the**
15 **various cost components are volatile. Are the various cost components of the FAC**
16 **indeed volatile and uncertain?**

17 A. Yes. Cost is a function of both price and volume. As a result, even for
18 those components such as coal where we may have relative price certainty for the near
19 term, volatility and uncertainty regarding the volume remains, as discussed in the rebuttal
20 testimony of Ms. Barnes and Company witness Jeffrey S. Jones. Ms. Mantle would
21 seemingly have the Commission ignore the volumetric piece of the equation as she has
22 focused only on the question of price certainty.

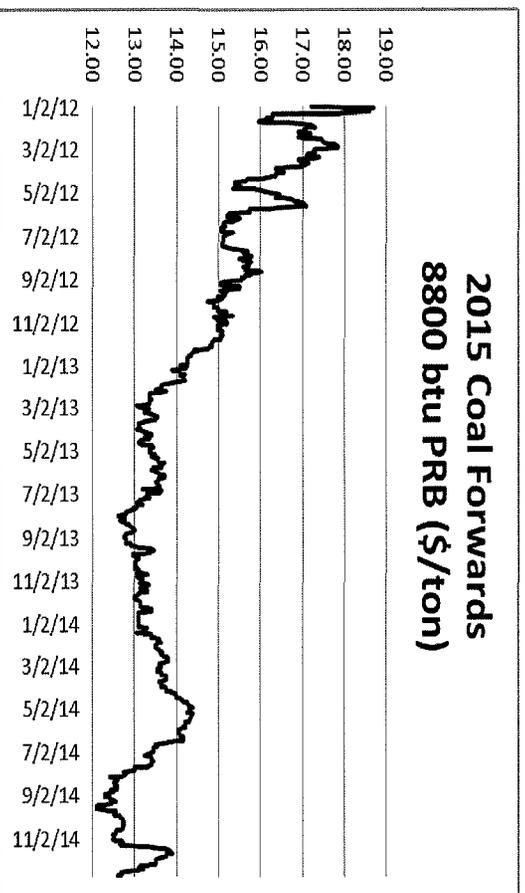
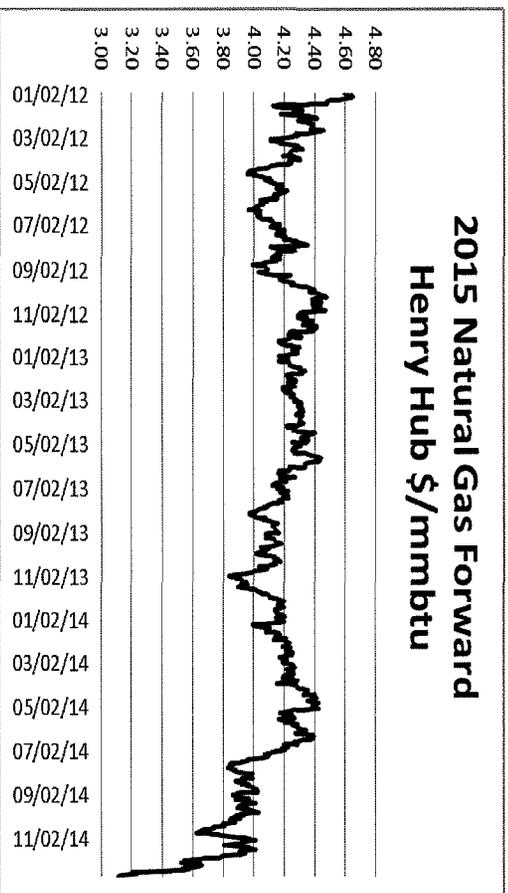
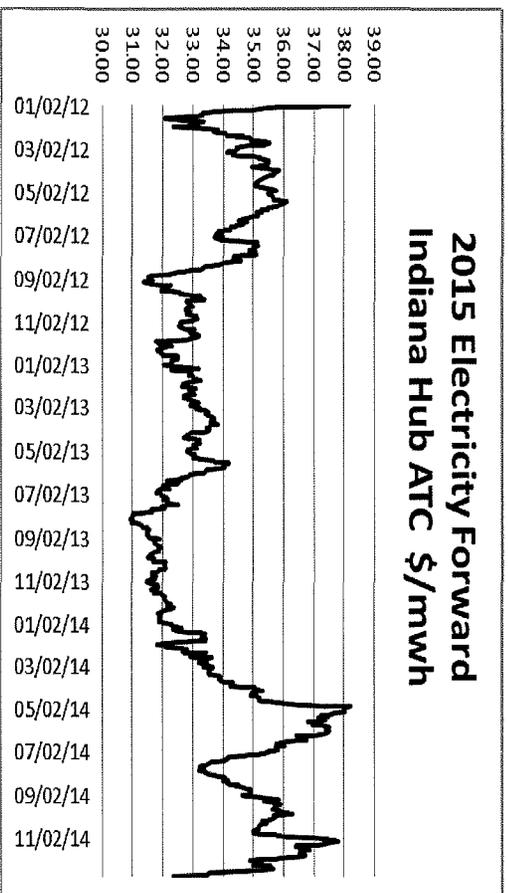
23 The market price for energy remains volatile and is expected to remain so for
24 quite some time. While natural gas fracking and increased installations of wind and other

1 renewable resources have applied downward pressure on electrical energy prices
2 (particularly in the off-peak periods), actual and projected retirement announcements for
3 coal-fired resources resulting from environmental regulations have an opposite and much
4 less certain impact. I am not aware of any party to this proceeding that is arguing that
5 these wholesale market energy prices are not volatile.

6 Natural gas prices, while currently lower than in recent years, continue to display
7 volatility. It was reported in December that the State of New York has banned fracking.
8 While I am not suggesting that this means that fracking will be banned nationwide, it
9 does highlight the uncertainty that exists regarding what natural gas prices will be in the
10 future. When we consider the dramatic downward movement that we have experienced
11 as a result of the fracking revolution, it is not too difficult to imagine what the impact
12 would be if more jurisdictions were to ban the technology.

13 Additionally, the price of coal remains volatile. While Ameren Missouri does
14 indeed have long-term contracts for coal purchases in place, it must be recognized that
15 the dispatch cost of our coal-fired units is based on the spot price of coal, not the
16 accounting cost. As a result, fluctuations in the price of coal affect our unit dispatch –
17 again, affecting the volume of coal that is consumed.

18 I have prepared three simple graphs that show that prices for these three
19 commodities remain volatile and uncertain. Each of these represents the calendar year
20 forward contract for 2015, over the past three years.



1 Market energy and fuel prices all impact the dispatch of Ameren Missouri's
2 generators.¹⁶ If market energy prices rise faster than increases in the market price of the
3 coal or natural gas fuel burned by the generator, we would expect to see the volume of
4 generation output increase. If market prices rise slower than the rate of increases in the
5 market price of the coal or natural gas fuel input for a generator, we would expect to see
6 the volume of generation output decrease. Of particular interest to this discussion is the
7 impact of wind resources on the prices available to base load, coal-fired generation in the
8 overnight hours. The lowering of off-peak prices frequently results in having such
9 generators dispatched near unit minimums.

10 Looking at total output and coal cost for our coal-fired generators from 2010
11 through 2014, we can see very large differences between the years. The change from
12 2011 to 2012 alone was 14%, and the increase in coal cost from 2012 to 2013 was 11%.
13 While the year-on-year changes in the other years may not have been as dramatic, they
14 should not be dismissed as insignificant. As the table below shows, the lowest year-on-
15 year change in coal cost at the coal-fired units was over \$31 million. In just the five
16 years included in the table below, we have seen volume changes between 2% and
17 negative 14% and cost changes between 11% and negative 5%.

	MWH	\$	Mwh Change	%	\$ Change	%
2014 **	33,059,731	\$736,337,348	(269,970)	-1%	\$33,939,648	5%
2013	33,329,701	\$702,397,700	907,887	3%	\$67,187,949	11%
2012	32,421,814	\$635,209,751	(5,083,114)	-14%	(\$34,567,345)	-5%
2011	37,504,928	\$669,777,096	606,646	2%	\$31,190,538	5%
2010	36,898,282	\$638,586,558				

**Includes preliminary values for December 2014.

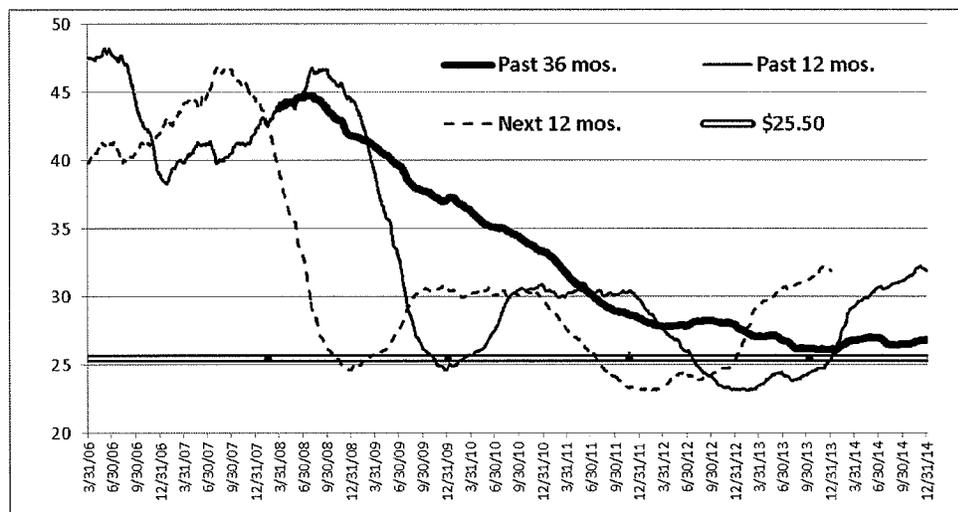
¹⁶ While the actual, contracted-for price for the coal we buy determines our delivered coal costs, it is the market price of coal that determines the dispatch of our units.

1 **Q. Are there other cost components of the FAC which also demonstrate**
2 **volatility?**

3 A. Yes. In particular, I would note the high degree of volatility in
4 transmission charges associated with Schedule 26A of the MISO tariff discussed above,
5 and the coal commodity and transportation costs discussed in the rebuttal testimony of
6 Ameren Missouri witness Jeffrey S. Jones.

7 **Q. Your market price for energy chart above illustrates the variability in**
8 **forward prices. Do historical prices also show variability?**

9 A. Yes. The following graph of the average LMP for our coal-fired
10 generators illustrates that both the rolling one year and three-year historical average day
11 ahead LMP have varied greatly over the past seven years, and are currently rising from
12 their lowest values over this same period.



13 **Q. The graph also includes a line labeled “Next 12 mos.” What does this**
14 **line represent?**

1 A. This line illustrates that it is an extremely rare occurrence that the actual
2 price available to our generators in any given 12-month period is equal to (or even close
3 to) the average price for the three preceding years, at a given point in time.

4 **Q. Does this indicate that a three-year historical period to develop**
5 **normalized prices should not be used to set the off-system sales component of the**
6 **NBEC?**

7 A. No, it does not. As I stated in my rebuttal testimony in File No.
8 ER-2012-0166, we absolutely have to set a base level of NBEC, and rebasing with more
9 current data than we had when NBEC were last rebased is appropriate, as all parties and
10 the Commission have recognized. However, given the inherent uncertainty in the level of
11 future power prices that supported the establishment of the FAC in the first place, it is
12 simply unreasonable to expect any method to consistently and reliably predict what those
13 future prices will be. I continue to believe the methodology which has been used over the
14 past several cases by all parties who take an interest in off-system sales (essentially the
15 Company, the Staff, and MIEC) is reasonable, and its continued use makes sense. The
16 three-year average, by its very nature, will have less variability than shorter term periods.
17 I am still not aware of any evidence or proposal made by parties to the prior case which
18 would consistently result in a more accurate baseline.

19 **Q. What is the significance of the line labeled \$25.50?**

20 A. \$25.50 is the normalized “around-the-clock” energy price that has been
21 calculated for the true-up period. This amount was calculated using three years of actual
22 historical generation weighted day ahead LMPs and adjusted to account for the Polar
23 Vortex anomaly.

1 **Q. How does this value compare to the value calculated for the true-up**
2 **period in the prior rate case?**

3 A. The equivalent value in the last rate case was \$28.12.

4 **Q. Does this conclude your rebuttal testimony?**

5 A. Yes, it does.

DEFINITIONS

Day Ahead Energy and Operating Reserve Market: The forward market for purchases and sales of Energy and Operating Reserve conducted by the Transmission Provider the Day prior to the Operating Day.

Energy Offer: The price at which a Market Participant has agreed to sell the next increment of Energy from a Generation Resource, Demand Response Resource – Type I, Demand Response Resource-Type II or the price at which a Market Participant has agreed to sell Energy via a Dispatchable Interchange Schedule Import Schedule; or the price at which a Market Participant has agreed either to import or export the next increment of Energy from an External Asynchronous Resource.

Fixed Demand Bid: A request to purchase a specified MWh quantity of Energy, at specified locations in the Transmission Provider Region, during specific Hours of the next Operating Day submitted to the Day-Ahead Energy and Operating Reserve Market. Demand Bids may only be submitted by a Market Participant that is itself a Load Serving Entity (LSE) or is purchasing Energy to serve an LSE.

Generation Offer: An Energy Offer, Start-Up Offer, No-Load Offer, Regulating Capacity Offer and Regulating Mileage Offer (if a Regulation Qualified Resource), Spinning Reserve Offer (if a Spin Qualified Resource) an On Line Supplemental Reserve Offer (if not a Spin Qualified Resource) and Off Line Supplemental Reserve Offer (if a Quick Start Resource) submitted by a Market Participant within the MISO Balancing Authority Area for the output of a specified Generation Resource to supply Energy and/or Operating Reserve to the Energy and Operating Reserve Market.

Offer: An offer, that is duly submitted to the Transmission Provider consistent with this Tariff and the Business Practices Manuals, to (a) sell Energy and Operating Reserve in the Energy and Operating Reserve Markets at a specified price, location, quantity, and time period and shall include (i) Generation Offers, (ii) Demand Response Resource-Type I Offers, (iii) Demand Response Resource-Type II Offers, (iv) External Asynchronous Resource Offers, (v) Stored Energy Resource Offers and (vi) Dispatchable Interchange Schedule Import Schedules and (b) purchase Energy through Fixed Interchange Schedule Import Schedules and Dynamic Interchange Schedule Import Schedules at a specified location, quantity, and time period.

Real-Time Energy Purchases: For a Market Participant, a value in MWh equal to the sum of the following, as applicable:

- (i) For Load Zones, the maximum of (a) the difference between (1) Actual Energy Withdrawals (net of Real-Time Financial Schedules) and (2) Day-Ahead Schedules for Energy or (b) zero (0);
- (ii) for Resources, the maximum of (a) the difference between (1) Day-Ahead Schedules for Energy or (2) Actual Energy Injections (net of Real-Time Financial Schedules) or (b) zero (0);
- (iii) for Virtual Transactions, the Day-Ahead Schedule resulting from a cleared Virtual Supply Offer;
- (iv) for Import Schedules, the maximum of (a) the difference between (1) the Day-Ahead Import Schedule and (2) the Real-Time Import Schedule and (b) zero (0);
- (v) for Export Schedules, the maximum of (a) the difference between (1) the Real-Time Export Schedule and (2) the Day-Ahead Export Schedule and (b) zero (0); and

(vi) for Real-Time Financial Schedules without any associated Actual Energy Injections or Actual Energy Withdrawals pursuant to Section 40.3.3.a.xvii(i) and 40.3.3.a.xvii(ii), the volume associated with the seller side of the Real-Time Financial Schedule.

Real-Time Energy and Operating Reserve Market: The Market for purchases and sales of Energy and Operating Reserve conducted by the Transmission Provider during the Operating Day.

