BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

UNION ELECTRIC COMPANY D/B/A AMEREN MISSOURI'S APPLICATION FOR REHEARING AND RECONSIDERATION

COMES NOW Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or the "Company") and, pursuant to § 386.500.1, RSMo.,[1] and 4 CSR 240-2.160, respectfully applies for rehearing of the Commission's Report and Order in the above-captioned proceeding which was issued April 29, 2015 ("Report and Order"), and for its Application for Rehearing and Reconsideration states as follows:

1. Commission decisions must be lawful (i.e., the Commission must have statutory authority to do what it did) and must be reasonable. *State ex rel. Atmos Energy Corp. v. Pub. Serv. Comm'n*, 103 S.W.3d 753, 759 (Mo. banc 2003); *State ex rel. Alma Tele. Co. v. Pub. Serv. Comm'n*, 40 S.W.3d 381, 387-88 (Mo. App. W.D. 2001). The decision is reasonable only if supported by competent and substantial evidence of record. *Alma*, 40 S.W.3d at 388. Moreover, Commission decisions must not be arbitrary, capricious, or unreasonable. § 536.140.1(6). The Commission is a creature of statute and it has only the powers conferred on it by the Legislature. *State ex rel. City of St. Louis v. Pub. Serv. Comm'n*, 73 S.W.2d 393, 399 (Mo. banc 1934).

2. A review of the evidentiary record in this case and applicable law demonstrates that the Report and Order fails to comply with the above-referenced legal principles respecting the Commission's determination of three issues, as follows: the Commission's decisions regarding (a) the treatment of transmission charges; (b) the establishment of billing units for

[1] Statutory references are the Missouri Revised Statutes (2000), unless otherwise noted.

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ratemaking purposes associated with the Large Transmission Service rate class[2] (i.e., for Noranda Aluminum, Inc. ("Noranda")); and (c) the rate subsidy provided to Noranda. While the Commission's decision regarding return on equity ("ROE") may not constitute error as a matter of law, for the reasons outlined below, the Company also requests that the Commission reconsider its decision regarding ROE.

APPLICATION FOR REHEARING

A. Transmission Charges

3. Ameren Missouri respectfully requests that the Commission grant rehearing on its decision to change the Company's fuel adjustment clause ("FAC") to exclude Midcontinent Independent System Operator, Inc. ("MISO") transmission costs and revenues. There are important legal and policy reasons that MISO transmission costs should remain in the FAC. First, as a legal matter, these costs constitute transportation costs for purchased power, which are authorized for inclusion in an FAC under § 386.266 (1), as we discuss in detail below. As we explain in detail there, there is no legal impediment to including transmission charges in the FAC, as the Commission has done since the inception of Ameren Missouri's FAC. Second, MISO transmission costs are large, volatile and beyond Ameren Missouri's ability to control, which are the standards the Commission generally applies in deciding which costs to include in an FAC. Indeed, the Commission specifically found that this was the case in the Company's last rate case order, as discussed below. Nothing has changed since then. Third, MISO transmission costs are an unavoidable consequence of Ameren Missouri's participation in the MISO market where Ameren Missouri realizes significant benefits that are reflected in the FAC for the benefit of its customers. Because of these significant benefits, it is only appropriate and fair that the transmission charges assessed on Ameren Missouri for all of the power it purchases from the MISO market also be included in the FAC. Fourth, reversing course now, after having included these transmission charges in the FAC since its inception reflects an inconsistency in regulation that investors will have a very difficult

[2] And for the Industrial Aluminum Smelter Service rate class.

time understanding and accepting. While one Commission cannot bind another, utilities and their investors need some reasonable level of certainty about the treatment of costs and revenues in the ratemaking process. Finally, excluding these costs from the FAC substantially increases the odds that Ameren Missouri's rates will not allow it to cover its cost of service in future years and may deprive Ameren Missouri of a reasonable opportunity to earn a fair ROE. While the amount of the increases cannot be calculated with certainty because it depends in substantial part on the costs actually incurred for the billions of dollars of regional transmission lines that are to be constructed,[3] there is little doubt that the year-over-year increases will be very large, as the record in this case shows[4]:

[redacted]

[3] The Commission has recognized the uncertainty and volatility in these charges: "MISO transmission charges are volatile because no one knows for sure how much those MVP projects will costs once construction is complete." *Report and Order*, File No. ER-2012-0166, p. 88, ¶17.

[4] Ex. 14 (Haro Rebuttal), p. 20. While there may be some increase in MISO transmission charges other than those arising under MISO Schedule 26A, the vast majority of the increases will likely be in 26A transmission charges. We would also note that as the Commission previously recognized, these increases are estimates because it is not known what the billions of dollars of regional transmission construction that will generate the transmission charges will ultimately cost to build. It is clear, however, that the transmission charges will be very substantial and will also increase substantially year-over-year.

While just the year-over-year changes shown above are very substantial, the cumulative effect of these year-over-year increases (assuming rate cases are not filed) is even greater, as the following chart shows:[5]

[redacted]

Moreover, even if the Company changed its rates every other year, the cumulative effect is still extremely large and the Company would still lose tens of millions of dollars, as the following chart shows:

[5] This chart and the next one use date from the above-table.

[redacted]

4. Given the magnitude of the expected increases and the inability to cover them through base rates, coupled with the revenue requirement associated with investment in the Company's system and ordinary cost increases (such as annual wage increases embedded in collective bargaining agreements), the odds of the Company coming in for larger and more frequent rate cases is greatly increased if the Commission removes these transmission charges from the Company's FAC. Moreover, as the second chart above shows, the funds necessary to cover these substantial year-over-year increases in transmission charges simply cannot be recovered even if the Company files frequent rate cases.[6] This means that funds that would otherwise have been available for investments in the Company's generation and energy delivery systems will have to be diverted to cover these increasing, uncontrollable costs. It is important to

[6] The Company has worked hard to attempt to reduce the frequency of its rate cases, and was able to delay filing a rate case for about 30 months between its 2012 and 2014 rate cases. It had hoped to stay out longer after this rate case, but being forced to absorb these kinds of increases will make that extremely difficult, if not impossible.

note that the Company is not in a position to simply "find" these funds elsewhere. Since the true-up cutoff date in the Company' last rate case (File No. ER-2012-0166), the Company has reduced its operations and maintenance costs by almost $90 million annually,[7] even while experiencing normal wage increases and other contracted-for increases in costs that it cannot avoid. Finding this level of savings was extremely difficult, and it will be even more difficult to reduce costs in the future without impacting the performance of the Company's generation and energy delivery systems. Moreover, load growth is very low, or non-existent. The Company does not have levers available to it to simply absorb transmission charge increases of this magnitude, nor should it be required to do so.

5. In addition to the foregoing, an examination of the reasoning underlying the Commission's decision on transmission charges reveals that the Commission was mistaken in a number of important respects, and that there is no legal bar to including these transmission charges in the FAC.

6. The heart of the Commission's decision to reverse the treatment of transmission charges, a treatment that has been in place from the very first day of the operation of Ameren Missouri's FAC, lies in the Commission's conclusion of law (for which no support is cited) that the "drafters of the FAC statute likely did not envision a situation where a utility would consider all its generation purchased power or off-system sales."[8] The Commission then goes on to express its legal opinion that "[a]t the time the statute was drafted, and even in our more complex present-day system, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are

[7] These are non-energy related and non-tracked costs, e.g., these do not include changes in costs such as pension and OPEB costs, which are included in trackers.
[8] *Report and Order*, p. 115.

unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified."[9] Finally, the Commission expresses the additional legal opinion that including the transmission charges (other than those associated with what the Commission characterized as "true purchased power") would "expand the reach of the FAC beyond its intent."[10] Taken together, the forgoing legal conclusions reflect an incorrect understanding of the circumstances existing when S.B. 179[11] was enacted, as we explain in detail below. Indeed, the existence of and operation of regional transmission organization ("RTO") markets and in particular the MISO energy markets *were* the "present-day system" when S.B. 179 was proposed and ultimately adopted. The Report and Order suggests that the Commission mistakenly believed that RTO markets did not exist at the time, and that the Legislature did not understand that not only did they exist, but Ameren Missouri was – when the S.B. 179 was enacted – selling all of the power it generated to the MISO market and buying all of the power it then sold to its load from the MISO market, as we explain in more detail below.

7. The Report and Order also reflects certain mistaken facts. It is entirely undisputed that the MISO tariff reflects (and since the inception of MISO's energy markets, has always reflected) the reality that a market participant like Ameren Missouri indeed sells all of the megawatt-hours ("MWhs") produced by its generators to the MISO's energy market, at certain nodes and prices, and then separately buys all of the MWhs it needs to sell to its customers (its load) at a different node and at a different price.[12] To the extent the Report and Order conflates

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[9] *Id.*
[10] *Id.* at p. 116.
[11] L. 2005 S.B. 179, passed April 27, 2005 and signed by the Governor on July 14, 2005. As the Commission knows, S.B. 179 enacted section 386.266, RSMo. (Cum. Supp. 2014), which authorizes FACs in Missouri.
[12] Ex. 14, p. 24, l. 6 to p. 27, l. 20. Missouri Industrial Energy Consumers witness James Dauphinais made no attempt to rebut any of this evidence.

these two separate transactions into a "buy back" of power,[13] with the suggestion apparently being that Ameren Missouri hands its widgets to MISO and then gets those same widgets back at the same location and price, it is mistaken. The record shows otherwise.[14] To the contrary, the evidence shows that the MISO market is like a large pool of water. No market participant that both sells to the pool and buys from it can be said to have bought back its own power because its "own power" cannot be identified as such. This is made even clearer by the fact that the sale and the purchase occurs at different locations and at different prices. Ameren Missouri buys all of the power it then sells to its customers from the MISO market and that power is not its own power – it can't be. Consequently, the facts are that Ameren Missouri *has* purchased that power. The conclusion that the power purchased to serve Ameren Missouri's customers is "self-generated" overlooks this. Indeed, it appears that the Report and Order rests on the premise that Ameren Missouri "self-supplies" its load. The record supports no such conclusion, and indeed refutes it. Ameren Missouri does not "self-supply" the energy it produces.[15] As Ameren Missouri witness Jaime Haro explained to Chairman Kenney in response to his questions, "self-supply" is not even defined in the MISO tariff.[16] Moreover, when self-supply does come into play, it relates to resource adequacy (i.e., capacity, not energy) or to station service (only the energy consumed by the generation plant itself).[17]

8. The Commission similarly misapplies FERC[18] Order 668 by finding as a matter of fact that FERC Order 668 means "that for accounting purposes, Ameren Missouri is required to

[13] "Power" and "energy" are synonymous.
[14] *Report and Order*, p. 112, Finding of Fact No. 4. A "purchase back" implies that the Company buys back the same power it sold. It does not, and Mr. Haro did not testify that it did, notwithstanding the Commission's citation to Mr. Haro's testimony in footnote 291 of the *Report and Order*.
[15] Tr. p. 2058, l. 4-8.
[16] Tr. p. 2039, l. 10 to p. 2040, l. 4.
[17] Tr. p. 2042, l. 5 to p. 2044, l. 9.
[18] Federal Energy Regulatory Commission.

recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power."[19] The terms of FERC Order 668 show that this is incorrect.

9. FERC Order 668 states that companies like Ameren Missouri make *gross* purchases of energy from RTO energy markets: The "***gross*** sale and ***purchase*** transactions that support the net energy market amounts recorded on their books"[20]; "we clarify that the netting of purchases and sales in an RTO energy market is appropriate not only for transactions where participants are required to bid their generation into the market ***and buy generation from the market to supply their native load***, but also in cases where an RTO offers an energy market in which participants may choose to offer all generation to and ***buy all power from the energy market***"[21] (emphasis added). *Power is purchased.* The only reasonable conclusion that can be drawn is that we are dealing with "purchased power." If purchased power is involved, and if the transmission charges are assessed on that purchased power, then clearly the transmission charges are for the transportation of purchased power within the meaning of § 386.266.

10. Moreover, just because the dollars received for the sale of power and the dollars paid for the separate power that is purchased are netted when invoices are sent and when reports are prepared[22] does not mean that Ameren Missouri is being "required to recognize" that there are three categories for power; i.e., off-system sales, "self-generated" power and the "true" purchased power the Commission references in the Report and Order. Nowhere does FERC Order 668 create a category of "true" purchased power as opposed to "false" purchased power, nor does it create a category of "self-generated" power. These are terms that appear nowhere in

[19] *Report and Order*, p.113, ¶ 7.
[20] Ex. 66, p. 39, ¶ 80.
[21] *Id.*, p. 39 to p. 40, ¶ 82.
[22] While invoices net the dollars, MISO's settlement statements clearly reflect both the separate sale of the gross MWhs of energy sold and the separate purchase of the gross MWhs purchased. Ex. 14, p. 26, l. 11 to p. 27, l. 20, and Schedule JH-R2.

any FERC order or utility account and they do not reflect what actually happens. The Company is not simply calling the power it purchases "purchased power." Instead, the facts are that *it is* purchased, as the MISO's tariff and FERC Order 668 fully recognize.

11. The foregoing brings us back to the mistaken "conclusions of law" noted in ¶ 6 above, which it appears reflects the Commission's belief there is a legal bar to including these transmission charges in the FAC. But understanding the facts, and properly applying the law to those facts, shows that there is no such bar. There is no question: the guiding principle of statutory interpretation is to determine the intention of the Legislature. *See, e.g., Hessel v. Missouri Dept. of Social Services*, 400 S.W.3d 813, 817 (Mo. App. E.D. 2013). Moreover, statutory interpretation is purely a question of law, meaning the Court of Appeals will review any Commission interpretation *de* novo. *See, e.g., State v. Carroll*, 165 S.W.3d 597, 602 (Mo. App. S.D. 2005). The Company agrees with the Commission that a relevant question is what did the Legislature intend when it used the terms "purchased" and "power"? To find out, and since those terms are not defined in § 386.266, we look to the plain meaning of those terms, as found in the dictionary. *Hessel*, 400 S.W.3d at 817. The dictionary tells us that "purchase" and "acquire" are synonyms.[23] The dictionary also tells us that to "purchase" is to "obtain by paying money or its equivalent."[24] The Commission itself has recognized that Ameren Missouri acquires all of the power it sells to its customers from the MISO market.[25] Moreover, there is also no question but that MISO owes Ameren Missouri money for the MWhs Ameren Missouri sells and Ameren Missouri owes MISO money for the MWhs Ameren Missouri buys. MISO could cut Ameren Missouri a check for the gross dollars it owes Ameren Missouri, and Ameren Missouri could cut MISO a check for the gross dollars it owes MISO, but instead the dollars are

[23] *Merriam Webster's Collegiate Dictionary*.
[24] *Id.*
[25] *Report and Order*, File No. ER-2012-0166, p. 83.

netted. However, the fact that separate checks are not literally cut does not mean there is not a sale nor does it mean there is not a purchase. Not only is there no dispute about the foregoing, but there is no dispute but that the commodity we are dealing with is electrical energy – power. Despite the plain meaning of the words the Legislature used, the Report and Order concludes they mean something else. We respectfully submit that this was error, because it amounts to the Commission re-writing § 386.266.

12. Perhaps the Commission ignores the plain meaning of "purchased" and "power" under the belief that the terms are ambiguous and thus require construction. The Commission's policy discussion, however, actually undermines any such conclusion.

13. The Commission points to § 386.266, which it says sets a policy to insulate the utility from "uncontrollable fluctuations" in transportation costs of purchased power. Referencing that policy, the Report and Order then concludes that only the costs of transporting any net amount of energy that would be above the quantity of energy that the utility sold (separately) to the market would be outside the utility's control. However, this is incorrect because it assumes that Ameren Missouri can control transmission charges associated with a particular quantity of power (a quantity equal to that which it sells to the market). In fact, Ameren Missouri lacks control over *all* of the transmission charges it incurs from MISO.

14. Why? Because Ameren Missouri gets a bill from MISO for transmission charges assessed on *every single* MWh its customers consume. Ameren Missouri cannot control these transmission charges nor can it know what the transmission charges will be. Those transmission charges arise (in large part) from multi-value projects that MISO is requiring to be built throughout its footprint and which, under MISO's tariff, create transmission charges that Ameren Missouri is required to pay. If a policy reflected in § 386.266 is to allow utilities to include

transportation costs in the FAC when those transportation costs are beyond the utility's control – and the Report and Order says that is the policy reflected in the statute (and we agree) – then the Report and Order should not prevent Ameren Missouri from reflecting these uncontrollable transportation charges in the FAC because keeping them out of the FAC is contrary to the policy embodied in the statute. Indeed, the Commission itself has already recognized in previous orders that Ameren Missouri cannot control these costs and that the costs are uncertain. "Those costs [the *same* ones at issue here] meet the Commission's past standards for inclusion in the fuel adjustment clause in that they are significant in amount, volatile in that they are not only rapidly rising, but are also uncertain in amount, and they are largely beyond the control of Ameren Missouri. The Commission finds that MISO transmission costs should continue to be flowed through Ameren Missouri's fuel adjustment clause."[26] Nothing has changed since that previous order. The Commission is right: the "statute is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power."[27] But the Commission, while right about the policy, has reached a conclusion which directly undermines that policy and consequently undermines what the Legislature was trying to do when it included transportation of purchased power costs in the FAC statute.

15. This brings us to what amounts to a misunderstanding reflected in the Report and Order: that the Legislature would not have envisioned the circumstances we have here, where a utility does buy all of the power it uses to serve its load from an RTO market. The facts indicate that in fact the Legislature did envision precisely the circumstances we have here.

16. The FERC approved MISO's Transmission and Energy Markets Tariff on August 6, 2004 – five months before § 386.266 was proposed, and almost eight months before it was

[26] *Report and Order*, File No. ER-2012-0166, pp. 88-89, ¶ 19.
[27] *Report and Order*, p. 115.

passed. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (Aug. 6, 2004), *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005), *reh'g denied*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007).[28] Under the August 6, 2004 FERC order, MISO's energy markets were approved and set to begin operation on April 1, 2005, and they did.[29] FERC tariffs have the force and effect of law. *Central Iowa Power Coop. v. Midwest Independent Transmission System Operator, Inc. et al.*, 561 F.3d 904, 913 (8th Cir. 2009). There is absolutely no question but that a tariff having the force and effect of law had already been approved well *before* S.B. 179 was ever introduced,[30] and indeed that the energy markets that are at issue here began to operate *nearly a month* before S.B.179 was passed. And in all material respects, those energy markets (the day-ahead and real-time markets) operate today as they operated then. It is certainly undisputed that Ameren Missouri sold all of the MWhs it generated to the MISO market starting April 1, 2005, and that it bought power from the MISO market to serve its load, also starting on April 1, 2005, just as it does now.

17. It is presumed that the Legislature, when enacting statutes, has knowledge of the subject matter and surrounding circumstances. *See, e.g., State ex rel. Safety Proofing Systems, Inc. v. Crawford,* 86 S.W.3d 488, 492 (Mo. App. S.D. 2002). Moreover, it is presumed that the Legislature knew the law at the time it enacted the legislation. *See, e.g., Id.; White v. American Republic Ins. Co.*, 799 S.W.2d 183, 189 (Mo. App. S.D. 1990). Consequently, the Legislature

[28] The appeal that resulted in the *Wis. Pub. Power* decision did not involve any issues about the basic operation of the energy markets at issue here.
[29] Subsequent orders on rehearing made some modifications to the original tariff, but the basic operation of the energy markets which continues today, was unchanged. *See, e.g., Order on Reh'g*, 109 FERC ¶ 61,157 (Nov. 8, 2004) (Where the FERC rejected any fundamental changes to the energy markets, stating that "We believe that the Midwest ISO and market participants need certainty as to the market rules that will be in place at the start of the market so the Midwest ISO can administer the market and participants can hedge their transactions, based on known rules.").
[30] It was introduced on January 13, 2005.

knew that the largest electric utility in the state was a participant in an RTO, knew that a FERC-approved energy markets tariff where participating utilities bought all of the power they needed to serve load had been approved to take effect on April 1, 2005 and knew, before the bill was passed, that indeed those markets were in actual operation because RTOs (including MISO) existed, and there existed a FERC-approved tariff (which as noted earlier reflects the law) that said so. Moreover, Ameren Missouri was buying and selling power in that market. The Legislature is deemed as a matter of law to have known *all* of these circumstances. Thus, the Report and Order is incorrect about what the Legislature could or could not have envisioned. Indeed, the Legislature did envision that transportation of purchased power could include transmission charges from MISO to Ameren Missouri for the power that Ameren Missouri buys from the MISO market and did so as a matter of law because those were the facts existing at the time.

18. What this means is that the Report and Order is premised on a view that the Legislature did not understand the undisputed reality that utilities in RTOs *purchase* all of the *power* they then sell to their customers from the RTO markets, apparently leading the Commission to a view that it could not include these charges in the FAC. In addition, it is premised on the view that the Legislature did not understand that those same RTOs assess transportation charges on the purchase of that power from the RTO market and on a view that at the time § 386.266 was enacted the Legislature had in mind a less "complex" system as opposed to the "present-day" system."[31] However, the "present-day" system *is* the system that was in place when the statute was proposed and adopted. This shows there is no bar to including these transmission charges in the FAC; in fact, the Legislature contemplated these circumstances, showing that the Legislature did intend the transmission charges to be included as costs of

[31] *Report and Order*, p. 115.

transporting purchased power. And as noted, the Report and Order is also incorrect when it concludes that Ameren Missouri can control these transportation charges, or that they are certain, even though the Commission found just the opposite in File No. ER-2012-0166. *Nothing whatsoever* has changed that justifies a reversal of those findings here.

19. The foregoing demonstrates that the Commission's decision regarding transmission charges is contrary to law because the Commission has effectively rewritten § 386.266 and in doing so it has incorrectly concluded that there is some bar to including these transmission charges in the FAC, when there is none. This is shown by (a) the plain meaning of the terms "purchased" and "power" and (b) by the facts showing that the Legislature did envision the reality of the operation of RTO markets that makes the power Ameren Missouri acquires from the MISO market to serve its load purchased power, and thus makes these transmission charges transportation associated with that purchased power.

20. The Commission's transmission charges decision is also unreasonable because it is contrary to (and not supported by) the competent and substantial evidence of record and is arbitrary and capricious. There is no evidence that Ameren Missouri can control any of the transmission charges at issue; indeed, the evidence is contrary. The evidence does not support the conclusion that the transmission charges at issue are certain; the evidence is contrary. As noted earlier, the evidence does not support the claim that Ameren Missouri sells its customers "self-generated" power; it is undisputed: all power generated is sold to the MISO market (at a different location and price than power it buys from the market) and Ameren Missouri does not "self-supply" its power.

21. Finally, as previously stated, there are important policy considerations that indicate that continuing to include transmission costs and revenues in the FAC is in the long-

term best interests of Ameren Missouri, its customers and the state. Including these costs and revenues in the FAC will give Ameren Missouri a real opportunity to cover its cost of service, as these uncontrollable costs escalate in the future; and it will better enable Ameren Missouri to make investments in its system to ensure long-term reliability for the benefit of its customers.

22. For all of these reasons, the Commission should grant rehearing on the transmission charges issue and, as it has previously done, allow differences in these costs to be recovered or refunded through the FAC.

B. Noranda Load

23. The Commission's decision not to normalize Noranda's load is unreasonable because it is not supported by competent and substantial evidence of record, is contrary to the evidentiary record in this case and is arbitrary and capricious.

24. Aside from a severe weather-related impact (like the 2009 ice storm) or pot failures (starting in 2014 and which remained unresolved even as of the time the record in this case closed), it is beyond debate that Noranda does not, on average, operate at a 98% load factor.[32] This fact is undisputed in the record before the Commission. In 2005, 2010 and 2012 Noranda's load factor was only 97.0%, 95.7% and 97.3%, respectively. In 2014, it was only 95.4%.[33] Would it have been higher in 2014 without the pot failures? Probably, but whether that is true entirely misses the point. Cost of service items should be normalized if they fluctuate such that over time, when rates are in effect, the discrete test year value will likely be unrepresentative of what actually will happen. How can the Commission possibly conclude that the 98.2% load for the test year does not fluctuate and that it will be representative of Noranda's load when rates are in effect given the undisputed history of load fluctuations, including several

[32] The Commission used a 98.2% load factor for purposes of ruling on this issue in the Report and Order.
[33] The foregoing figures appear in Exhibit 53 (Wills Rebuttal) and 54 (Wills Surrebuttal).

years with load materially less than 98.2%?[34] Using a three-year average of actual load, as is commonly done, the load factor should have been 97%. At Noranda's $36 per MWh base rate, assuming a load factor of 98.2% overstates Noranda's likely revenues and lowers the Company's revenue requirement by $1.6 million.

25. Instead of normalizing the load, as it should have done, the Commission ignored the evidence and concluded that Noranda will fix the pots (presumably by May 30th of this year) and then jump back up to 98.2% *and stay there*. On what basis? Respectfully, there is none. History says otherwise, because Noranda has not stayed at a 98.2% load factor. Various occurrences cause drops in that load factor, which is why it should be normalized. Even more pertinent here is that despite promise after promise that it would return to "full" load, Noranda, as of the moment this application is filed, is still far below 98.2% or even 97%. In fact, as of just last week Noranda's load stood at less than *90%*, now nearly five months after the end of the true-up period in this case. This is even lower than Noranda's load was in March of this year (at that time the load was just under 91%). Indeed, despite its promises, Noranda's track record of predicting when it would reach so-called "full" load is poor. In its 3rd Quarter 2014 earnings call, Noranda said it would fix all of the pots by early 2015.[35] Then, in pre-filed testimony, it said by March 2015.[36] Then, at the hearings it said by May 2015.[37] May is nearly one-half over, and Noranda's load is lower than it was back in February. In its earnings call last week, Noranda now predicts it will be the third quarter of 2015 before it repairs all of the pots, but who knows if that will turn out to be the case, or if there will be other things that cause (as they clearly have in the past) Noranda not to operate at a 98.2% load factor, and stay there.

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[34] At a 97% load factor, Noranda's load would be 4,139,345, or 42,653 MWhs per percent of load factor.
[35] Ex. 72
[36] Ex. 514 (Meyer Surrebuttal) p. 26, l. 15018, Schedule GRM-SUR-4.
[37] Tr. p. 2099, l. 21-24.

26. It is clearly error not to normalize Noranda's load. Indeed, even normalizing it at 97% runs a very significant risk that if Noranda's load were to remain where it is now, the revenue requirement would be too low by $12 million.[38] The bottom line is that Noranda's load is not steady, as the undisputed history of its usage show. Consequently, it must be normalized. Ameren Missouri recommended a normalized load of 97%, using three years of actual data. Indeed, given the facts, it would not be at all unreasonable to use the alternative 10-year actual average of 93.5%, which is still greater than Noranda's current load, or the actual trued-up test year value of 95.4%. Indeed, most significant components of the revenue requirement are based on the trued-up test year figures. Consider that the Commission almost always holds utilities to the end-of the trued-up test year values in setting its revenue requirement, even when known changes occur after the true-up cutoff date. In that light, there is no reason for the Commission to assume that post-true-up cutoff date events will bring Noranda's load back to 98.2%, or that it will stay there. The Commission should normalize Noranda's load as Ameren Missouri proposed.

C. Noranda's Rate Subsidy

27. The Commission's decision to completely ignore all of the class cost of service studies in this case and to instead set Noranda's rate based upon Noranda's private financial circumstances constitutes undue and unlawful discrimination in violation of § 393.130. The Commission attempts to dismiss the Missouri Supreme Court's extensive reliance on *Civic League of St. Louis v. City of St. Louis,* and the legal principles that then Commissioner McQuillen outlined in that case, claiming that it is merely *dicta* in the *Laundry* decision. The Commission's claim that the principles enunciated in *Laundry* are *dicta* rests on a faulty

[38] Because Noranda is in its own rate class, there is no opportunity to receive revenues from any other customers to cover such a shortfall.

foundation, for at its core what *Laundry* makes clear is that the Commission is prohibited by law from setting a customer's rate based upon its private financial circumstances that have *nothing* to do with the character of the service the *utility* is providing. Yet that is precisely – and admittedly – what the Commission did here. In doing so, the Commission committed error as a matter of law.[39]

28. The Commission also erred as a matter of law in exempting Noranda from part of its legitimate share of FAC charges. Section 386.266 does not provide statutory authority to simply exempt one customer from paying its share of fuel and purchased power costs, including transportation, which are tracked in a FAC. Put another way, there is no authority for a "special" or "partial" FAC for one customer, rendering the Commission's FAC cap unlawful for this additional reason.

29. The Commission's decision to grant Noranda a rate subsidy is also unreasonable. It is unreasonable because it is contrary to the competent and substantial evidence of record, it is not supported by the competent and substantial evidence of record and it is arbitrary and capricious. While we will not recite all of the aspects of the record that demonstrate the unreasonableness of the decision here, we note that based on the evidence in the record, the worst-case scenarios Noranda presented are unlikely to occur. Yet the Commission's decision is premised on the presumption that the worst case scenario will materialize in the absence of providing Noranda a subsidy. Noranda admits that it might or might not close the smelter, even if these worst case scenarios were to come true. Noranda admits it might instead go through a

[39] The Legislature has not granted the Commission statutory authority to engage in economic development (or retention) in this manner and thus, the Commission cannot lawfully do so. Nor does the *City of Joplin* case cited by the Commission support the Commission's actions. *City of Joplin* did not involve the Commission knowingly deciding to arbitrarily set a rate for one customer based only on that one customer's private financial needs. It did not involve the principles enunciated by the Commission in *Civic League*, which the Missouri Supreme Court has strongly endorsed. *City of Joplin* can be squared with those principles. The Commission's decision in this case cannot.

reorganization, might sell the smelter or that lenders might restructure debt instead of fomenting a smelter closure that would likely simply hurt the lenders by impairing their collateral. Noranda admits that if the dire circumstances it speculates could occur were to start approaching it would, of course, take evasive action. If this level of proof is sufficient to shift tens of millions of dollars to other customers, then there is little stopping others from asking, based on their own speculation, for similar treatment.

30. The Commission's decision to subsidize Noranda's rates is also unlawful and unreasonable for a number of other reasons. First, it usurps the Legislature's authority (and exceeds the Commission's authority) to decide up economic development/retention subsidies. Second, it forces Ameren Missouri ratepayers to in effect pay an insurance premium (approximately $26 million per year) that is as much or nearly as much as the "protection" the subsidy is assumed to provide.[40] Third, the subsidy being forced on Ameren Missouri's other ratepayers essentially requires them to fund Noranda's lobbying and political speech activities, in violation of core First Amendment principles because it provides additional funds to Noranda – with no strings attached – and indeed includes conditions that encourage if not require Noranda to engage in political activities in relation to public utility regulation.

MOTION FOR RECONSIDERATION

31. The Company respectfully requests that the Commission reconsider its return on equity ("ROE") decision. The Commission has used a ROE for ratemaking purposes that is more than 40 basis points below the undisputed average authorized ROEs for other vertically integrated electric utilities. Indeed, the 9.53% ROE established by the Commission is the *lowest*

[40] That "protection" is the assumed loss of Noranda contribution to rate revenues to cover fixed costs if Noranda were to shut down the smelter, but under the evidence of record, the sums at issue may be less than the cost of the insurance being foisted on Ameren Missouri ratepayers, or not sufficiently greater than the cost of that insurance to justify paying the premium.

of the 19 ROE awards made for vertically integrated electric utilities in 2014.[41] There have only been four ROE awards made for vertically integrated utilities (out of 50) in the past two years that are lower than the 9.53% decided upon in this case.[42] That a 9.53% ROE for Ameren Missouri, which bears all of the risks associated with owning and operating generation, including a single-unit nuclear plant[43] and significant coal-fired generation, is extremely low is made even more clear when one considers that just a few months ago (based on capital market conditions that were materially the same as those cited by the Commission in the Report and Order) the Commission granted a less-risky Missouri natural gas utility an ROE of 10%.[44] In the minds of investors, including Ameren Missouri's sole shareholder, Ameren Corporation, the forgoing facts will necessarily reduce Ameren Missouri's ability to attract capital needed for investment in its generation and energy delivery systems.

32. The competitive disadvantage that this low ROE creates is made all the worse by the removal of (or modification to) other regulatory mechanisms that were formerly in place. Less than three years ago, in File No. ER-2012-0166, the Commission established the two-way major storm tracker. Now, on a record not materially different than the record in that case, it has cancelled it. Investors will view this cancellation very negatively. Similarly, the Commission has cancelled the two-way vegetation management and infrastructure inspection trackers, even though they have operated as intended and have, at times, resulted in reductions in customer rates. Investors will similarly question why these reasonable mechanisms for tracking mandated costs were cancelled. As noted earlier, the Commission has now exposed the Company to significant and uncontrollable transmission charge increases that it has to pay to gain the benefits

[41] Ex. 18 (Hevert Surrebuttal), Schedule RBH-S29.
[42] Ex. 18, p. 4, l. 17 to p. 5, l. 2.
[43] Only one of the four companies whose ROE was set below 9.53% owns nuclear generation at all (Entergy), and it owns multiple nuclear units, which is generally less risky than relying on a single nuclear unit.
[44] *Report and Order*, File No. GR-2014-0152 (*In the Matter of Liberty Utilities*).

of RTO participation. The Company (in part by Commission decision and in part as a function of Missouri law) cannot utilize other regulatory mechanisms that are common in other jurisdictions. For example, there are no formula rates in Missouri, and the Company cannot include (nor can the Commission allow it to include) construction work-in-progress in rate base or utilize a forecasted test year. The Company has no mechanism to address the regulatory lag associated with the lost depreciation and return on rate base additions it places in service for customers' benefit between rate cases. The bottom line is that the record in this case shows that utilities in other states generally have more mechanisms available to them that support investment and mitigate the impacts of cost increases than are available in Missouri.
A specific example of record is provided by MIEC's return on equity witness Mr. Michael Gorman, who testified he recently advised his clients to accept a settlement of 9.83% for a Colorado vertically integrated utility.[45] That Colorado utility not only had an FAC available to it, but also had access to a rider that allowed recovery on environmental capital expenditures between rate cases, and the same utility had the ability to include construction work-in-progress in rate base.[46] Similar mechanisms are not available to Ameren Missouri but yet the Commission has approved only a substantially lower ROE.

33. Given that the Commission has chosen to severely limit the use of such mechanisms, it is particularly problematic for the Company's ability to compete for capital to also be authorized a far below-average ROE. For these reasons, the Commission should reconsider its ROE decision and increase the authorized ROE to account for the Company's competitive position in attracting capital given the limited mechanisms now being made

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[45] Tr. p. 1247, l. 5 to p. 1249, l. 9.
[46] *Id.*

available to it, and even more so if the modification made to the FAC regarding transmission charges is not reversed, as requested above.

WHEREFORE, the Company respectfully requests that the Commission make and enter its order granting rehearing on each of the three issues for which rehearing was sought, as outlined above, and that the Commission reconsider its decision respecting the Company's authorized ROE and increase the Company's authorized ROE to account for the Company's competitive position in attracting capital, for the reasons outlined above.

Respectfully submitted:

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Dated: May 11, 2015

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing document was served on all parties of record via electronic mail (e-mail) on this 11th day of May, 2015.

/s/James B. Lowery
James B. Lowery

Ameren Missouri
MPSC File No. ER-2014-0258
Reconciliation Of Issues Decided by the Commission
Revenue Requirement Impact

	Revenue Requirement	Change In Revenue Requirement
ROE		
9.53% Per Order	121,544,750	
9.25% Per Staff	105,106,117	(16,438,633)
9.30% Per MIEC	108,053,724	(13,491,026)
9.01% Per OPC	91,048,384	(30,496,366)
10.4% Per Company	172,675,604	51,130,854
Energy Efficiency Regulatory Asset & Amortization		
MIEC	120,576,856	(967,894)
Income Tax NOLC & ADIT		
Staff/MIEC	116,117,064	(5,427,686)
Noranda Load		
Company	122,177,309	632,559
Vegetation Management Expense		
MIEC	121,039,481	(505,269)
OPC	120,152,922	(1,391,828)
Company	123,090,343	1,545,593
Infrastructure Inspection Expense		
MIEC	121,195,254	(349,496)
Staff	121,222,554	(322,196)
Company	121,791,420	246,670
Vegetation Management/Infrastructure Inspection Amortization		
MIEC	120,776,890	(767,860)
OPC	121,774,878	230,128
Lost Fixed Cost AAO Amortization		
Company	128,657,050	7,112,300
Solar Rebate Amortization		
MIEC	89,229,261	(32,315,489)
Fukushima Study Cost Amortization		
MIEC	121,452,093	(92,657)
Income Tax Current- IRC Section 199 Deduction		
Staff/MIEC	117,461,324	(4,083,426)
Labadie ESPs		
Sierra Club	98,198,012	(23,346,738)
Union Issues - Workforce Needs		
IBEW Local 1439	132,658,055	11,113,305

EXHIBIT A - Revised

Ameren Missouri (ER-2014-0258)

ROE
ROE 9.25% per MPSC Staff
Value: ($16,438,633)

	Impact	
	Amount	Percent
Residential	($7,901,225)	-0.61%
Small General Service	($1,928,983)	-0.61%
Large General Service	($3,625,400)	-0.61%
Small Primary Service	($1,429,373)	-0.61%
Large Primary Service	($1,303,883)	-0.61%
Large Transmission Service	$0	0.00%
Lighting	($249,297)	-0.61%
MSD	($472)	-0.61%
Total	($16,438,633)	-0.58%

ROE
ROE 9.30% per MIEC
Value: ($13,491,026)

	Impact	
	Amount	Percent
Residential	($6,484,458)	-0.50%
Small General Service	($1,583,098)	-0.50%
Large General Service	($2,975,330)	-0.50%
Small Primary Service	($1,173,073)	-0.50%
Large Primary Service	($1,070,084)	-0.50%
Large Transmission Service	$0	0.00%
Lighting	($204,596)	-0.50%
MSD	($388)	-0.50%
Total	($13,491,026)	-0.47%

ROE
ROE 9.01% per OPC
Value: ($30,496,366)

	Impact	
	Amount	Percent
Residential	($14,658,071)	-1.13%
Small General Service	($3,578,581)	-1.14%
Large General Service	($6,725,712)	-1.13%
Small Primary Service	($2,651,722)	-1.13%
Large Primary Service	($2,418,916)	-1.14%
Large Transmission Service	$0	0.00%
Lighting	($462,488)	-1.14%
MSD	($876)	-1.14%
Total	($30,496,366)	-1.07%

ROE
ROE 10.40% per Company
Value: $51,130,854

	Impact	
	Amount	Percent
Residential	$24,576,033	1.90%
Small General Service	$5,999,924	1.91%
Large General Service	$11,276,472	1.90%
Small Primary Service	$4,445,933	1.89%
Large Primary Service	$4,055,606	1.91%
Large Transmission Service	$0	0.00%
Lighting	$775,417	1.91%
MSD	$1,469	1.91%
Total	$51,130,854	1.80%

Energy Efficiency Regulatory Asset and Amort.
MIEC
Value: ($967,894)

	Impact	
	Amount	Percent
Residential	($465,218)	-0.04%
Small General Service	($113,577)	-0.04%
Large General Service	($213,461)	-0.04%
Small Primary Service	($84,160)	-0.04%
Large Primary Service	($76,772)	-0.04%
Large Transmission Service	$0	0.00%
Lighting	($14,678)	-0.04%
MSD	($28)	-0.04%
Total	($967,894)	-0.03%

Income Tax NOLC & ADIT
Staff/MIEC
Value: ($5,427,686)

	Impact	
	Amount	Percent
Residential	($2,608,816)	-0.20%
Small General Service	($636,909)	-0.20%
Large General Service	($1,197,030)	-0.20%
Small Primary Service	($471,949)	-0.20%
Large Primary Service	($430,514)	-0.20%
Large Transmission Service	$0	0.00%
Lighting	($82,313)	-0.20%
MSD	($156)	-0.20%
Total	($5,427,686)	-0.19%

Noranda Load
Company
Value: $632,559

	Impact	
	Amount	Percent
Residential	$304,039	0.02%
Small General Service	$74,227	0.02%
Large General Service	$139,505	0.02%
Small Primary Service	$55,002	0.02%
Large Primary Service	$50,173	0.02%
Large Transmission Service	$0	0.00%
Lighting	$9,593	0.02%
MSD	$18	0.02%
Total	$632,559	0.02%

Vegetation Management Expense
MIEC
Value: ($505,269)

	Impact	
	Amount	Percent
Residential	($242,857)	-0.02%
Small General Service	($59,291)	-0.02%
Large General Service	($111,433)	-0.02%
Small Primary Service	($43,934)	-0.02%
Large Primary Service	($40,077)	-0.02%
Large Transmission Service	$0	0.00%
Lighting	($7,663)	-0.02%
MSD	($15)	-0.02%
Total	($505,269)	-0.02%

Vegetation Management Expense
OPC
Value: ($1,391,828)

	Impact	
	Amount	Percent
Residential	($668,982)	-0.05%
Small General Service	($163,323)	-0.05%
Large General Service	($306,956)	-0.05%
Small Primary Service	($121,022)	-0.05%
Large Primary Service	($110,397)	-0.05%
Large Transmission Service	$0	0.00%
Lighting	($21,108)	-0.05%
MSD	($40)	-0.05%
Total	($1,391,828)	-0.05%

Vegetation Management Expense
Company
Value: $1,545,593

	Impact	
	Amount	Percent
Residential	$742,889	0.06%
Small General Service	$181,367	0.06%
Large General Service	$340,867	0.06%
Small Primary Service	$134,393	0.06%
Large Primary Service	$122,594	0.06%
Large Transmission Service	$0	0.00%
Lighting	$23,439	0.06%
MSD	$44	0.06%
Total	$1,545,593	0.05%

Infrastucture Inspection Expense
MIEC
Value: ($349,496)

	Impact	
	Amount	Percent
Residential	($167,985)	-0.01%
Small General Service	($41,011)	-0.01%
Large General Service	($77,078)	-0.01%
Small Primary Service	($30,389)	-0.01%
Large Primary Service	($27,721)	-0.01%
Large Transmission Service	$0	0.00%
Lighting	($5,300)	-0.01%
MSD	($10)	-0.01%
Total	($349,496)	-0.01%

Infrastucture Inspection Expense
MIEC
Value: ($322,196)

	Impact	
	Amount	Percent
Residential	($154,863)	-0.012%
Small General Service	($37,808)	-0.012%
Large General Service	($71,058)	-0.012%
Small Primary Service	($28,016)	-0.012%
Large Primary Service	($25,556)	-0.012%
Large Transmission Service	$0	0.000%
Lighting	($4,886)	-0.012%
MSD	($9)	-0.012%
Total	($322,196)	-0.011%

Infrastucture Inspection Expense
Company
Value: $246,670

	Impact	
	Amount	Percent
Residential	$118,562	0.01%
Small General Service	$28,945	0.01%
Large General Service	$54,401	0.01%
Small Primary Service	$21,448	0.01%
Large Primary Service	$19,565	0.01%
Large Transmission Service	$0	0.00%
Lighting	$3,741	0.01%
MSD	$7	0.01%
Total	$246,670	0.01%

Vegetation Management/Infrastructure Inspection Amortization
MIEC
Value: ($767,860)

	Impact	
	Amount	Percent
Residential	($369,072)	-0.03%
Small General Service	($90,104)	-0.03%
Large General Service	($169,345)	-0.03%
Small Primary Service	($66,767)	-0.03%
Large Primary Service	($60,905)	-0.03%
Large Transmission Service	$0	0.00%
Lighting	($11,645)	-0.03%
MSD	($22)	-0.03%
Total	($767,860)	-0.03%

Vegetation Management/Infrastructure Inspection Amortization
OPC
Value: $230,128

	Impact	
	Amount	Percent
Residential	$110,611	0.01%
Small General Service	$27,004	0.01%
Large General Service	$50,753	0.01%
Small Primary Service	$20,010	0.01%
Large Primary Service	$18,253	0.01%
Large Transmission Service	$0	0.00%
Lighting	$3,490	0.01%
MSD	$7	0.01%
Total	$230,128	0.01%

Lost Fixed Cost AAO Amortization
Company
Value: $7,112,300

	Impact	
	Amount	Percent
Residential	$3,418,525	0.26%
Small General Service	$834,589	0.27%
Large General Service	$1,568,557	0.26%
Small Primary Service	$618,429	0.26%
Large Primary Service	$564,135	0.27%
Large Transmission Service	$0	0.00%
Lighting	$107,860	0.27%
MSD	$204	0.27%
Total	$7,112,300	0.25%

Solar Rebate Amortization
MIEC
Value: ($32,315,489)

	Impact	
	Amount	Percent
Residential	($15,532,432)	-1.20%
Small General Service	($3,792,045)	-1.20%
Large General Service	($7,126,904)	-1.20%
Small Primary Service	($2,809,898)	-1.20%
Large Primary Service	($2,563,206)	-1.21%
Large Transmission Service	$0	0.00%
Lighting	($490,075)	-1.21%
MSD	($928)	-1.21%
Total	($32,315,489)	-1.14%

Fukushima Study Cost Amortization
MIEC
Value: ($92,657)

	Impact	
	Amount	Percent
Residential	($44,536)	0.00%
Small General Service	($10,873)	0.00%
Large General Service	($20,435)	0.00%
Small Primary Service	($8,057)	0.00%
Large Primary Service	($7,349)	0.00%
Large Transmission Service	$0	0.00%
Lighting	($1,405)	0.00%
MSD	($3)	0.00%
Total	($92,657)	0.00%

Income Tax Current-IRC Section 199 Deduction
Staff/MIEC
Value: ($4,083,426)

	Impact	
	Amount	Percent
Residential	($1,962,698)	-0.15%
Small General Service	($479,168)	-0.15%
Large General Service	($900,565)	-0.15%
Small Primary Service	($355,062)	-0.15%
Large Primary Service	($323,890)	-0.15%
Large Transmission Service	$0	0.00%
Lighting	($61,927)	-0.15%
MSD	($117)	-0.15%
Total	($4,083,426)	-0.14%

Labadie ESPs
Sierra Club
Value: ($23,346,738)

	Impact	
	Amount	Percent
Residential	($11,221,604)	-0.87%
Small General Service	($2,739,611)	-0.87%
Large General Service	($5,148,923)	-0.87%
Small Primary Service	($2,030,047)	-0.86%
Large Primary Service	($1,851,821)	-0.87%
Large Transmission Service	$0	0.00%
Lighting	($354,061)	-0.87%
MSD	($671)	-0.87%
Total	($23,346,738)	-0.82%

Union Issues-Workforce Needs
IBEW Local 1439
Value: $11,113,305

	Impact	
	Amount	Percent
Residential	$5,341,607	0.41%
Small General Service	$1,304,085	0.41%
Large General Service	$2,450,944	0.41%
Small Primary Service	$966,325	0.41%
Large Primary Service	$881,487	0.41%
Large Transmission Service	$0	0.00%
Lighting	$168,537	0.42%
MSD	$319	0.42%
Total	$11,113,305	0.39%

Ameren Missouri

Case ER-2014-0258

	Revenue	Current Pre-MEEIA	Base Revenue	Revenue Shift	Adjusted Rev	Pre-MEEIA	Increase	Increased Rev	LTS Discount	Target Revenue	Percent Increase
Residential	$1,227,216,898	$11,570,545	$1,215,646,353	$6,078,232	$1,221,724,585	($1,371,890)	$56,068,594	$1,287,991,834	$7,824,074	$1,295,815,908	5.59%
Small General Service	$301,316,805	$1,149,882	$300,166,923	-$1,898,490	$298,268,433	($145,240)	$13,688,430	$312,961,505	$1,910,148	$314,871,653	4.50%
Large General Service	$568,939,338	$4,794,903	$564,144,435	-$3,568,089	$560,576,346	($491,568)	$25,726,525	$590,606,206	$3,590,000	$594,196,206	4.44%
Small Primary Service	$224,819,544	$2,396,378	$222,423,166	-$1,406,777	$221,016,389	($255,496)	$10,143,103	$233,300,374	$1,415,416	$234,715,790	4.40%
Large Primary Service	$202,231,544	$619,097	$201,612,447	$0	$201,612,447	($177,337)	$9,252,598	$211,306,805	$1,291,151	$212,597,956	5.13%
Large Transmission Service	$159,024,866	$0	$159,024,866	$795,124	$159,819,990	$0	$7,334,617	$167,154,607	$0	$0	0.00%
Industrial Aluminum Smelter Service		$0	$0	$0	$0	$0	$0	$0	$0	$150,876,488	-5.12%
Lighting	$38,547,547	$0	$38,547,547	$0	$38,547,547	$0	$1,769,062	$40,316,609	$246,863	$40,563,472	5.23%
MSD	$73,018	$0	$73,018	$0	$73,018	$0	$3,351	$76,369	$468	$76,836	5.23%
Total	$2,722,169,560	$20,530,805	$2,701,638,755	$0	$2,701,638,755	($2,441,530)	$123,986,280	$2,843,714,310	$16,278,119	$2,843,714,310	4.46%

Total Increase $121,544,750

EXHIBIT A - Revised

Residential Class	
	Billing Units
Customer Charge	
Summer Bills	4,172,016
Winter Bills	8,344,032
TOD Bills	408
Low income Surcharge	12,516,456
Total Bills	12,516,456
Energy Charge	
Summer kWh	4,565,669,206
On-peak	38,378
Off-peak	174,833
Energy Eff Charge	4,565,876,802
Winter kWh	
First 750 kWh	4,765,021,199
Over 750 kWh	3,937,120,085
On-peak	0
Off-peak	0
Energy Eff Charge	8,702,132,857
Total kWh	13,268,023,700

Small General Service Class	
	Billing Units
Customer Charge	
Summer Bills	
One-phase	366,244
Three-phase	151,016
Winter Bills	
One-phase	732,488
Three-phase	302,032
TOD Bills	
One-phase	7,092
Three-phase	1,452
6M	68,496
Low income Surcharge	1,560,324
Total Bills	1,628,820
Energy Charge	
Summer kWh	1,163,520,641
On-peak	10,422,800
Off-peak	18,513,900
Energy Eff Charge	1,190,988,187
Winter kWh	
Base	1,710,217,579
Seasonal	485,390,789
On-peak	18,651,329
Off-peak	34,370,431
Energy Eff Charge	2,244,955,752
Total kWh	3,441,087,469

Large General Service	
	Billing Units
Customer Charge	
Summer Bills	41,124
Winter Bills	82,248
TOD Bills	360
Total Bills	123,732
Demand Charge (kW)	
Summer	8,415,761.90
Winter	15,855,959.81
Energy Charge	
Summer kWh	
First 150HU	1,140,083,897
Next 200HU	1,242,304,349
Over 350HU	511,797,661
On-peak	5,054,797
Off-peak	11,084,437
Energy Eff	2,829,079,627
Winter kWh	
Base Energy Charge	
First 150HU	1,868,430,811
Next 200HU	2,033,988,938
Over 350HU	843,340,932
Seasonal Energy	426,408,704
On-peak	8,480,266
Off-peak	18,917,565
Energy Eff	5,063,278,652
Total kWh	8,066,355,291

Small Primary Service	
	Billing Units
Customer Charge	
Summer Bills	2,548
Winter Bills	5,096
TOD Bills	240
Total Bills	7,884
Demand Charge (kW)	
Summer	2,870,165.04
Winter	5,252,950.23
Energy Charge	
Summer kWh	
First 150HU	418,646,201
Next 200HU	511,096,977
Over 350HU	368,414,544
On-peak	13,920,363
Off-peak	30,242,458
Energy Eff	1,209,824,830
Winter kWh	
First 150HU	697,135,073
Next 200HU	858,483,268
Over 350HU	617,854,176
Seasonal Energy	168,549,662
On-peak	24,741,000
Off-peak	53,662,844
Energy Eff	2,179,226,463
Total kWh	3,640,179,900
Reactive Charge	1,111,391
Rider b	
115 kw	6,601.99
69 kw	905,455.13

Large Primary Service	
	Billing Units
Customer Charge	
Bills	780
TOD	48
Low income Surcharge	828
Demand Charge (kW)	
Summer	2,506,949.40
Winter	4,547,498.35
Energy Charge	
Summer kWh	
Energy	1,391,940,050
On Peak	36,010,614
Off-Peak	75,765,308
Energy Eff Charge	672,953,214
Winter kWh	
Energy	2,462,833,566
On Peak	64,070,166
Off-Peak	131,227,581
Energy Eff Charge	1,166,385,481
Total kWh	3,854,773,616
Reactive Charge	533,066
Rider b	
115 kw	600,215.50
69 kw	1,976,071.70

Large Transmission Service	
	Billing Units
Customer Charge	
Summer Bills	4
Winter Bills	8
Low Income Surcharge	12
Demand Charge (kW)	
Summer	1,936,921.1
Winter	3,883,682.1
Reactive Demand Charge	
Summer	0.0
Winter	0.0
Energy Charge	
Summer kWh	
Energy	1,397,501,011
Line of Loss	48,912,535
Winter kWh	
Energy	2,793,512,555
Line of Loss	97,772,940
Total kWh w/o Line Loss	4,191,013,566
Line Losses	146,685,475
Total kWh w/ Line Loss	4,337,699,041

Horizontal - enclosed on existing wood pole	HPS	9500	$	12.41
Horizontal - enclosed on existing wood pole	HPS	25500	$	17.93
Horizontal - enclosed on existing wood pole	HPS	50000	$	31.97
Horizontal - enclosed on existing wood pole	MV	6800	$	12.41
Horizontal - enclosed on existing wood pole	MV	20000	$	17.93
Horizontal - enclosed on existing wood pole	MV	54000	$	31.97
Horizontal - enclosed on existing wood pole	MV	108000	$	63.95
Open bottom on existing wood pole	HPS	5800	$	10.05
Open bottom on existing wood pole	HPS	9500	$	10.98
Open bottom on existing wood pole	MV	3300	$	10.05
Open bottom on existing wood pole	MV	6800	$	10.98
Post top including 17 foot post	HPS	9500	$	22.99
Post top including 17 foot post	MV	3300	$	21.73
Post top including 17 foot post	MV	6800	$	22.99
Directional	HPS	25500	$	22.76
Directional	HPS	50000	$	36.00
Directional	MH	34000	$	22.76
Directional	MH	100000	$	71.96
Directional	MV	20000	$	22.76
Directional	MV	54000	$	36.00
Prior to April 9, 1986				
11,000 Lumens, Mercury Vapor, Post-Top		11000	$	22.99
11,000 Lumens, Mercury Vapor, Open Bottom		11000	$	10.98
11,000 Lumens, Mercury Vapor, Horizontal Enclosed		11000	$	12.41
42,000 Lumens, Mercury Vapor, Horizontal Enclosed		42000	$	31.97
5,800 Lumens, H.P. Sodium, Open Bottom		5800	$	-
16,000 Lumens, H.P. Sodium, Horizontal Enclosed		16000	$	12.41
34,200 Lumens, H.P. Sodium, Directional (2)		34200	$	22.76
140,000 Lumens, H.P. Sodium, Directional		140000	$	71.96
20,000 Lumens, Metal Halide, Directional		20000	$	22.76
1000 INC Wood			$	11.89
2500 INC Wood			$	16.05
4000 INC Wood			$	18.52
6000 INC Wood			$	20.56
10000 INC Wood			$	27.92

6M RATE

Description	Type	Lumens		
Metered service (cust charge per meter)			$	6.71
Energy charge (per kWh)			$	0.0454
Customer charge per account			$	6.71
Energy & Maintenance	HPS	9500	$	3.61
Energy & Maintenance	HPS	25500	$	6.28
Energy & Maintenance	HPS	50000	$	9.07
Energy & Maintenance	MH	5500	$	5.22

Energy & Maintenance	MH	12900	$	6.25
Energy & Maintenance	MV	3300	$	3.61
Energy & Maintenance	MV	6800	$	4.70
Energy & Maintenance	MV	11000	$	6.36
Energy & Maintenance	MV	20000	$	8.43
Energy & Maintenance	MV	54000	$	18.00
Energy Only	HPS	9500	$	1.75
Energy Only	HPS	16000	$	2.98
Energy Only	HPS	25500	$	4.47
Energy Only	HPS	50000	$	7.03
Energy Only	MV	3300	$	1.85
Energy Only	MV	6800	$	3.01
Energy Only	MV	11000	$	4.29
Energy Only	MV	20000	$	6.62
Energy Only	MV	42000	$	11.03
Energy Only	MV	54000	$	15.75
5_6M				
Customer Charge			$	6.71
Metered kWh			$	0.0454
LED				
2500 Lumen			$	0.60
5000 Lumen			$	1.06
4,250 Lumen (Post Top)			$	1.28
12,500 Lumen			$	2.73
19000 Lumen			$	3.94

EXHIBIT A - Revised