55. Assuming that the interconnection customer is agreeable to the transmission owner providing the initial funding for network upgrades, we agree with the ITC Companies that MISO's *pro forma* GIA, FCA, and MPFCA should provide an affected system operator or transmission owner with the flexibility to calculate a revenue requirement for network upgrades that is just and reasonable, and we decline to prescribe the method by which a revenue requirement for network upgrades would be calculated under the initial funding option.

56. In cases where, as here, the Commission institutes a proceeding under section 206 of the FPA, the Commission must establish a refund effective date that is no earlier than publication of notice of the Commission's initiation of its investigation in the *Federal Register*, and no later than five months subsequent to that date. We will establish a refund effective date at the earliest date allowed, i.e., the date the notice of the initiation of the investigation in Docket No. EL15-68-000 is published in the *Federal Register*. The Commission is also required by section 206 to indicate when it expects to issue a final order. The Commission expects to issue a final order in this section 206 proceeding by April 30, 2016.

c. <u>Other Issues</u>

57. We agree with Otter Tail that its complaint in Docket No. EL15-36-000 is not barred by the doctrine of collateral estoppel, as the issue now before the Commission is not the same issue the Commission faced in the Border Winds FCA Order. In the complaint proceeding, the issue before the Commission is whether the *pro forma* FCA is unjust and unreasonable to the extent that it does not permit an affected system operator to elect to initially fund network upgrades. In the Border Winds FCA Order, the issue before the Commission was whether MISO had met its burden to justify the proposed non-conforming provisions of the Border Winds FCA, and the Commission specifically stated that it did not pre-judge whether it would be just and reasonable to amend MISO's *pro forma* FCA to adopt the initial funding option on a generic basis.[116] We also agree with Otter Tail that the doctrine of *res judicata* is also inapplicable to this proceeding because Otter Tail's complaint does not seek to re-litigate the non-conforming FCA that was at issue in the Border Winds FCA Order. Thus, we disagree with MISO's assertion that the Commission need not address the complaint because it could address the issues in the complaint on rehearing of the Border Winds FCA Order.

58. We disagree with the contention of AWEA and WOW that the Commission must reject the complaint and require this matter to be discussed at the MISO stakeholder level. While we encourage parties to follow the MISO stakeholder process when requesting changes to MISO's Tariff, parties have a statutory right to file complaints

---

[116] Border Winds FCA Order, 149 FERC ¶ 61,224 at P 25 n.57.

under section 206 of the FPA. Furthermore, Otter Tail has stated that it attempted to work with MISO on revising its *pro forma* FCA for years and has been unable to effectuate any changes to MISO's Tariff – therefore, we disagree that Otter Tail failed to first seek relief through the MISO stakeholder process.[117]

The Commission orders:

(A) The requests for rehearing of the Border Winds FCA Order filed in Docket No. ER14-2464-002 are denied, as discussed in the body of this order.

(B) Otter Tail's complaint filed in Docket No. EL15-36-000 is granted in part and denied in part, as discussed in the body of this order.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Commission by section 402(a) of the Department of Energy Organization Act and by the FPA, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the FPA (18 C.F.R., Chapter I), the Commission hereby institutes a proceeding in Docket No. EL15-68-000, as discussed in the body of this order.

(D) MISO is hereby directed to submit a filing, within 60 days of the date of publication of notice of the Commission's initiation of Docket No. EL15-68-000, either to (1) report whether it will propose Tariff changes providing that the transmission owner or affected system operator may only elect to provide the initial funding for network upgrades if the interconnection customer agrees to such election, or (2) explain why such changes are not necessary to address the potential that MISO transmission owners may exercise their discretion to increase the network upgrade costs that are directly assigned to interconnection customers under MISO's Interconnection Customer Funding Policy.

(E) Any interested person desiring to be heard in Docket No. EL15-68-000 must file a notice of intervention or motion to intervene, as appropriate, with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (2014)) within 21 days of the date of this order.

(F) The Secretary shall promptly publish in the *Federal Register* a notice of the Commission's initiation of the proceeding under section 206 of the FPA in Docket No. EL15-68-000.

---

[117] Otter Tail Complaint at 22.

(G) The refund effective date in Docket No. EL15-68-000 established pursuant to section 206 of the FPA shall be the date of publication in the *Federal Register* of the notice discussed in Ordering Paragraph (F) above.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)

Appendix 11 – July 20, 2015 MISO TO Rehearing Request (Docket Nos. ER15-36-000, EL15-68-000)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Otter Tail Power Company v. Midcontinent Independent System Operator, Inc.	)	Docket No. EL15-36-___
Midcontinent Independent System Operator, Inc.	)	Docket No. EL15-68-___ (not consolidated)

REQUEST FOR REHEARING OF THE CERTAIN MISO TRANSMISSION OWNERS

Pursuant to section 313 of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*, and Rule 713 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure, 18 C.F.R. § 385.713, the Certain MISO Transmission Owners listed in the footnote[1] submit this request for rehearing of the Commission's June 18, 2015 order,[2] which addressed a complaint filed by Otter Tail Power Company in Docket No. EL15-36 and instituted a new investigation under section 206 of the FPA in Docket No. EL15-68 concerning the justness and reasonableness of certain *pro forma*

---

1 For the purposes of this filing the Certain MISO Transmission Owners include: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois ("Ameren"); Central Minnesota Municipal Power Agency; Cleco Power LLC; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC*Transmission*; ITC Midwest LLC; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Northern Indiana Public Service Company; Northwestern Wisconsin Electric Company; Otter Tail Power Company ("Otter Tail"); and Wabash Valley Power Association, Inc.

2 *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,220 (2015) ("June 18 Order").

agreements under the Midcontinent Independent System Operator Inc.'s ("MISO") Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").[3]

The June 18 Order is flawed because it is inconsistent with Order No. 2003[4] and prior Commission orders providing transmission owners and providers with the unilateral right to self-fund Network Upgrades, and proposes to eliminate this right in the absence of any record evidence of harm. The Commission should grant rehearing of its finding in Docket Nos. EL15-36 and EL15-68 that allowing a Transmission Owner or Affected System Operator unilaterally to elect the self-funding option is potentially unjust and unreasonable.[5] The Commission also should grant rehearing of its initiation of a new FPA section 206 investigation proceeding and its requirement that MISO either file revised Tariff language or explain why such changes are not necessary.[6]

I. SUMMARY AND BACKGROUND

These proceedings involve the issue of whether a Transmission Owner or Affected System Operator in MISO should be allowed to elect to self-fund the cost of

---

3 The June 18 Order also addressed certain issues pending on rehearing in *Midcontinent Independent System Operator, Inc.*, Docket No. ER14-2464. The Certain MISO Transmission Owners as a group take no position on that aspect of the June 18 Order, and do not address it in this filing.

4 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,171, *order on reh'g*, Order No. 2003-C, 2001–2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Utils. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

5 June 18 Order at PP 48-52.

6 *Id.* at P 54.

Network Upgrades required under MISO's *pro forma* Generator Interconnection Agreement ("GIA"), Facilities Construction Agreement ("FCA"), or Multi-Party Facilities Construction Agreement ("MPFCA"). MISO's currently-effective *pro forma* GIA provides two options for funding the costs of Network Upgrades: (1) "Option 2," under which the Interconnection Customer provides up-front funding for Network Upgrades and the Transmission Owner refunds the reimbursable portion of the payment to the Interconnection Customer;[7] or (2) Article 11.3, which permits the Transmission Owner to elect to provide the up-front funding for the initial capital cost of the Network Upgrades.[8] The self-funding option is available under Order No. 2003[9] and the Commission's *pro forma* Large and Small Generator Interconnection Agreements.[10]

While MISO's *pro forma* FCA and MPFCA allowed for the use of Option 2, neither allows an Affected System Operator to elect to fund the costs of the necessary

---

7 Tariff, Attachment FF § III.A.2.d(1). The term "Option 2" is used because at the time this Tariff mechanism was developed, there was also an "Option 1" under the Tariff, which was removed from the Tariff effective March 22, 2011. *See E.ON Climate & Renewables North America, LLC v. Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,076, at PP 4, 36-37 (2011), *order on reh'g*, 142 FERC ¶ 61,048 (2013), *order on reh'g*, 151 FERC ¶ 61,264 (2015) ("*E.On*").

8 Tariff, Attachment X, App. 6, Art. 11.3.

9 Order No. 2003 at P 676; Order No. 2003-A at P 563.

10 *See* Large Generator Interconnection Agreement ("LGIA"), Art 11.3; Small Generator Interconnection Agreement ("SGIA"), Art. 5.2. The current versions of the *pro forma* LGIA and *pro forma* SGIA are posted at http://ferc.gov/industries/electric/indus-act/gi/stnd-gen/2003-C-LGIA.doc and http://ferc.gov/industries/electric/indus-act/gi/small-gen/agreement.docx, respectively.

Network Upgrades. On January 12, 2015, Otter Tail filed a complaint[11] asserting that MISO's Tariff is unjust and unreasonable to the extent that MISO's *pro forma* FCA does not permit an Affected System Operator to elect to provide the initial funding for Network Upgrades, a right provided to directly-connected Transmission Owners under the *pro forma* GIA.[12] Otter Tail demonstrated that there is little difference between an Affected System Operator under an FCA and a Transmission Owner under MISO's *pro forma* GIA, and that principles of comparability require that both sets of entities be treated the same.[13] Otter Tail also pointed out that allowing Affected Transmission Owners to elect the self-funding option is consistent with Order Nos. 2003 and 2003-A, and two orders involving Transmission Owners in MISO.[14] Otter Tail also showed that the cost impact of not having this option under an FCA includes the inability to fund Network Upgrade costs upfront, and recover a return of and return on such investment

---

11 Complaint and Request for Fast-Track Processing of Otter Tail Power Company Against the Midcontinent Independent System Operator, Inc., Docket No. EL15-36-000 (Jan. 12, 2015) ("Complaint").

12 Complaint at 1, 10.

13 Complaint at 10-11.

14 Complaint at 6-9 (citing Order Nos. 2003 and 2003-A; *Midcontinent Indep. Sys. Operator, Inc.* 145 FERC ¶ 61,111 (2013) ("*Hoopeston*"), *order on reh'g & compliance*, 149 FERC ¶ 61,099 (2014); *Midwest Indep. Transmission Sys. Operator, Inc.*, Letter Order, Docket No. ER13-125-000 (Dec. 12, 2012) ("*Sugar Creek*"). The *Hoopeston* proceeding involved an unexecuted GIA between MISO, Hoopeston Wind, LLC ("Hoopeston") and Ameren Services Company on behalf of Ameren Illinois Company.

from the interconnecting generator.[15] Otter Tail therefore sought to require that the *pro forma* FCA be amended to add a self-funding option.[16]

The Commission in the June 18 Order granted the Complaint in part, finding that comparability principles dictated that the same funding options be offered under MISO's *pro forma* GIA, FCA and MPFCA.[17] However, the Commission rejected Otter Tail's request that the *pro forma* FCA be revised to allow an Affected System Operator to self-fund Network Upgrades.[18] The Commission instead stated that GIA Article 11.3 may be unjust, unreasonable, unduly discriminatory or preferential because allowing a Transmission Owner to elect initially to fund the Network Upgrades could result in discriminatory treatment of different Interconnection Customers.[19] The Commission also found that such election could deprive the Interconnection Customer of other options to finance the cost of the Network Upgrades on more favorable terms and rates, and trigger other financing and security obligations.[20] The Commission stated that allowing Transmission Owners the unilateral right to make this election is contrary to its prior decision in *E.On* requiring Option 1's elimination.[21]

---

15 Complaint at 21.

16 Complaint at 16-17, 20.

17 June 18 Order at P 47. The Certain MISO Transmission Owners support this aspect of the June 18 Order.

18 *Id.* at 48.

19 *Id.*

20 *Id.* at P 49.

21 *Id.*

The Commission stated that the "potentially unjust and unreasonable" provisions of GIA Article 11.3 could be remedied by revising the Tariff so that a Transmission Owner or Affected System Operator could only elect the self-funding option if the Interconnection Customer agreed, and suggested revisions to GIA Article 11.3 to implement this determination.[22] Accordingly, the Commission ordered MISO either to: (1) report whether it will propose Tariff changes suggested by the Commission; or (2) explain why such changes are not necessary to address the potential that Transmission Owners may exercise their discretion to increase the Network Upgrade costs directly assigned to Interconnection Customers.[23] MISO's response is due August 17, 2015.

II. SPECIFICATION OF ERRORS AND STATEMENT OF ISSUES

In accordance with Order No. 663-A[24] and Commission Rule 713(c),[25] the Certain MISO Transmission Owners provide the following statement of issues and specification of errors:

1. In determining that Article 11.3 to the GIA is potentially unjust and unreasonable, the Commission has ignored its prior orders, and erred by failing to explain its departure or distinguish its earlier determinations that the self-funding option is just and reasonable. These failures to distinguish its earlier precedent or explain the reasons for its departure render the June 18 Order arbitrary, capricious, and contrary to reasoned decisionmaking. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41 (1983) ("*Motor Vehicle Manufacturers*"); *Idaho Power Co. v. FERC*, 312 F.3d 454, 461-464 (D.C. Cir. 2002) ("*Idaho*

22 June 18 Order at P 53. The Commission indicated that similar changes should be made to the *pro forma* FCA and MPFCA.

23 *Id.* at P 54.

24 *Revision of Rules of Practice and Procedure Regarding Issue Identification*, Order No. 663-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,211 (2006).

25 18 C.F.R. §§ 385.713(c)(1)-(2).

Power"); *PG&E Gas Transmission v. FERC*, 315 F.3d 383, 388-390 (D.C. Cir. 2003) ("*PG&E*"); *Williams Gas Processing-Gulf Coast Co., L.P. v. FERC*, 475 F.3d 319, 326-327 (D.C. Cir. 2006) ("*Williams*").

2. The Commission erred by failing to respond to the showings that it previously found that a Transmission Owner's unilateral election of the self-funding option is proper and not unduly discriminatory. This further renders the Commission's determination arbitrary, capricious, and contrary to reasoned decisionmaking. *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 642 (D.C. Cir. 2010) ("*Florida Gas*"); *PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194, 1198-1200 (D.C. Cir. 2005) ("*PPL Wallingford*").

3. Because no party alleged or made any record showing that allowing Transmission Owners to elect the self-funding option is unjust or unreasonable, the Commission failed to provide a reasoned analysis based on substantial evidence to support its conclusions. *See Florida Gas*, 604 F.3d at 639, 641, 645; *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 841, 843-44 (D.C. Cir. 2006) ("*National Fuel*"); *City of Centralia, Wash. v. FERC*, 213 F.3d 742, 743, 749-50 (D.C. Cir. 2000) ("*Centralia*"); *City of Kaukauna, Wisc. v. FERC*, 214 F.3d 888, 894 (7th Cir. 2000) ("*Kaukauna*").

III. REHEARING REQUEST

A. The Commission Erred in Disregarding and Failing to Explain the Departure from Its Prior Precedent that It Is Just and Reasonable for a Transmission Owner to Unilaterally Elect to Self-Fund Network Upgrades

The Administrative Procedure Act[26] requires that a Commission decision or order not be arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.[27] In addition, Commission decisions must be consistent with the Commission's prior orders or else the Commission must provide a reasoned explanation for any departure from its established precedent, and the failure to do so constitutes reversible

26 5 U.S.C. § 706.

27 *Id.* § 706(2)(A); *see also Motor Vehicle Manufacturers*, 463 U.S. at 41.

error.[28] The courts have remanded Commission decisions that contradict prior Commission orders without explanation.[29] The June 18 Order contradicts the Commission's prior orders without sufficient explanation, and thus fails to meet these standards. The Commission should grant rehearing to remedy these errors.

As Otter Tail pointed out in its Complaint, the Commission in Order Nos. 2003 and 2003-A, as well as in *Hoopeston*, made it clear that a Transmission Owner has the right to elect to self-fund Network Upgrades.[30] In Order No. 2003, the Commission stated, "Network Upgrades, which are defined as all facilities and equipment constructed at or beyond the Point of Interconnection for the purpose of accommodating the new Generating Facility, would be funded initially by the Interconnection Customer *unless the Transmission Provider elects to fund them.*"[31] The Commission in Order No. 2003-A affirmed that "the Interconnection Customer must initially fund the Network Upgrades

---

[28] *See Williams*, 475 F.3d at 326, 330 (remanding decision that was inconsistent with prior findings and stating that "[r]easoned decisionmaking necessarily requires consideration of relevant precedent"); *Idaho Power*, 312 F.3d at 461 (rejecting and vacating Commission interpretation of tariff that is contrary to prior Commission orders and the Commission's own prior interpretations of the subject tariff provisions); *see also PG&E*, 315 F.3d at 388 (vacating and remanding Commission orders where the Commission "utterly failed to confront" and distinguish prior precedent, and the Commission's attempts to distinguish its precedents "were alternately nonexistent, misleading, and irrelevant").

[29] *See Williams*, 475 F.3d at 327 (rejecting change in jurisdictional treatment of pipeline facilities when Commission's "rationale could hardly be more inconsistent with precedent" and where rationale was not supported by a reasoned analysis in the orders themselves); *Consol. Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964, 971 (D.C. Cir. 2003) ("*Consolidated Edison*") (rejecting purported limitation in tariff provisions when the Commission's earlier order had a broad interpretation of the RTO's emergency authority).

[30] *See* Complaint at 4, 7-9.

[31] Order No. 2003 at P 676 (emphasis added) (footnote omitted); *see also* Complaint at 7-8.

associated with the interconnection, and will be reimbursed by the Transmission Provider, unless the Transmission Provider chooses to pay for them itself."[32] The provisions of the Commission's *pro forma* LGIA and MISO's *pro forma* GIA are virtually identical, and both provide that unless a "Transmission Owner elects to fund the capital for the Network Upgrades . . . [such facilities] shall be solely funded by Interconnection Customer."[33] Nothing in the Commission's *pro* forma LGIA or SGIA requires a transmission provider to obtain the Interconnection Customer's consent prior to making this election. Notably, while the Commission has made it clear that as an independent entity, MISO is entitled to adopt Tariff mechanisms that depart from Order No. 2003's interconnection funding policy,[34] the Commission has never indicated that Article 11.3 of its *pro forma* LGIA does not apply to MISO.

In addition, *Hoopeston* confirmed that it is appropriate for Transmission Owners to have an option to self-fund, stating, "it is just and reasonable and not unduly discriminatory for the transmission owner to recover capital costs for network upgrades through a network upgrade charge established using the formula in Attachment GG and consistent with MISO's participant funding allocation methodology."[35] The Commission also found that

---

32 Order No. 2003-A at P 563; *see also* Complaint at 8. As Otter Tail pointed out, the term Transmission Provider when used in Order Nos. 2003, et al. refers to a Transmission Owner that participates in an RTO or an independent system operator. Complaint at 3.

33 *See* LGIA, Art. 11.3; MISO GIA, Art. 11.3; *see also* SGIA, Art.5.2.

34 *See* Order No. 2003 at PP 698-99.

35 *Hoopeston* at P 41. The Commission found that it would be unduly discriminatory to allow the Transmission Owner to recover costs other than the (continued . . .)

> Ameren's proposal, as revised above, is a reasonable implementation of the self-fund option in the context of MISO's Tariff with its participant funding methodology. In Order Nos. 2003 and 2003-A, the Commission established that a non-independent transmission owner could elect to self-fund. Therefore, Ameren as a transmission owner may select self-funding under Article 11.3 of the *pro forma* GIA.[36]

Nothing in these orders limits a Transmission Owner's ability to self-fund Network Upgrades or suggests why it is inappropriate for the MISO *pro forma* GIA to contain a self-funding option that is expressly set forth in the Commission's *pro forma* LGIA and SGIA. The Commission fails to explain why its prior rulings that Transmission Owners are entitled to self-fund Network Upgrades no longer apply, or why it has deviated from its past precedent. Contrary to reasoned decision making,[37] the June 18 Order totally fails to respond to Otter Tail's assertions that Order Nos. 2003 and 2003-A provide Transmission Owners with this right.[38] For these reasons, the June 18 Order is arbitrary and capricious, and should be reversed on rehearing.

The Commission's error is further illustrated by its failure to respond adequately to Otter Tail's argument that *Hoopeston* found the use of the self-funding option to be just and reasonable.[39] The Commission's efforts to distinguish *Hoopeston* fall short because they demonstrate a fundamental misconstruction of *Hoopeston* that renders the

---

(. . . continued)

return of and on the capital costs, in part because an Interconnection Customer would only be required to pay the capital costs under Option 2. *Id.*

36 *Hoopeston* at P 42 (footnote omitted).

37 *See Williams*, 475 F.3d at 326, 329; *Consolidated Edison*, 347 F.3d at 971.

38 *See* Complaint at 7-8, 13 (discussing Order Nos. 2003 and 2003-A).

39 *See* Complaint at 13 (discussing *Hoopeston*).

Commission's conclusions arbitrary and capricious. Specifically, in the June 18 Order, the Commission states:

> We disagree with Otter Tail's assertion that *Hoopeston* provides support for applying the unilateral initial funding option to MISO's *pro forma* FCA. In *Hoopeston*, the Commission did not consider whether the *unilateral* aspect of the initial funding option in Article 11.3 of MISO's *pro forma* GIA was just and reasonable, and no party challenged the Tariff language. Rather, the Commission was presented for the first time with the issue of how MISO's Interconnection Customer Funding Policy should be implemented under the initial funding option, as it was written into MISO's *pro forma* GIA.[40]

The Commission's assertion that "[i]n *Hoopeston*, the Commission did not consider whether the *unilateral* aspect of the initial funding option in Article 11.3 of MISO's *pro forma* GIA was just and reasonable, and no party challenged the Tariff language" is simply wrong. In its protest in that proceeding, Hoopeston argued that "Ameren, a non-independent transmission owner, is barred by Orders 2003 et al from selecting and developing its own pricing mechanisms to self-fund network upgrades."[41] Hoopeston also claimed that "[t]he Commission in [*E.On*] also reasoned that allowing a transmission owner sole discretion to select pricing policy creates unacceptable opportunities for undue discrimination."[42] Hoopeston further maintained that Ameren's self-funding "schema" violated *E.On*.[43] Thus, the issue of whether self-funding is just and reasonable was squarely before the Commission in the *Hoopeston* proceeding.

40 June 18 Order at P 51.

41 Motion to Intervene and Protest of Hoopeston Wind, LLC, Docket No. ER13-2157-000, at 2 (Sept. 3, 2013) ("Hoopeston Protest") (footnote omitted).

42 Hoopeston Protest at 17.

43 *Id.* at 18.

Indeed, the Commission in *Hoopeston* recognized that these arguments had been raised.[44] In response to these arguments, the Commission found that with the exclusion of certain costs from the charges the Interconnection Customer would pay, it is appropriate for a Transmission Owner to elect the self-fund option.[45] Thus, any claim that issues of a Transmission Owner's right to select the self-funding option were not before the Commission in *Hoopeston* is incorrect.

The Commission relies on *E.On* in support of its determination that a Transmission Owner's election of the self-funding option can lead to the imposition of unreasonable costs, stating that "there is the possibility for an increase in costs presented by a transmission owner's unilateral election to provide initial funding as compared to Option 2."[46] However, in *Hoopeston*, the Commission found that while it could be unduly discriminatory to allow a Transmission Owner the discretion to unreasonably increase an Interconnection Customer's costs if it has the ability to recover costs other than the return of and return on capital costs, "once MISO has revised the Restated Hoopeston GIA to remove the recovery of costs other than the return of and on the capital costs of network upgrades, the self-fund option will be implemented in a way that is comparable to and not unduly discriminatory vis-à-vis Option 2."[47] Thus, the Commission specifically determined that limiting cost recovery to the return of and a

44 June 18 Order at PP 20-21.

45 *See Hoopeston* at P 42 (Ameren's proposal, as revised, "is a reasonable implementation of the self-fund option" and that once revised, "the self-fund option will be implemented in a way that is comparable to and not unduly discriminatory vis-à-vis Option 2.").

46 June 18 Order at P 52.

47 *Hoopeston* at P 42.

return on capital costs is sufficient to address the potential for the unreasonable imposition of costs arising from a Transmission Owner's discretion to elect the self-funding mechanism. Accordingly, the Commission directly addressed the issue of whether the self-fund option is just and reasonable, and the June 18 Order provides no reason why the Commission's finding in *Hoopeston* is no longer valid or otherwise explains the June 18 Order's departure from this precedent. The Commission's failure to reconcile its *Hoopeston* determinations with its findings in the June 18 Order renders the June 18 Order arbitrary and capricious.

Finally, the Commission also erred by failing to provide a meaningful response to Otter Tail's showings that the Commission had previously found the unilateral election of the self-funding option by a Transmission Owner to be just and reasonable. The Commission's failure to address these arguments in any meaningful fashion further renders the Commission's determination arbitrary, capricious, contrary to reasoned decisionmaking, and an unexplained departure from precedent.[48] The Commission should grant rehearing to reverse its error.

---

48 *See, e.g., PPL Wallingford*, 419 F.3d at 1198 ("An agency's failure to respond meaningfully to objections raised by a party renders its decision arbitrary and capricious.") (internal quotations omitted), 1199-1200 (further criticizing the Commission's failure to respond to Petitioners' arguments below); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001) ("Unless the Commission answers objections that on their face seem legitimate, its decision can hardly be classified as reasoned."); *K N Energy v FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992) ("[W]e cannot ignore the Commission's unwillingness to address an important challenge to its stated benefit rationale . . . . It most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it – that it conduct a process of *reasoned* decisionmaking.").

B. The Commission's Findings Are Flawed in the Absence of Any Record Evidence of Actual or Potential Harm

As noted above, the Administrative Procedure Act requires that a Commission decision or order not be arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.[49] Compliance with these standards requires that the Commission be able to demonstrate that "'it has made a reasoned decision based upon substantial evidence in the record.'"[50] Substantial evidence means more than a scintilla but less than a preponderance of the evidence.[51] The courts have remanded decisions that lacked "hard," substantial evidence to support the Commission's findings.[52] When the Commission acts in response to a theoretical threat, it must provide a substantial explanation as to why the action is necessary, and also show why existing remedies such as the Commission's complaint procedures are inadequate.[53]

The Commission's findings in the June 18 Order lack any evidentiary or record support, and do not satisfy the requirements of reasoned decisionmaking. While the Commission in the June 18 Order seeks to restrict the self-funding option based on the assertion that the right of Transmission Owners to elect the self-funding option results in

---

49 *See supra* Part III.A and n.27.

50 *Florida Gas*, 604 F.3d at 639 (citing *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 119 (D.C. Cir. 2004) and other cases); *Kaukauna*, 214 F.3d at 894 (In reviewing a Commission order, the court must determine whether "each essential element of the Commission's order is upheld by the substantial evidence.").

51 *Florida Gas*, 604 F.3d at 645.

52 *Centralia*, 213 F.3d at 743, 749-50; *see also National Fuel*, 468 F.3d at 841, 844 (remanding a rule when the Commission "has provided no evidence of a real problem").

53 *National Fuel*, 468 F.3d at 844-45.

"the possibility for an increase in costs,"[54] there is no record evidence – not even a scintilla – to support this contention. Nor is there any record evidence or allegation that the self-funding option has been exercised in a manner that is actually or potentially unjust, unreasonable or unduly discriminatory. Rather than basing its decision on the evidence before it, the Commission simply states that election of the self-funding option will potentially allow Transmission Owners to impose unreasonable costs on an Interconnection Customer.

Nothing in the record supports this contention. In fact, the only concern raised about a Transmission Owner's right to make this election was the statement in the protest filed by the American Energy Wind Association and Wind on the Wires ("AWEA/WOW") arguing that issues of whether an Affected System Operator should have the right to select the self-funding option should be decided through the stakeholder process rather than in response to a complaint.[55] At no point did AWEA/WOW indicate or provide any evidence showing that it would be unduly discriminatory or unjust and unreasonable to allow an Affected System Operator the discretion to elect the self-funding option or that there is otherwise anything problematic or unduly discriminatory about the self-funding option under GIA Article 11.3. This total lack of evidentiary support renders the June 18 Order inconsistent with reasoned decisionmaking and constitutes reversible error.[56]

---

[54] June 18 Order at P 52.

[55] Protest of the American Wind Energy Association and Wind on the Wires, Docket No. EL15-36-000, at 6-7 (Feb. 2, 2015).

[56] *See Florida Gas*, 604 F.3d at 639; *Kaukauna*, 214 F.3d at 894; *Centralia*, 213 F.3d at 743, 749-50.

The Commission also fails to explain adequately why the removal of the self-funding option is necessary when its removal can impose costs on Transmission Owners by depriving them of the ability to fund Network Upgrade costs up front and recover a return of and return on such investment from the Interconnection Customer. Moreover, the Commission fails to address why other avenues of relief are available to Interconnection Customers if they feel the self-funding option was elected improperly, such as MISO's dispute resolution procedures[57] or filing a complaint pursuant to FPA section 206 are inadequate to protect an Interconnection Customer that believes that a Transmission Owner's case-specific election of the self-funding option is unfair, unduly discriminatory, or unjustly imposes costs on the Interconnection Customer.

Finally, any claims of harm – potential or actual – are belied by the Commission's findings in *Hoopeston* that "once MISO has revised the Restated Hoopeston GIA to remove the recovery of costs other than the return of and on the capital costs of network upgrades, the self-fund option will be implemented in a way that is comparable to and not unduly discriminatory vis-à-vis Option 2."[58] The Commission should therefore grant rehearing of the June 18 Order and preserve the ability of Transmission Owners to unilaterally elect to self-fund Network Upgrades consistent with its holdings in *Hoopeston*.

---

[57] *See* Tariff, Attachment HH; *see also id.*, Attachment X § 13.5.

[58] *Hoopeston* at P 42.

IV. CONCLUSION

For the foregoing reasons, the Certain MISO Transmission Owners request that the Commission grant rehearing of its findings in the June 18 Order that allowing a Transmission Owner or Affected System Operator to unilaterally elect the self-funding option is potentially unjust and unreasonable.[59] It should also grant rehearing of its requirement that MISO file revised Tariff language allowing such elections only when mutually agreed to by the Interconnection Customers, or to explain why such changes are not necessary.

Respectfully submitted,

<u>/s/ David S. Berman</u>
Wendy N. Reed
Matthew J. Binette
David S. Berman
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005-3802

Attorneys for the
Certain MISO Transmission Owners

July 20, 2015

---

59 June 18 Order at PP 48-52.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 20th day of July, 2015.

<u>/s/ David S. Berman</u>
David S. Berman
WRIGHT & TALISMAN, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200

Attorney for the
Certain MISO Transmission Owners

Document Content(s)

Appendix 12 – August 17, 2015 MISO Informational Report (Docket Nos. ER14-2464-002, EL15-36-000, EL15-68-000)

Jacob Krouse
Corporate Counsel
Direct Dial: 317-249-5715
Email: jkrouse@misoenergy.org

August 17, 2015

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.
FERC Docket No. ER14-2464-002, EL15-36-000, EL15-68-000
Commission Proposed Language Informational Report

Dear Secretary Bose:

Pursuant to the Federal Energy Regulatory Commission's ("Commission") June 18, 2015 Order[1] issued in Docket Nos. ER14-2464-002, EL15-36-000, and EL15-68-000, the Midcontinent Independent System Operator, Inc. ("MISO") hereby respectfully submits a report to the Commission regarding the "self-fund" mechanism in MISO's *pro forma* GIA.

I. Background

In the June 18 Order, the Commission addressed a complaint, request for rehearing, and opened an investigation into MISO's *pro forma* GIA regarding the "self-fund" mechanism. The Commission denied the complaint in part, and granted the complaint in part, requiring MISO to address the "self-fund" option in MISO's *pro forma* Facilities Construction Agreement ("FCA") and Multi-Party Facilities Construction Agreement ("MPFCA"). However, the Commission also found that "MISO's *pro forma* GIA may similarly be unjust, unreasonable, unduly discriminatory or preferential because it provides opportunities for undue discrimination and for increasing costs to interconnection customers where there is no increase in service…"[2]

The Commission required MISO to "(1) report whether it will propose Tariff changes as suggested by the Commission, providing that the transmission owner or affected system operator may only elect to provide the initial funding for network upgrades if the interconnection customer agrees to such election, or (2) explain why such changes are not necessary to address the potential that MISO transmission owners may exercise their discretion to increase the network upgrade costs

1 *Midcontinent Indep. Sys. Operator, Inc.* 151 FERC ¶ 61,220 (2015) ("June 18 Order")
2 *Id.* at P2.

that are directly assigned to interconnection customers under MISO's Interconnection Customer Funding Policy."[3]

II. MISO REPORT

MISO will propose the Tariff changes as suggested by the Commission when the Commission addresses the comments, protests, and request for rehearing filed in the instant and related dockets. MISO has heard concerns from some Transmission Owners that echo the filings made in these related dockets and believes the Commission is the appropriate authority to address those concerns.

III. COMMUNICATIONS

Correspondence, pleadings and other materials regarding this filing should be addressed to the following person:

Jacob T. Krouse*
Midcontinent Independent System
Operator, Inc.
P.O. Box 4202
Carmel, IN 46082-4202
Telephone: 317-249-5715
jkrouse@misoenergy.org

* Person authorized to receive service

MISO has served all parties provided in the Commission's eService list for the above-referenced dockets. In addition, MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, MISO Advisory Committee participants, as well as all state commissions within the Region. In addition, the filing has been posted electronically on MISO's website at https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx for other interested parties in this matter.

---

3 *Id.* at 54.

IV. CONCLUSION

Wherefore, MISO respectfully requests that the Commission accept this filing in compliance with the Commission's June 18 Order.

Sincerely,

/s/ Jacob T. Krouse

Jacob T. Krouse

Document Content(s)

Appendix 13 – August 19 Order Granting Rehearing Request (Docket Nos. ER15-36-000, EL15-68-000)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Otter Tail Power Company v. Midcontinent Independent System Operator, Inc.	Docket Nos. EL15-36-001
Midcontinent Independent System Operator, Inc.	EL15-68-001

ORDER GRANTING REHEARING FOR
FURTHER CONSIDERATION

(August 19, 2015)

Rehearing has been timely requested of the Commission's order issued on June 18, 2015, in this proceeding. *Otter Tail Power Company v. Midcontinent Independent System Operator, Inc., and Midcontinent Independent System Operator, Inc.*, 151 FERC ¶ 61,220 (2015). In the absence of Commission action within 30 days from the date the rehearing request was filed, the request for rehearing (and any timely requests for rehearing filed subsequently)[1] would be deemed denied. 18 C.F.R. § 385.713 (2015).

In order to afford additional time for consideration of the matters raised or to be raised, rehearing of the Commission's order is hereby granted for the limited purpose of further consideration, and timely-filed rehearing requests will not be deemed denied by operation of law. Rehearing requests of the above-cited order filed in this proceeding will be addressed in a future order. As provided in 18 C.F.R. § 385.713(d), no answers to the rehearing requests will be entertained.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

---

[1] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,173 (2001) (clarifying that a single tolling order applies to all rehearing requests that were timely filed).

Document Content(s)

Appendix 14 – September 30, 2015 Supportive Comments of AECS (Docket No. EL15-68)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	))	**Docket No. EL15-68-000**

SUPPORTIVE COMMENTS OF
ALLIANT ENERGY CORPORATE SERVICES, INC.

Pursuant to Rule 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "the Commission"), 18 C.F.R. §§ 385.212 (2015), Alliant Energy Corporate Services, Inc. ("Alliant Energy") respectfully provides these comments[1] in support of the Commission's investigation into the Midcontinent Independent System Operator, Inc.'s ("MISO") network upgrade funding rules initiated in the above-captioned docket. Alliant Energy requests that the Commission continue to pursue changes to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") related to funding network upgrades in an effort to lower the cost of such upgrades to customers.

I. Communications

Alliant Energy requests that all communications regarding these comments be addressed to the following persons:

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.
Street: 4902 North Biltmore Lane
Madison, WI 53718
Telephone: 608-458-6217
E-Mail: CortlandtChoate@AlliantEnergy.com

Angela Cavallucci
Regulatory Relations Manager
Alliant Energy Corporate Services, Inc.
Street: 801 Pennsylvania Avenue, NW
Washington, DC 20004
Telephone: 202-347-8136
E-Mail: AngelaCavallucci@AlliantEnergy.com

[1] On July 28, 2015, Alliant Energy filed a "Motion to Intervene Out-of-Time" in Docket No. EL15-68-000, and so does not include a motion to intervene in these supportive comments.

II. Background

On June 18, 2015, the Commission issued an Order,[2] which, in part, instituted a Federal Power Act Section 206 Proceeding regarding the justness and reasonableness of MISO's *pro forma* Facilities Construction Agreement, Generator Interconnection Agreement, and Multi-Party Facilities Construction Agreement (collectively, "the Agreements"). Among other things, the Commission argued that the Agreements may be unjust, unreasonable, unduly discriminatory or preferential because they "[provide] opportunities for undue discrimination and for increasing costs to interconnection customers where there is no increase in service."[3] The Commission found that the current Tariff language "could be remedied by revising MISO's Tariff to provide that the transmission owner ("TO") or affected system operator may only elect to provide the initial funding for network upgrades if the interconnection customer agrees to such election; otherwise, the interconnection customer must fund the network upgrades associated with its interconnection request through other means."[4] The Commission required MISO to respond to the Commission's investigation within 60 days.

On August 17, 2015, MISO filed an Informational Report[5] in response to the Commission's June 18 Order. In the August 17 Report, MISO stated that it "will propose the Tariff changes as suggested by the Commission when the Commission addresses the comments, protests, and request for rehearing filed in the instant and related dockets."[6] MISO cited concerns MISO heard from the MISO TOs that were also raised in the proceedings and filings mentioned. MISO argued that "the Commission is the appropriate authority to address those concerns,"[7] and therefore did not submit

[2] *Midcontinent Indep. Sys. Operator, Inc.* 151 FERC ¶ 61,220 (2015) (the "June 18 Order").
[3] *Id.* at P 2.
[4] *Id.* at P 53.
[5] *Midcontinent Indep. Sys. Operator, Inc.* "Commission Proposed Language Informational Report" in Docket Nos. ER14-2464-002, EL15-36-000, and EL15-68-000 (the "August 17 Report").
[6] *Id.* at 2.
[7] *Id.*

any amended Tariff language or reasons as to why no such Tariff amendments were necessary, as required by the June 18 Order.

On September 9, 2015, the Commission issued a Notice of Filing[8] providing interested parties the opportunity to comment on the Commission's preliminary findings in the Commission's June 18 Order and MISO's August 17 Report in response. The Commission established a comment date of September 30, 2015.

III. Alliant Energy Supports the Commission's Investigation into the MISO Tariff as a Means to Ensure Just and Reasonable Rates for Interconnection Customers and Their Ratepayers.

A. Alliant Energy Supports an Approach to Determining Who Will Fund Network Upgrades Based on Considerations of Costs to Customers.

Alliant Energy supports the Commission's efforts to allow Interconnection Customers ("IC") more involvement in the decision to fund necessary network upgrades. As currently drafted, the MISO Tariff provides a TO the unilateral opportunity to decide if it will fund a network upgrade. This unilateral opportunity provided to the TO can prevent the IC from having any involvement in the decision of how network upgrades will be funded. To arrive at a funding result that is in the best interest of customers, greater consideration should be given to both an IC's funding costs and a TO's funding costs. The current MISO Tariff does not allow for an IC's funding costs to be explored and considered, unless the TO decides in its sole discretion that it does not wish to self-fund. Without a transparent process for determining who will fund a network upgrade and the associated cost, customers are unaware as to whether decisions are being made in the customers' best interest.

Additionally, the current Tariff process provides no incentive for TOs to provide the least cost alternative in their proposal or when determining if they will choose to fund the network

[8] *Midcontinent Indep. Sys. Operator, Inc.* "Notice of Filing" in Docket No. EL15-68-000 (September 9, 2015).

upgrade. The ICs have little recourse should a TO unilaterally choose to fund the network upgrade, aside from a time-consuming and costly section 206 complaint filed at FERC. Allowing more transparency and funding alternatives in the process would provide some semblance of a "check and balance" on the costs of a project, while providing a modicum of assurance that costs are being appropriately considered in the ultimate decision of who will fund the network upgrade. A process that provides cost transparency and more options for funding a project incentivizes the ultimate funder of the network upgrade to ensure the solution is one that is most beneficial to ratepayers.

A Tariff modification would provide, at a minimum, a means by which TOs, ICs, and customers can recognize and consider the costs and benefits of the options available and support selecting the option which is in the best interest of customers. While Alliant Energy does not support allowing unilateral determinations of funding network upgrades by either party (TO or IC), Alliant Energy does support a balanced approach that takes costs to customers into consideration when determining which party should fund the network upgrade.

B. Alliant Energy Expects MISO to Comply with the Ultimate Requirements of the Commission Regarding Network Upgrade Funding.

Alliant Energy does not take issue with MISO's August 17 Filing, submitted in response to the Commission's June 18 Order. However, Alliant Energy fully expects MISO to comply with any final decision the Commission levies with regard to the network upgrade funding provisions of the MISO Tariff. Alliant Energy reiterates its support for amending the MISO Tariff to provide more transparency and optionality in the network upgrade process, as previously discussed in these supportive comments.

IV. Conclusion

WHEREFORE, for the reasons discussed above, Alliant Energy respectfully requests that the Commission consider its comments herein.

Respectfully submitted,

Alliant Energy Corporate Services, Inc.

/s/ Cortlandt C. Choate, Jr.

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.
4902 North Biltmore Lane
Madison, WI 53718
Telephone: 608-458-6217
E-Mail: CortlandtChoate@AlliantEnergy.com

Angela Cavallucci
Regulatory Relations Manager
Alliant Energy Corporate Services, Inc.
801 Pennsylvania Avenue, NW
Washington, DC 20004
Telephone: 202-347-8136
E-Mail: AngelaCavallucci@AlliantEnergy.com

September 30, 2015

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have on this 30th day of September, 2015, caused a copy of the foregoing Comments of Alliant Energy Corporate Services, Inc. to be sent to each person designated on the official service list compiled by the Secretary of the Commission in Docket No. EL15-68-000.

/s/ Cortlandt C. Choate, Jr.

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.

Document Content(s)

Appendix 15 – June 30, 2015 Order Granting Clarification and Denying Rehearing Request (Docket No. ER13-358)

151 FERC ¶ 61,269
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
and Tony Clark.

Midcontinent Independent System Operator, Inc. — Docket No. ER15-358-001

ORDER GRANTING CLARIFICATION AND DENYING REHEARING

(Issued June 30, 2015)

1. In this order, we grant a motion for clarification by Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) and Southern Illinois Power Cooperative (Southern Illinois), and deny a request for rehearing by the Coalition of MISO Transmission Customers (MISO Coalition), of the Commission's order issued January 5, 2015.[1]

I. Background

2. On November 6, 2014 (November 6 Filing), pursuant to sections 205 and 219 of the Federal Power Act (FPA)[2] and section 35.13 of the Commission's regulations,[3] the MISO Transmission Owners[4] filed revisions to the generic and company-specific

---

[1] *Midcontinent Independent System Operator, Inc.*, 150 FERC ¶ 61,004 (2015) (January 5 Order).

[2] 16 U.S.C. §§ 824e, 824s (2012).

[3] 18 C.F.R. § 35.13 (2014).

[4] The MISO Transmission Owners for the November 6 Filing consist of the following: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois; American Transmission Company LLC (ATC); Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; ITC Transmission (ITC); ITC Midwest LLC;
(continued…)

Attachment O formula rate templates of Midcontinent Independent System Operator, Inc.'s (MISO) Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to implement a 50-basis point adder (RTO Adder) to their authorized rate of return on equity (ROE), based on the MISO Transmission Owners' participation as members in a regional transmission organization (RTO).[5]

3. In the January 5 Order, the Commission granted the MISO Transmission Owners' request to implement the RTO Adder, subject to it being applied to a base ROE that has been shown to be just and reasonable based on an updated discounted cash-flow analysis and subject to the resulting ROE being within the zone of reasonableness determined by that updated discounted cash-flow analysis, as those may be determined in the pending complaint proceeding in Docket No. EL14-12-000 (Complaint Proceeding).[6] The Commission accepted the proposed Attachment O revisions for filing and suspended them for a nominal period, to become effective January 6, 2015, subject to refund, and subject to the outcome of the Complaint Proceeding.[7] The Commission also accepted the MISO Transmission Owners' request to defer collection of the RTO Adder pending the outcome of the Complaint Proceeding.[8]

4. In response to concerns raised by intervenors about the ability of MISO transmission owners who were not participants in the November 6 Filing to also implement the RTO Adder, the Commission held:

> Consistent with the way that the generally applicable MISO ROE is available for use by any MISO transmission owner, we affirm that the RTO

Michigan Electric Transmission Company, LLC (METC); MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Vectren Energy Delivery of Indiana; and Wolverine Power Supply Cooperative, Inc.

[5] MISO was also a party to the filing solely in its role as the administrator of its Tariff.

[6] January 5 Order, 150 FERC ¶ 61,004 at P 45 (citing *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049 (2014) (Complaint Hearing Order)).

[7] *Id.*

[8] *Id.* P 47.

> Adder would be available for use by any transmission-owning members of MISO that have turned operational control of their transmission system over to MISO and use the generally applicable MISO ROE, subject to the conditions concerning the base ROE and zone of reasonableness discussed above. However, those entities utilizing an Attachment O formula that has not been revised to reflect the RTO Adder in the instant proceeding will need to make a filing under section 205 to reflect the RTO Adder in their formula in order to be able to include the RTO Adder in rates that are calculated pursuant to their formula.[[9]]

II. Requests for Clarification and Rehearing

5. On February 4, 2015, Hoosier and Southern Illinois filed a motion for clarification or, in the alternative, rehearing of the January 5 Order. Hoosier and Southern Illinois state that they are MISO transmission owners that did not join in the November 6 Filing. They state that they are therefore directly affected by the Commission's determination that the RTO Adder should be available to all MISO transmission owners. However, as rural electric cooperatives that receive financing from the Rural Utilities Service, they state that neither Hoosier nor Southern Illinois is a public utility under section 201(f) of the FPA,[10] and thus neither is able to make a filing under section 205 of the FPA. Therefore, Hoosier and Southern Illinois seek clarification that the January 5 Order contemplated that a filing to implement the RTO Adder in the Attachment O formula of a non-jurisdictional transmission owner not included in the November 6 Filing would be submitted by MISO on behalf of that transmission owner, rather than by the transmission owner itself. In the alternative, if the Commission intended to require that entities utilizing an Attachment O formula must themselves make the section 205 filing, then Hoosier and Southern Illinois seek rehearing on the grounds that such a procedure would require an impossible act – submission of a filing pursuant to section 205 by an entity that is not a public utility – and would be unjust and unreasonable, and unduly discriminatory.[11]

---

[9] *Id.* P 48 (footnote omitted).

[10] 16 U.S.C. § 824(f) (2012).

[11] Hoosier and SPIC Motion for Clarification or Rehearing at 3-4. We note that on March 10, 2015, in Docket No. ER15-1210-000, MISO submitted in its role as administrator of the Tariff, on behalf of Hoosier and Southern Illinois pursuant to sections 205 and 219 of the FPA, a filing to seek Commission approval to implement a 50 basis-point RTO Adder to the authorized ROE for participation in MISO in the revenue requirements of Hoosier and Southern Illinois included in Attachment O-RUS Non-Levelized Generic Rate Formula Template under the MISO Tariff. On May 8,

(continued…)

6. On February 4, 2015, MISO Coalition filed a request for rehearing of the January 5 Order. MISO Coalition disputes the Commission's determination that the MISO Transmission Owners "need not provide additional justification as to the necessity of the incentive" and that, rather, they are "presumed eligible" for the incentive because they have already joined MISO and their membership is ongoing.[12] MISO Coalition states that the Commission rejected protestors' arguments, including those presented by MISO Coalition, that the RTO Adder would not yield consumer benefits. MISO Coalition states that, under section 205 of the FPA, the MISO Transmission Owners, as the filing parties, have the burden of proof to show that the proposed RTO Adder is just and reasonable. However, MISO Coalition contends that the Commission improperly shifted onto the protestors the burden of proof to demonstrate that the proposed RTO Adder is unjust and unreasonable because the proposal fails to yield the type of benefits contemplated by section 219 of the FPA.[13]

7. In addition, MISO Coalition argues that, based on the plain language of Order No. 679,[14] the MISO Transmission Owners were required to provide justification for their proposed RTO Adder, but they have failed to do so.[15] While the Commission noted that its approval of the RTO Adder for the MISO Transmission Owners was based on their commitment to continue being members of MISO, MISO Coalition asserts that there is no minimum commitment period and the January 5 Order does not require the MISO Transmission Owners to remain with MISO any longer than if the proposed RTO Adder had been rejected. MISO Coalition states that many of the MISO Transmission Owners have been MISO members for over a decade without ever receiving the incentive of an

---

2015, the Commission conditionally accepted Hoosier and Southern Illinois's March 10 filing, subject to a compliance filing. *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,104 (2015).

[12] MISO Coalition Request for Rehearing at 3 (citing January 5 Order, 150 FERC ¶ 61,004 at P 41).

[13] *Id.* at 3-4.

[14] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[15] MISO Coalition Request for Rehearing at 4 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326 (the Commission "will approve, *when justified*, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an . . . RTO.") (Emphasis supplied by MISO Coalition).

RTO Adder and, therefore, there is no threat that they would leave if they are unable to collect the RTO Adder.[16]

8. In addition, MISO Coalition argues that there must be a showing that the benefits and costs of incentives must be roughly proportional and that the MISO Transmission Owners have not demonstrated that the RTO Adder would yield benefits that are equal to or greater than the amount that customers would be required to pay if the Commission's approval of the RTO Adder is affirmed, i.e., approximately an additional $50 million annually, according to MISO Coalition. MISO Coalition contends that the RTO Adder is a large windfall for the MISO Transmission Owners with no realizable corresponding benefit.[17]

9. Finally, MISO Coalition disputes the January 5 Order's reliance on cases in which the Commission approved 50-basis point adders for RTO participation, arguing that the Commission must consider incentives on a case-by-case basis, and not on a generic basis, to fulfill its Congressional mandate.[18]

III. Discussion

10. We grant the motion for clarification by Hoosier and Southern Illinois. With respect to their concern, we clarify that where a MISO transmission owner is not subject to the Commission's jurisdiction under section 205 of the FPA, it does not need to make its own filing to request the revision to its Attachment O formula to implement the RTO Adder. It may instead rely upon MISO to make such a filing on its behalf.

11. We deny MISO Coalition's request for rehearing. First, the MISO Transmission Owners met their burden of proof under section 205 of the FPA. It is undisputed that the MISO Transmission Owners are members of MISO and have turned operational control of their transmission systems over to MISO, and it is undisputed that they made such showing.[19] The January 5 Order requires a showing that the resulting ROE with the ROE

---

[16] *Id.*

[17] *Id.* at 4-5.

[18] *Id.* at 5 (citing January 5 Order, 150 FERC ¶ 61,004 at n.100).

[19] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326 (any entity is eligible for the ROE incentive for RTO participation incentive if it can demonstrate that it has joined an RTO and that its membership is ongoing); Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86 (same). *See also, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,050, at P 23 (2015) (a utility must turn over operational control of its transmission facilities to an RTO, or in the case of MISO transmission owners'

(continued…)

Adder for RTO membership be just and reasonable, but granted a waiver of the necessity to provide cost support in this proceeding because issues related to the just and reasonable ROE are being addressed in the Complaint Proceeding.

12. Further, MISO Coalition's argument that there is no minimum commitment period for the MISO Transmission Owners to remain members of MISO is misplaced. No minimum commitment period is necessary. If a MISO Transmission Owner withdraws from MISO, it would no longer be eligible to receive an RTO Adder based on on-going membership in MISO.[20]

13. In addition, MISO Coalition's argument that the MISO Transmission Owners failed to show benefits commensurate with the costs of the RTO Adder overlooks that in Order No. 679-A, the Commission found that encouraging both new and continuing RTO membership provides reliability and cost benefits consistent with the statutory goals of section 219 of the FPA. The RTO Adder is not subject to a test that the public utility would not be a member of the RTO but for the incentive, as MISO Coalition suggests. Rather, in Order No. 679-A, the Commission determined as follows:

> We affirm the finding in the Final Rule that the incentive applies to all utilities joining transmission organizations, irrespective of the date they join, based on a reading of section 219 in its entirety. Section 219 specifically provides that "the Commission shall . . . provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." The stated purpose of section 219 is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power. We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented, and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective

---

transmission facilities that do not qualify for such transfer, provide service over such facilities through the MISO Tariff with MISO acting as agent pursuant to Appendix G of the Transmission Owners Agreement); *Northeast Transmission Development, LLC*, 135 FERC ¶ 61,244, at P 73 (2011); *Atlantic Grid Operations A LLC*, 135 FERC ¶ 61,144, at P 75 (2011).

[20] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 327 (requiring that membership in an RTO be "on-going" in order to be eligible for the RTO participation incentive).

> for the entire duration of a utility's membership in the Transmission Organization. To limit the incentive to only utilities yet to join Transmission Organizations offers no inducement to stay in these organizations for members with the option to withdraw, and hence risks reducing Transmission Organization membership and its attendant benefits to consumers. Because the incentive is applicable to utilities that join Transmission Organizations and is consistent with the requirements of section 219 of the FPA, the incentive complies with EPAct 2005 and the FPA.[[21]]

In making that determination, the Commission also explained that its approach was consistent with the goal of Order No. 2000.[22]

---

[21] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86.

[22] *Id.*:

> In Order No. 2000, in which the Commission's goal was to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service, the Commission stated that:
>
> > These benefits [of RTOs] will include: increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of [available transmission capacity]; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices. All of these improvements to the efficiencies in the transmission grid will help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.

(continued...)

14. Finally, the fact that entities request the same level of ROE Adder for RTO membership that other entities have been granted does not mean that granting such a request makes an RTO adder the Commission's "generic" adder. Indeed, in Order No. 679, the Commission declined to create a generic adder for such membership.[23] The Commission's granting of the requested 50-basis point ROE Adder for RTO membership is subject to it being applied to a base ROE that has been shown to be just and reasonable based on an updated discounted cash-flow analysis and subject to the resulting ROE being within the zone of reasonableness determined by that updated discounted cash-flow analysis. This is consistent with our determinations in other cases involving applicants for incentives, such as the cases cited in the January 5 Order.

The Commission orders:

(A) Hoosier and Southern Illinois's request for clarification is hereby granted, as discussed in the body of this order.

(B) MISO Coalition's request for rehearing is hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,024 [(1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001)].

[23] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326.

Document Content(s)

Appendix 16 – October 30, 2015 ITC Request for Attachment O Modifications
(Docket No. ER16-208)

STUNTZ, DAVIS & STAFFIER, P.C.
ATTORNEYS AT LAW

555 Twelfth Street, N.W.
Suite 630
Washington, D.C. 20004
(202) 638-6588 Telephone
(202) 638-6581 Facsimile

October 30, 2015

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: *International Transmission Company d/b/a ITCTransmission, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC*
Docket No. ER16-___-000

Via eTariff Filing

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] the Midcontinent Independent System Operator, Inc. ("MISO") and International Transmission Company d/b/a ITC*Transmission* ("ITCT"), Michigan Electric Transmission Company, LLC ("METC"), and ITC Midwest LLC ("ITC Midwest") (ITCT, METC and ITC Midwest are referred to collectively as "Joint Applicants") hereby propose modifications to certain aspects of the Joint Applicants' respective formula rate templates used in the calculation of charges for transmission service under Attachment O of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").[3] In addition, ITCT and ITC Midwest seek authorization pursuant to Order No. 618 for an amortization rate to be applied to intangible plant, and ITCT seeks authorization for a depreciation rate associated with transmission plant Account No. 355, Poles and Fixtures.

Attachment O of the MISO Tariff ("Attachment O") sets forth the forward looking formula rates under which Joint Applicants recover their respective annual revenue requirements and through which they establish charges for transmission service for facilities which they own that are under MISO's functional control. As described more fully below, this Application seeks changes to Joint Applicants' formula rate templates to:

---

[1] 16 U.S.C. § 824d (2014).
[2] 18 C.F.R. Part 35 (2014).
[3] MISO joins this filing solely as the administrator of its Tariff, but takes no position on the substance of this filing and reserves and the right to comment or protest.

1) recover income tax expense associated with permanent book/tax differences, the effects of after-tax accounting for deferred taxes associated with the equity component of the Allowance for Funds Used During Construction ("AFUDC equity"), and excess/deficient deferred income taxes resulting from tax law or rate changes; 2) exclude deferred income tax balances from the calculation of rate base when the associated income tax consequences have been paid by others; 3) explain how Joint Applicants will implement Internal Revenue Service ("IRS") guidance on tax normalization issues; and 4) propose changes in the allocators for materials and supplies ("M&S") and Regulatory Commission expenses. ITCT and ITC Midwest also seek Commission authorization for the use of a 2% amortization rate for intangible plant, and ITCT also seeks authorization to adopt a depreciation rate for Account No. 355 of 1.83%.

Joint Applicants request an effective date of January 1, 2016, for the proposed template changes and requested depreciation and amortization rates.

I. DESCRIPTION OF JOINT APPLICANTS

ITCT, METC and ITC Midwest are independent, stand-alone transmission companies engaged exclusively in the development, ownership and operation of facilities for the transmission of electric energy in interstate commerce. Each is a subsidiary of ITC Holdings Corp. ("ITC Holdings"), which invests exclusively in the electric power transmission grid to improve electric reliability, facilitate access to renewable and other generation, improve access to power markets, and reduce the overall cost of delivered electric power. The Joint Applicants all are Transmission Owner members of MISO. Transmission service over facilities developed and owned by the Joint Applicants is provided by MISO pursuant to the MISO Tariff.

II. BACKGROUND

Transmission Owners within MISO calculate their annual transmission revenue requirements pursuant to rate formulas set forth in Attachment O of the MISO Tariff. A number of these formulas are company-specific (including Joint Applicants') and include provisions approved by the Commission for use by individual Transmission Owners. The formulas are used to calculate an annual transmission revenue requirement for each Transmission Owner. These annual transmission revenue requirements are then used to calculate zonal rates for Firm and Non-Firm Point-To-Point Transmission Service provided under Schedules 7 and 8 of the MISO Tariff and Network Integration Transmission Service provided under Schedule 9 of the MISO Tariff.

Joint Applicants have determined that certain aspects of their respective Attachment O rate formulas require modification in order to ensure that total income tax expense is computed correctly in their revenue requirements, and to reflect IRS guidance. Additionally, it is necessary to establish an amortization rate for intangible plant for ITCT and ITC Midwest, and a depreciation rate for Account No. 355 for ITCT. Finally, changes in the allocators used for M&S and Regulatory Commission expenses also are required.

III. DESCRIPTION OF PROPOSED TARIFF REVISIONS

Joint Applicants have identified modifications to their Attachment O formula rate templates necessary to ensure that their revenue requirements and rates derived therefrom accurately reflect the costs of providing transmission service. First, all three Joint Applicants' Attachment O templates require two additional income tax-related line items to compute the effect on Joint Applicants' income tax expense associated with: 1) permanent book/tax differences and the effects of after-tax accounting for deferred taxes associated with AFUDC equity; and 2) excess/deficient deferred income taxes that result from changes to income tax laws, income tax rates or other action taken by a taxing authority. Second, the Joint Applicants seek an adjustment to Note F of their Attachment O templates to exclude from rate base accumulated deferred income tax balances when the associated income tax consequences have been paid by others. Joint Applicants also seek an additional revision to Note F to their Attachment O templates to reflect IRS guidance on specific tax normalization issues. Finally, Joint Applicants propose changes in the allocators used for M&S and Regulatory Commission expenses.

In addition to these changes to the Attachment O templates, the Application seeks approval for a 2% amortization rate for intangible plant recorded in Account No. 303 for both accounting and rate purposes for ITCT and ITC Midwest. This is consistent with the amortization rate for Account No. 303 already in effect for METC.[4] ITCT also seeks authorization to adopt a depreciation rate for Account No. 355. A table showing the depreciation rates will be reflected in separate rate schedules following each of the Joint Applicants' Attachment O templates.

A. Changes To The Joint Applicants' Formula Rate Templates In Attachment O Of The MISO Tariff

1. Income Tax-Related Changes

The Joint Applicants' formula rates are to be calculated to permit the Joint Applicants to recover their permitted return on equity after income taxes. Two changes to the Joint Applicants' formula rate templates are required in order to achieve this result, consistent with Commission-approved formula rate templates of other MISO Transmission Owners.

a. Attachment O Template: Excess/Deficient Deferred Income Taxes Changes

Actions taken by taxing authorities have resulted in excess/deficient deferred income taxes at the Joint Applicants. For example, Michigan enacted a new Corporate Income Tax that replaced the Michigan Business Tax in 2011. ITCT and METC have increased their Michigan accumulated deferred income tax balances to reflect this change (credit) and recorded a regulatory asset (debit) reflecting the probable future revenue

---

[4] Depreciation rates for METC were approved by letter order issued in Docket No. ER10-185-000 on Dec. 18, 2009.

impact of allowing for the income tax changes to be recovered. Recovery of the effects of income tax law or rate changes is consistent with the Commission's position on income tax rate changes. *See* Order No. 144,[5] in which the Commission concluded that it is appropriate to adjust revenue requirements for the effects of tax law or rate changes over time. In *Accounting for Income Taxes*, Chief Accountant's Guidance in Docket No. AI93-5-000 (April 23, 1993)("AI93-5-000 Guidance"), the Chief Accountant explained that:

> Order No. 144 requires an entity to compute the income tax component in its cost of service by making provision for any excess or deficiency in deferred taxes under the following circumstances: (1) if the entity has not provided deferred taxes in the same amount that would have accrued had tax normalization been applied for tax effects of timing difference transactions originating at any time prior to the test period; or (2) if, as a result of changes in tax rates, the accumulated provision for deferred taxes becomes deficient in or in excess of amounts necessary to meet future tax liabilities as determined by application of the current tax rate to all timing difference transactions originating in the test period and prior to the test period.[6]

The Chief Accountant advised further that to record the effect of a change in tax law or rates,

> [t]he entity shall adjust its deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted. The adjustment shall be recorded in the proper deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts. If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3, Other Regulatory Assets, or Account 254, Other Regulatory Liabilities, as appropriate, for that probable future revenue or reduction in future revenue. That asset or liability is also a temporary difference for which a deferred tax asset or liability shall be recognized in Account 190, Accumulated Deferred Income Taxes or Account 283, Accumulated Deferred Income Taxes – Other, as appropriate.[7]

To provide for the recovery of the effect of income tax rate changes or other actions taken by a governmental authority resulting in excess/deficient deferred income taxes, the Joint Applicants' current templates need to be adjusted to permit amortization of the tax law or rate change differential to be included in the income tax calculation for their formula rates. A new line 24a, "(Excess)/Deficient Deferred Income Taxes," and a new line 26a, "(Excess)/Deficient Deferred Income Tax Adjustment," will be added to page 3 of the

[5] *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, 15 FERC ¶ 61,133 (1981), FERC Stats. and Regs. ¶ 30,254 (1981).
[6] AI93-5-000 Guidance, at p. 2.
[7] *Id.*, at p. 8.

Attachment O templates for each Joint Applicant, similar to the treatment of such deferred taxes for other MISO Transmission Owners.[8]

In addition, a new Note AB[9] would be added to explain line 24a: "Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a)."

ITCT and METC will amortize, to the new line 24a, the deficient deferred state income taxes resulting from the 2011 Michigan Corporate Income Tax change beginning in 2016 over the remaining book lives of the property giving rise to the deferred income tax. ITCT and METC will calculate the remaining book lives of the assets associated with the Michigan Corporate Income Tax change,[10] using inputs from the applicable FERC Form No. 1. The calculation of the remaining useful life of the property giving rise to the deferred income tax, as well as the annual amortization amount that will be populated in the new line 24a for ITCT and METC, respectively, each year through the end of the respective amortization period is provided in Exhibit 1.

In addition to the Michigan Corporate Income Tax change, Joint Applicants anticipate that there will be other sources of excess/deficient deferred state income taxes. In the case of ITC Midwest, a multi-state operating company, the state tax rate for income taxes may change each year due to the effect of enacted state tax laws or any changes in ITC Midwest's level of activity that may affect the state tax apportionment among states. The deferred income tax assets and liabilities are remeasured to reflect these changes in ITC Midwest's state income tax rate. Such remeasurements result in excess/deficient deferred income taxes. As recent examples of state tax law changes resulting in state income tax rate changes, Minnesota enacted a tax law utilizing a single-factor apportionment formula based solely on the sales factor (in contrast to the previous three-factor apportionment method), which was phased in during the tax years 2007 through 2014, and the Illinois income tax rate was reduced beginning with the 2015 tax year.

Because the amounts have been insignificant, ITC Midwest has not recognized regulatory assets or regulatory liabilities associated with ITC Midwest's historical excess/deficient deferred income taxes, as was done at ITCT and METC associated with the 2011 Michigan Corporate Income Tax change. The estimated amount of historical net

---

[8] *See* American Transmission Company ("ATC") Rate Formula Template, page 3, line 24a, "Excess Deferred Income Taxes (enter negative)," and line 26a, "Excess Deferred Income Tax Adjustment"; DATC Midwest Holdings, LLC ("DATC") Attachment O Template as approved in Docket No. ER12-1593-000, page 3, line 38, "Excess Deferred Income Taxes" and line 42, "Excess Deferred Income Tax Adjustment."

[9] The note in the METC Attachment O template will be Note CC.

[10] Had amortization begun on January 1, 2012, the amortization period for ITCT and METC would have been 27 and 36 years, respectively. Since amortization will not begin until January 1, 2016, the remaining life is 23 years for ITCT and 32 years for METC. By using an amortization period of 23 years for ITCT and 32 years for METC beginning in 2016, the excess deferred income taxes are fully recovered in the same time frame over which the underlying property is depreciated.

deficient deferred income taxes at ITC Midwest is approximately $200,000; ITC Midwest is not proposing to recover these amounts. If this filing is approved, ITC Midwest will begin to recognize regulatory assets and regulatory liabilities associated with newly originating excess/deficient deferred income taxes in 2016.

The Joint Applicants will amortize, to the new line 24a, the excess/deficient deferred state income taxes resulting from state tax rate changes due to the effect of enacted state tax laws or any changes in each respective Joint Applicant's level of activity that may affect state tax apportionment among states. The excess/deficient deferred state income taxes will be amortized over the remaining book lives of the property giving rise to the deferred income tax, as demonstrated in the Michigan Corporate Income Tax change example above. The annual amortization amount will be populated in the new line 24a, and the Joint Applicants will include a workpaper in each annual formula rate posting that identifies and describes the amount of any excess/deficient deferred state income taxes being amortized.

The Joint Applicants currently do not have any excess/deficient deferred income taxes associated with federal income taxes. Any future excess/deficient deferred federal income taxes associated with a change to the federal income tax law or rates will follow an amortization method that is permitted under the normalization provisions of the Internal Revenue Code ("IRC"). For example, in connection with the last federal income tax rate decrease, the IRS provided guidance on the use of either the average rate assumption method ("ARAM") or the Reverse South Georgia Method ("RSGM") to amortize the excess deferred income tax under the transition provisions of the Tax Reform Act of 1986. Under ARAM or RSGM, the "excess" deferred income taxes applicable to certain depreciation-related temporary differences cannot be used to reduce cost of service rates any more rapidly than over the book lives of the property giving rise to the deferred tax.

b. Attachment O Template: Recovery For The Income Taxes On Permanent Differences And The Effects Of After-Tax Accounting For Deferred Taxes Associated With AFUDC Equity

Certain items of revenue and expense are treated differently for financial reporting than they are for income tax purposes. For example, federal income tax rules do not permit the deduction on the income tax return of the AFUDC equity that is capitalized to plant and included in depreciation expense for financial reporting purposes. Thus, over time, the financial statement reporting of depreciation expense, which includes a component for book basis of AFUDC equity, will be different from the related amount deducted on the income tax return that does not include AFUDC equity.

In Order No. 144-A, the Commission recognized that AFUDC equity requires adjustment in the income tax calculation:

> It was the intention in Order No. 144 to require the normalization of the difference between straight-line depreciation used for rate purposes (as adjusted for

permanence differences such as equity AFUDC) and aggregate straight-line tax depreciation.[11]

Additionally, in the AI93-5-000 Guidance the Chief Accountant acknowledged that income tax related regulatory asset accounts needed to be considered associated with this AFUDC equity income tax difference:

> [a]n entity shall record the deferred tax liability for the equity component of AFUDC in Account 282, Accumulated Deferred Income Taxes – Other Property, and any corresponding regulatory asset in Account 182.3, Other Regulatory Assets. The regulatory asset is itself a temporary difference for which deferred incomes taxes shall be recognized and recorded in Account 283, Accumulated Deferred Income Taxes – Other. This accounting shall be followed for the adjustments required upon initial application of the statement and for all amounts of equity AFUDC capitalized in subsequent periods.[12]

In addition to AFUDC equity that is treated differently for financial reporting than for income tax purposes, permanent differences also exist or may arise. Deferred income taxes are not required on permanent differences. In Order No. 144, the Commission made it clear that permanent differences do not require deferred taxes:

> [p]ermanent differences (in ratemaking) are differences between the amounts of expenses or revenues recognized in one period for income tax purposes and for ratemaking which do not reverse or turn around in one or more other periods. The final rule is not applicable to permanent difference transactions. It requires tax normalization only for timing difference transactions.[13]

Therefore, in the case of permanent differences involving recoverable expenses, the current income taxes reported on the financial statements are adjusted to reflect the non-deductibility of these expenses and there is no offsetting deferred income tax adjustment, as such costs are not deducted on the income tax return. Similarly, adjustments to decrease current income taxes for income items that will never be included in taxable income will be made without an off-setting deferred income tax adjustment. As a result, the income tax effects of permanent differences increase or decrease income tax expense for financial reporting purposes.[14]

Similar to the treatment for financial reporting purposes, the income tax effects of permanent differences associated with items included in the calculation of revenue requirement should increase or decrease the amount of income tax expense used for ratemaking.

---

[11] Order No. 144-A, FERC Stats. and Regs. ¶ 30,340, p. 30,136 (1982).
[12] AI93-5-000 Guidance, p. 6.
[13] Order No. 144, FERC Stats. and Regs. ¶ 30,254, p. 31,538.
[14] In contrast, for temporary differences, each item that impacts current income tax expense has an equal and offsetting impact to deferred income tax expense.

For the Joint Applicants to recover in revenues the income tax effects of items treated as permanent differences, as well as AFUDC equity, these items need to be added when determining income tax expense under a method that bases the income tax expense calculation on the allowed return (such as the method used in determining tax expense for the Joint Applicants' formula rates). Therefore, the effect on the income tax expense component of revenue requirement will equal permanent differences and the portion of depreciation expense associated with AFUDC equity multiplied by T/(1-T), where "T" is the tax rate included on page 3, line 21 of the Attachment O templates.

An adjustment to the income tax calculation in the Attachment O templates for each of the Joint Applicants therefore is necessary to provide for recovery of permanent income tax differences that are associated with items that are included in the Attachment O revenue requirement, as well as for the effects of after-tax accounting for deferred taxes associated with AFUDC equity.[15] This would be accomplished by adding a new line 24b, "Tax Effect of Permanent Differences and AFUDC Equity," and a new line 26b, "Permanent Differences and AFUDC Equity Tax Adjustment," to page 3 of the Attachment O templates for each company. The addition of these lines would be consistent with the treatment of permanent differences in the formula rate templates of other MISO Transmission Owners.[16]

Additionally, a new Note AC[17] would be added to explain the amounts included in line 24b: "Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b)." The Joint Applicants also will include a workpaper in each annual formula rate posting that identifies permanent differences and depreciation expense associated with AFUDC equity and calculates the inputs to line 24a by multiplying such amounts by T.

---

[15] Although AFUDC equity is commonly referred to as a permanent difference as a result of language appearing in Order No. 144, it is more appropriate since the advent of Financial Accounting Standard 109 *Accounting for Income Taxes* (now Accounting Standards Codification 740 *Accounting for Income Taxes*) to refer to AFUDC equity as a temporary difference that arises in a below-the-line other income account and reverses in an above-the-line operating expense account (*i.e.*, depreciation expense).

[16] *See* ATC Rate Formula Template, page 3, line 24b, "Tax Affect [sic] of Permanent Difference," and line 26b, "Permanent Differences Tax Adjustment Similar lines are included on lines 39 and 43 of page 3 of the Attachment O template approved for DATC in Docket No. ER12-1593-000.

[17] The note in the METC Attachment O template will be Note DD.

2. Exclusion of Deferred Income Taxes from Rate Base When the Associated Income Tax Consequences Have Been Paid By Others

The Joint Applicants may receive Contributions in Aid of Construction ("CIAC") from others for any projects where the MISO Tariff provides for participant funding. Receipt of the CIAC reduces the Joint Applicants' plant balances for the related facilities. Therefore, the return on and of the plant cost of the facilities subject to the CIAC is not included in the Attachment O formula. However, certain CIAC arrangements also result in adverse tax consequences to the Joint Applicants. For example, the Joint Applicants have indemnification rights under MISO's standard interconnection agreement to charge an interconnection customer for these tax consequences. The Joint Applicants have charged generators a tax gross up for the income tax consequences associated with their CIAC.

Joint Applicants have determined that ADIT associated with these tax consequences is included in rate base under the existing Attachment O template. To address this, the Joint Applicants propose an adjustment to the Attachment O template to exclude certain ADIT balances from rate base when the associated tax consequences have been paid for by others. Note F would be revised to include the following: "Exclude ADIT balances when the associated income tax consequences have been paid by others." Adequate recovery of the tax consequences associated with CIACs is received from the contributors; an additional return as part of the revenue requirement is not necessary.

As shown in Exhibit 3, this change will result in a reduction in the projected 2016 gross revenue requirement of $68,350 (ITCT), $84,385 (METC) and $1,397,496 (ITC Midwest). Joint Applicants also will refund to customers the return received on CIAC-related ADIT amounts previously collected under Attachment O for the period 2004-2014, with interest, as part of their 2016 formula rate projections, to be re-calculated and re-posted upon Commission acceptance of this filing. Joint Applicants will include a refund calculation workpaper with their reposted 2016 formula rate projections. These refunds will result in a return to customers of $1,128,225 (for ITCT), $593,936 (for METC) and $6,564,590 (for ITC Midwest), inclusive of interest. Finally, the return on CIAC-related ADIT amounts collected through rates in 2015, with interest, will be refunded through the 2015 true-up calculated in June, 2016, and reflected in the 2017 rates. Estimated 2015 amounts to be refunded to customers, with interest, based on 2015 projections are $83,724 (for ITCT), $100,482 (for METC) and $1,682,842 (for ITC Midwest); actual amounts to be refunded will be based on 2015 actuals.

3. IRS Normalization Rules

The Commission requires that public utilities use normalization methods of accounting. In general, the Joint Applicants calculate deferred tax balances using beginning and year end balances, or as otherwise required by the IRS.

In October 2014, each of the Joint Applicants sought a private letter ruling from the IRS on the consequences under the normalization provisions of the Joint Applicants' use of Commission-approved formula rates. In particular, Joint Applicants sought a ruling that the computation of average rate base with reference to 13-month averages for plant and accumulated depreciation and a simple averaging of the beginning- and end-of-year balances for accumulated deferred income taxes complies with the consistency requirement of the normalization rules for accelerated depreciation under section 168(i)(9)(B) of the IRC.

In Private Letter Rulings 201531010 (ITCT), 201531011 (METC) and 201531012 (ITC Midwest) ("the PLR" or "the PLRs"),[18] the IRS determined that satisfying the requirements of section 168(i)(9)(B) requires that there be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense and deferred tax revenue purposes. The IRS found that rate base, depreciation expense and accumulated deferred income taxes are all averaged over the same period and are calculated in a consistent fashion by the Joint Applicants. The IRS therefore ruled, as requested, that the calculation of average rate base and accumulated deferred income taxes by the Joint Applicants pursuant to their Attachment O formula rates complies with the consistency requirements of IRC section 168(i)(9)(B).

The Joint Applicants also sought a ruling regarding whether the computation of accumulated deferred income taxes for purposes of calculating average rate base without applying the proration formula for future test periods under section 1.167(l)-1(h)(6) of the Income Tax Regulations complies with the normalization requirements of IRC section 168(i)(9). The IRS in the PLRs determined that the Joint Applicants are required to apply the proration formula in calculating accumulated deferred income taxes included in rate base for the purpose of establishing the projected rate. However, the IRS in the PLRs determined that the Joint Applicants are not required to apply the proration formula in calculating accumulated deferred income taxes included in rate base for the purpose of calculating actual revenue requirement used to determine the true-up.

Joint Applicants are proposing to revise Note F to their Attachment O templates to explain that the Joint Applicants will apply proration in a manner consistent with the direction received from the IRS. Note F, as revised, will read as follows: "The calculation of ADIT in the annual true-up calculation will use the beginning-of-year and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6)."

In applying the proration formula, instead of averaging the beginning-of-year and end-of-year balances, the Joint Applicants will include a workpaper in each projected annual formula rate showing the calculations under the proration formula along with a reference to the applicable IRS private letter ruling indicating the requirement to use the proration formula. An example of such a workpaper, taken from the METC 2016 rate projection posting,[19] is presented in Exhibit 2.

---

[18] *See, e.g.*, http://www.irs.gov/pub/irs-wd/201531011.pdf.
[19] *See* http://www.oasis.oati.com/woa/docs/METC/METCdocs/114METC_2016_Projected_Rate_Reporting.html, file no. 8 (Attachment O workpapers), posted August 31, 2015.

4. Change in M&S and Regulatory Expense Allocators

The Joint Applicants require two changes in the allocators used in the generic MISO Attachment O template to ensure proper recovery of certain costs.

Under the Joint Applicants' existing Attachment O formula rate templates, and as provided in the generic MISO Attachment O template, in calculating rate base, the TE ("Transmission Expense") allocator is applied to the M&S amount shown on line 27 of page 2. The TE allocator is used in Attachment O primarily to reduce Transmission O&M expense recovery to account for expenses recovered under ancillary services rates. For the Joint Applicants, these are costs recovered under Schedule 1 and Schedule 24. Using the TE allocator for M&S is inappropriate because neither Schedule 1 or Schedule 24 includes the M&S amount currently excluded from recovery in Attachment O.

A change also is required with respect to the treatment of regulatory expenses. Joint Applicants' templates (p. 3, line 5 and Note I) require that EPRI Annual Membership Dues (shown in the Form 1 at 353.f), all Regulatory Commission expenses (itemized in the Form 1 at line 351.h) and non-safety advertising included in Account 930.1 be deducted from A&G when calculating Total O&M. Transmission Related Regulatory Commission Expense is then added back on line 5a; per note I, this includes Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission siting (as itemized at 351.h of the Form 1).

Joint Applicants' templates apply the TE allocator to the Transmission Related Regulatory Commission Expenses added in on line 5a. However, since no Regulatory Commission expenses are recovered in Schedule 1 and Schedule 24, the use of the TE allocator for this item results in under-recovery of transmission-related Regulatory Commission expenses.

Joint Applicants propose to use the TP allocator in place of the TE allocator for M&S and for transmission-related Regulatory Commission expenses to ensure the appropriate recovery of these expenses in Attachment O rates.

B. Depreciation And Amortization Rates

The Commission recognized in Order No. 618[20] that utilities should use appropriate methods of depreciation to "allocate in a systematic and rational manner the cost of property to the periods during which the property is used in utility operations, *i.e.*, over its estimated useful service life."[21] Utilities need not seek prior approval for revised depreciation rates for accounting purposes but must obtain Commission authorization "[t]o change prices charged for power sales or transmission services (whether determined by stated rates or formula rates) to reflect a change in depreciation."[22]

[20] *Depreciation Accounting*, Order No. 618, FERC Stats and Regs, Regulations Preambles ¶ 31,104 (2000).
[21] Order No. 618, Regulations Preambles ¶ 31,104, p. 31,694.
[22] *Id.*, p. 31,695 fn.25.

I. Intangible Plant Amortization Rates For ITCT And ITC Midwest

Under their current Attachment O formula rate templates, ITCT and ITC Midwest currently recover a "return on," but not a "return of," intangible plant. Because ITCT and ITC Midwest do not have a Commission-authorized amortization rate for intangible plant recorded to Account No. 303, the amortization expense is recorded to Account No. 425, which is not included in the Attachment O revenue requirement. However, return of intangible plant through use of amortization rates on intangible assets already is provided for under the Attachment O formula rates of other MISO Transmission Owners.[23] For example, METC has a Commission authorized amortization rate for Account No. 303 allowing the amortization expense to be recorded to Account No. 404, which is included in the Attachment O revenue requirement.

Consistent with the Commission's requirements for depreciation accounting under Order No. 618, ITCT and ITC Midwest request authorization to use a 2% amortization rate for both accounting and rate purposes for amounts recorded in FERC Account No. 303. The amounts recorded in Account No. 303 for ITCT and ITC Midwest result primarily from contributions made by ITCT or ITC Midwest to other utilities for facilities – generally transmission plant – that will be owned by the recipient utility. The amortization rate should be representative of the long life of such transmission plant. The proposed 2% amortization rate reflects the approximately 50-year useful life of the transmission plant, and is comparable to the depreciation rate previously approved by the Commission for METC intangible transmission plant.[24] A table showing the proposed depreciation accrual rates for intangible plant, as well as the previously approved depreciation rates for ITCT and ITC Midwest, will be reflected in separate rate schedules following the revised Attachment O formula rate templates for ITCT and ITC Midwest on sheets 14A and 17A, respectively.[25]

Contributions to other utilities for modifications to facilities owned by those utilities will initially be recorded to Account No. 107. Those contributions will be transferred to plant in service classified under Plant Account No. 303 only when the facilities associated with those contributions are placed in operation or are completed and ready for service.

ITCT and ITC Midwest will use Account 404, *Amortization of Limited-Term Electric Plant*, to record the annual amortization expense associated with the intangible plant recorded in Account 303. The use of Account 404 is consistent with Commission policy. The costs ITCT and ITC Midwest will incur for intangible plant would primarily

---

[23] *See, e.g.*, Minnesota Power Depreciation Rates-Transmission; American Transmission Company Depreciation Rates.

[24] *Michigan Electric Transmission Company, LLC*, Docket No. ER10-185-000, Letter Order, Dec. 18, 2009 (rate for intangible plant of 2.09%).

[25] No changes are proposed to the currently-effective METC depreciation rates; a new table showing METC's depreciation rates will be reflected in a separate rate schedule following the METC Attachment O formula rate template on sheet 15A.

be related to contributions to other utilities for modifications to facilities owned by those utilities. Those contributions will be similar to CIACs. "[T]he Commission treats a CIAC different from other amounts includable in intangible plant which may not have a terminable life, like goodwill."[26] Thus Commission policy requires that a CIAC be amortized to an account for other limited-term plant, Account 404.3, *Amortization of Other Limited-Term Gas Plant*, under Part 201, or Account 404, *Amortization of Limited-Term Electric Plant*, under Part 101.[27]

With respect to the proposed 2% amortization rate for Account No 303, the recovery of amortization expense will be provided for in the formula rate template for ITCT and ITC Midwest effective January 1, 2016, and the actual amount of amortization expense would be recognized in the FERC Form 1. The amortization rate would be applied on a straight line basis similarly to how depreciation rates are applied. Thus, if the average plant in service balance were $1 million, the resulting effect on annual amortization expense would be $20,000.

2. ITCT Depreciation Rate For Account No. 355

Depreciation rates for ITCT were approved in *International Transmission Company*, Docket No. ER09-1530-000, Letter Order issued Sept. 22, 2009. The Depreciation Rate Study ("Depreciation Rate Study") for ITCT filed with the Commission in that docket contained a depreciation rate for Account 354. In the Commission's Electric Plant Chart of Accounts, Account No. 354 is defined as "Towers and Fixtures," and Account No. 355 is defined as "Poles and Fixtures." In the Depreciation Rate Study, however, Account No. 354 depreciation rates were determined using both poles and towers, as well as related fixtures. The Depreciation Rate Study contained a depreciation rate of 1.37% for Account No. 354.[28] The Depreciation Rate Study did not recommend a depreciation rate for ITCT for Account No. 355, Poles and Fixtures.

ITCT has accounted for poles in Account No. 354 based on how the assets were transferred to ITCT as recorded by their former owner, and no distinction has been made between towers and poles when classifying between transmission plant accounts. However, the better classification within transmission plant would be to record new additions of poles and related fixtures in Account No. 355. Therefore, ITCT requests authorization to use a 1.83% depreciation rate for both accounting and rate purposes for amounts recorded in FERC Account No. 355. The 1.83% depreciation rate was derived

---

[26] *Williston Basin Interstate Pipeline Company*, Docket No. AC05-68-000, Letter Order, Dec. 27, 2006, at p. 1.

[27] *Id.*, *citing American Transmission Company*, Docket No. AC04-100-000, Letter Order, Jan. 24, 2005; *Kern River Gas Transmission Company*, 99 FERC ¶ 61,085 (2002); *Kern River Gas Transmission Company*, 98 FERC ¶ 61,205 (2002); *Georgia Strait Crossing Pipeline LP*, 98 FERC ¶ 61,271 (2002); *Horizon Pipeline Company*, L.L.C., 92 FERC ¶ 61,205 (2000).

[28] The Depreciation Rate Study on which ITCT's current depreciation rate for Account No. 354 was based analyzed poles and towers together to come up with the 1.37% rate.

based on the same useful life and net salvage ratio utilized for Account No. 354 of 60 years and -10%, respectively, as discussed in the Depreciation Rate Study.[29]

IV. INFORMATION REQUIRED BY THE COMMISSION'S REGULATIONS AND REQUEST FOR WAIVERS

A. Documents Submitted With This Filing (Section 35.13(b)(1))

This filing consists of the following documents:

1. This transmittal letter and accompanying Exhibits 1-3; and
2. Redline and clean versions of the proposed revisions to the Attachment O formula rate templates of each of the Joint Applicants, as well as separate rate schedules showing Depreciation Rates for each company[30].

B. Effective Date (Section 35.13(b)(2))

Joint Applicants request an effective date of January 1, 2016 for the changes to the Attachment O formula rate templates.

C. Service (Section 35.13(b)(3))

In accordance with Section 35.2(e) of the Commission's regulations, MISO has served a copy of this filing, including attachments, electronically on all Tariff Customers under the MISO Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the MISO Advisory Committee participants, as well as state commissions within the MISO region and the Organization of MISO States. In addition, the filing has been posted electronically on the MISO's website at www.misoenergy.org for other parties interested in this matter.

D. Description Of Rate Change (Section 35.13(b)(4))

The basis for the requested rate formula changes is described above in Section III.

E. Statement Of Reasons For Rate Change (Section 35.13(b)(5))

See Section III, above.

---

[29] *See* Depreciation Rate Study, p. 16. The proposed depreciation rate for Account No. 355 is calculated as following (1 – net salvage ratio)/useful life or (1-10%)/60=1.83%, utilizing the same useful life and salvage ratio for Account No. 354 as in the Depreciation Rate Study.

[30] Language currently pending before the Commission in an unrelated docket, ER15-945-001, is highlighted in yellow on the ITC Midwest template. MISO requests that the Commission treat such highlighted language as subject to the outcome of that proceeding. MISO commits to file any revisions to the highlighted language as necessary to comply with any Commission orders in Docket No. ER15-945-001.

F. Requisite Agreements For Rate Change (Section 35.13(b)(6))

Joint Applicants are not required to obtain prior agreement from other parties for the submission of this filing.

G. Statement Regarding Illegal, Duplicative, Or Unnecessary Costs (Section 35.13(b)(7))

None of the costs relating to this filing have been alleged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory practices.

H. Effect On Rates

The table shown in Exhibit 3 below presents the anticipated effects on 2016 revenue requirements of the proposed changes to the formula rate template.

I. Waivers

Joint Applicants request waiver of any requirements set forth in 18 C.F.R. Part 35 to the extent necessary to permit the Commission to accept this filing.

V. COMMUNICATIONS

All communications and correspondence with respect to this request and to this proceeding in general should be served upon the following individuals:

*Stephen J. Videto
Amy Monopoli
ITC Holdings Corp.
27175 Energy Way, Sixth Floor
Novi, MI 48377
T: (248) 946-3526
svideto@itctransco.com

*Linda G. Stuntz
Ellen S. Young
Stuntz, Davis & Staffier, P.C.
555 Twelfth Street, NW, Suite 630
Washington, DC 20004
T: (202) 638-6588
lstuntz@sdsatty.com

Individuals designated for inclusion on the official service list compiled by the Secretary of the Commission in this proceeding are indicated with an asterisk.

VI. CONCLUSION

Joint Applicants respectfully request that the Commission accept the above-described changes to their MISO Attachment O formula rate templates, effective as requested.

Respectfully submitted,

/s/: Ellen S. Young

Linda G. Stuntz
Ellen S. Young
Stuntz, Davis & Staffier, P.C.
555 Twelfth Street, NW, Suite 630
Washington, DC 20004
T: (202) 638-6588
eyoung@sdsatty.com

Counsel to International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC and ITC Midwest LLC

EXHIBIT 1

Exhibit 1
Docket No. ER16-__-000

ITCT and METC 2011 Michigan Corporate Income Tax Deficient Deferred Income Tax Amortization Calculation

	ITCT Total Electric Plant	METC Total Electric Plant	Source:
Total Electric Plant in Service	1,595,444,131	1,099,463,497	2011 Form No. 1, p. 207, line 104g
Total Accumulated Provision for Depreciation of Electric Utility Plant	(601,974,078)	(334,093,294)	2011 Form No. 1, p. 219, line 29c
Net Electric Plant in Service	993,470,053	765,370,203	
Total Depreciation Expense of Electric Plant	36,386,904	21,100,339	2011 Form No. 1, p. 336, line 12f
Average Remaining Useful Life (years) as of January 1, 2012	27	36	Net Plant divided by Depreciation Expense
Average Remaining Useful Life (years) as of January 1, 2016	23	32	

	ITCT	METC	
Michigan CIT Regulatory Asset	2,892,505	2,526,825	Principal amount to be recovered
	23	32	Recovery Period (years)
	125,761	78,963	Attachment O Template Line 24a Annual Amortization Amount

EXHIBIT 2

Exhibit 2
Docket No. ER16-__-000

2016 METC Rate Projection
Page 2 of 5
Line 20 : Deferred Taxes (282)
Adjustments to Rate Base

	Averaging without Proration		Averaging with Proration			
	Monthly Activity *	Balance *	# of Days Prorated	Calendar Days	Prorated Activity	Prorated Balance and Monthly Average
January 1, 2016		(178,534,662)				(178,534,662)
January 31, 2016	(2,096,198)	(180,630,860)	335	365	(1,923,908)	(180,458,570)
February 28, 2016	(2,096,198)	(182,727,058)	307	365	(1,763,104)	(182,221,673)
March 31, 2016	(2,096,198)	(184,823,256)	276	365	(1,585,070)	(183,806,744)
April 30, 2016	(2,096,198)	(186,919,454)	246	365	(1,412,780)	(185,219,524)
May 31, 2016	(2,096,198)	(189,015,652)	215	365	(1,234,747)	(186,454,270)
June 30, 2016	(2,096,198)	(191,111,850)	185	365	(1,062,457)	(187,516,727)
July 31, 2016	(2,096,198)	(193,208,048)	154	365	(884,423)	(188,401,150)
August 31, 2016	(2,096,198)	(195,304,246)	123	365	(706,390)	(189,107,540)
September 30, 2016	(2,096,198)	(197,400,444)	93	365	(534,100)	(189,641,640)
October 31, 2016	(2,096,198)	(199,496,642)	62	365	(356,067)	(189,997,706)
November 30, 2016	(2,096,198)	(201,592,840)	32	365	(183,776)	(190,181,483)
December 31, 2016	(2,283,198)	(203,876,038)	1	365	(6,255)	(190,187,738)
					Sum	(2,421,729,427)
					Average *	(186,286,879)

* Pursuant to the Internal Revenue Service ("IRS") private letter ruling 201531011, the accumulated deferred income taxes included in page 2 line 20 of the formula rate template is calculated in accordance with the proration formula prescribed by IRS regulation section 1.167(l)-1(h)(6) for the purpose of calculating revenue requirement for the projected rate period.

EXHIBIT 3

Exhibit 3
Docket No. ER16-____-000

Summary of 2016 Gross Revenue Requirement Impacts

Gross Revenue Requirement:	ITCMW	ITCT	METC	Total
Projected (no changes)	$ 419,666,755	$ 428,914,949	$ 329,417,368	$ 1,177,999,072
Consolidated Total Changes				
Intangible Plant Amortization Rate	$ 35,609	$ 10,602	$ -	$ 46,211
Excess/Deficient Deferred Income Taxes	$ 2,170	$ 205,828	$ 129,236	$ 337,234
AFUDC Equity	$ 884,200	$ 1,088,054	$ 420,394	$ 2,392,648
CIAC	$ (1,397,496)	$ (68,350)	$ (84,385)	$ (1,550,231)
Allocators	$ 707,343	$ 658,107	$ 477,039	$ 1,842,489
Total Changes	$ 231,826	$ 1,894,241	$ 942,284	$ 3,068,351
Revised Gross Revenue Requirement	$ 419,898,581	$ 430,809,190	$ 330,359,652	$ 1,181,067,423
Change in Gross Revenue Requirement	$ 231,826	$ 1,894,241	$ 942,284	$ 3,068,351
Attachment O Change	$ 186,056	$ 1,236,676	$ 676,561	$ 2,099,293
Attachment MM Change	$ 21,377	$ 552,709	$ 248	$ 574,334
Attachment GG Change	$ 24,393	$ 104,856	$ 265,475	$ 394,724
Total Change	$ 231,826	$ 1,894,241	$ 942,284	$ 3,068,351

MARKED TARIFF

Exhibit B-4

Attachment O-ITC

Page 1 of 56
Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/__

International Transmission Company

Line No.		(1)	(2)		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)		12 months		$0	$0	$0
	REVENUE CREDITS (Note T)	Total	Allocator				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				0	0	0
6A	True-Up Adjustment [See Note 1]				0		
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0	$0	$0
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0		0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)						0
10	Plus 12 CP of Network Load not in Line 8 (Note C)						0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)						0
12	Plus Contract Demand of firm P-T-P over one year						0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0
15	Divisor (Sum Lines 8-14)				0	0	0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000					
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000					
		Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000		
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000		
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	0.000 Capped at weekly and daily rates			$0.000		
21	FERC Annual Charge ($ / MWh) (Note E)	Short Term			$0.000 Short Term		
22		Long Term			$0.000 Long Term		

Note 1. Calculated in accordance with the International Transmission Company Annual Rate Calculation and True-up Procedures in Attachment O-International of this Tariff.

Attachment O-ITC

Page 2 of 56

Exhibit B-4

Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/___

Utilizing FERC Form 1 Data

International Transmission Company

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	GROSS PLANT IN SERVICE (Note AA)							
1	Production	205.46.g		NA				
2	Transmission (Note U)	207.58.g		TP	0.00000	0		0
3	Distribution	207.75.g		NA				
4	General & Intangible (Note U)	205.5.g & 207.99.g		W/S	0.00000	0		0
5	Common	356.1		CE	0.00000	0		0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP =	0.000%	0	0	0
	ACCUMULATED DEPRECIATION (Note AA)							
7	Production	219.20-24.c		NA				
8	Transmission (Note U)	219.25c		TP	0.00000	0		0
9	Distribution	219.26c		NA				
10	General & Intangible (Note U)	219.28c & 200.21.c		W/S	0.00000	0		0
11	Common	356.1		CE	0.00000	0		0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0	0	0
	NET PLANT IN SERVICE							
13	Production	(Line 1 – Line 7)	0					
14	Transmission	(Line 2 – Line 8)	0			0		0
15	Distribution	(Line 3 – Line 9)	0					
16	General & Intangible	(Line 4 – Line 10)	0			0		0
17	Common	(Line 5 – Line 11)	0			0		0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP =	0.000%	0	0	0
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative) (Note V)	273.8.k		NA	zero	0		
20	Account No. 282 (enter negative) (Note V)	275.2.k		NP	0.00000	0		0
21	Account No. 283 (enter negative) (Note V) [See Note 2.]	277.9.k		NP	0.00000	0		0
22	Account No. 190 (Note V) [See Note 2.]	234.8.c		NP	0.00000	0		0
23	Account No. 255 (enter negative) (Note V)	267.8.h		NP	0.00000	0		0
23A	Account No. 182.3 Attmt O Def	232.f				0		0
23B	Account No. 114 ADIT Deferral	200.c.12				0		0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B)		0			0	0	0
25	LAND HELD FOR FUTURE USE (Note V)	214.x.d (Note G)		TP	0.00000	0		0
	WORKING CAPITAL (Note H)							

26	CWC	calculated	0			0	0		0
27	Materials & Supplies (Note G) (Note V)	227.8.c & .16.c		TP	0.00000	0			0
28	Prepayments (Account 165) (Note V)	111.57.c		GP	0.00000	0			0
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)		0			0	0		0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)		0			0	0		0

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-ITC
Page 3 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
International Transmission Company

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	O&M							
1	Transmission [See Note 3.]	321.112.b		TE	0.00000	0		0
2	Less Account 565	321.96.b		TE	0.00000	0		0
3	A&G	323.197.b		W/S	0.00000	0		0
4	Less FERC Annual Fees			W/S	0.00000	0		0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	0		0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			TPE	0.00000	0		0
6	Common	356.1		CE	0.00000	0		0
7	Transmission Lease Payments				1.00000	0		
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0	0	0
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)							
9	Transmission	336.7.b&c		TP	0.00000	0		0
10	General & Intangible	336.10.f & 336.1.f		W/S	0.00000	0		0
11	Common	336.11.b&c		CE	0.00000	0		0
11A	Attachment O Deferral Adjustment	232.c				0		0
11B	ADIT Adjustment	114.c.9				0		0
12	TOTAL DEPRECIATION (Sum Lines 9-11B)		0			0	0	0
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i		W/S	0.00000	0		0
14	Highway and vehicle	263.i		W/S	0.00000	0		0
15	PLANT RELATED							
16	Property	263.i		GP	0.00000	0		0
17	Gross Receipts	263.i		NA	zero	0		
18	Other	263.i		GP	0.00000	0		0
19	Payments in lieu of taxes			GP	0.00000	0		0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0	0	0
	INCOME TAXES (Note K)							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%					
22	CIT= (T/1-T) * (1-(WCLTD/R)) =		0.00%					
	where WCLTD=(Page 4, Line 27) and R=(Page 4, Line 30)							
	and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from Line 21)		0.0000					
24	Amortized Investment Tax Credit (266.8f) (enter negative)							
<u>24a</u>	<u>(Excess)/Deficient Deferred Income Taxes (Note AB)</u>							
<u>24b</u>	<u>Tax Effect of Permanent Differences and AFUDC Equity (Note AC)</u>							
25	Income Tax Calculation = Line 22 * Line 28		0	NA		0	0	0
26	ITC adjustment (Line 23 * Line 24)		0	NP	0.00000	0		0
<u>26a</u>	<u>(Excess)/Deficient Deffered Income Tax Adjustment (Line 23 x Line 24a)</u>		<u>0</u>	<u>NP</u>	<u>0.00000</u>	<u>0</u>		<u>0</u>
<u>26b</u>	<u>Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)</u>		<u>0</u>	<u>NP</u>	<u>0.00000</u>	<u>0</u>	<u>0</u>	<u>0</u>
27	Total Income Taxes (Line 25 plus Line 26 <u>+ 26a + 26b</u>)		0			0	0	0
28	RETURN [Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		0	NA		0	0	0
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)		0			0	0	0

30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	0	0	0
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0	0	0

Note 3. Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
International Transmission Company

___Attachment O-ITC
Page 4 of 5
For the 12 months ended 12/31/__

SUPPORTING CALCULATIONS AND NOTES

Line No.									
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (Page 2, Line 2, Column 3)						0		
2	Less transmission plant excluded from ISO rates (Note M)								
3	Less transmission plant included in OATT Ancillary Services (Note N)								
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)						0		
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)					TP =	0.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (Page 3, Line 1, Column 3)						0		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						0		
8	Included transmission expenses (Line 6 less Line 7)						0		
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)						0.00000		
10	Percentage of transmission plant included in ISO Rates (Line 5)					TP	0.00000		
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)					TE =	0.00000		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b		0.00	0				
13	Transmission	354.21.b		0.00	0				
14	Distribution	354.23.b		0.00	0		W&S Allocator		
15	Other	354.24, 25, 26.b		0.00	0		($/Allocation)		
16	Total (Sum Lines 12-15)		0		0		= 0.00000 = WS		
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric		W&S Allocator		
17	Electric	200.3.c			(Line 17 / Line 20)		(Line 16)	CE	
18	Gas	201.3.d			0.00000		* 0.00000 =	0.00000	
19	Water	201.3.e							(7)
20	Total (Sum Lines 17-19)		0				(5)	(6)	Adjusted
	RETURN (R)						$	Adjustments	Amount
21	Long Term Interest (117, sum of 62.c through 67.c)								0
22	Preferred Dividends (118.29c) (positive number)								0
	Development of Common Stock:								
23	Proprietary Capital (112.16.c) (Note U)								0
24	Less Preferred Stock (Line 28) (Note U)						0		0
25	Less Account 216.1 (112.12.c) (enter negative) (Note U)								0
26	Common Stock (Sum Lines 23-25)						0	0	0
			$	%	Cost (Note P)		Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)			0%	0.0000		0.0000 = WCLTD		
28	Preferred Stock (112.3.c) (Note U)			0%	0.0000		0.0000		
29	Common Stock (Line 26) [See Note 4.]		0	0%	0.1388		0.0000		
30	Total (Sum Lines 27-29)		0				0.0000 =R		
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)						Load		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)								
32	b. Bundled Sales for Resale included in Divisor on Page 1								
33	Total of (a)-(b)						0		
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)								

	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.n)	
35	a. Transmission charges for all transmission transactions	$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1	$0
36a	c. Transmission charges from Schedules associated with Attachment GG (Note X)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note Z)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Note 4. Allowed ROE set to 13.88%

~~Attachment O-ITC~~

~~Page 5 of 6~~
~~Formula Rate -- Non-Levelized~~
~~Rate Formula Template~~
~~For the 12 months ended 12/31/___~~
~~Utilizing FERC Form 1 Data~~

~~International Transmission Company~~

~~SUPPORTING CALCULATIONS AND NOTES~~

~~Note 4. Allowed ROE set to 13.88%~~

Attachment O-ITC
Page 56 of

Exhibit B-4
56

Formula Rate – Non-Levelized
ended 12/31/

For the 12 months

Rate Formula Template
~~For the 12 months ended 12/31/~~
Utilizing FERC Form 1 Data

International Transmission Company

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:		
	FIT =	0.00%
	SIT =	0.00% (State Income Tax Rate or Composite SIT)
	p =	0.00% (percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking – the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.
T	The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Calculate using 13 month average balance.
V	Calculate using average of beginning and end of year balances.
W	Pursuant to Attachment GG of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.
X	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Y	Pursuant to Attachment MM of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.
Z	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
AA	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
AB	Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).
AC	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: International Transmission Company

Cost Year: ____________________
Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant			
2				
3		303	Miscellaneous Intangible Plant (Note 1)	2.00%
4				
5	Transmission Plant Accounts (Note 2)			
6				
7		350	Land Rights	0.91%
8		352	Structures and improvements	1.47%
9		353	Station Equipment	2.02%
10		354	Towers & Fixtures	1.37%
11		355	Poles & Fixtures (Note 1)	1.83%
12		356	Overhead Conductors & Devices	1.57%
13		357	Underground Conduit	1.47%
14		358	Underground Conductors & Devices	1.51%
15				

16	General Plant Accounts (Note 2)		
17			
18	390	Structures and improvements	1.51%
19	391-A	Office Furniture & Equipment	5.00%
20	391-B	Office Furn & Eq--Computers	20.00%
21	391-C	Office Furniture & Equipment--Software	20.00%
22	392	Transportation Equipment	22.11%
23	393	Stores Equipment--10 year	10.00%
24	394	Tools Shop & Garage Equipment	10.00%
25	396	Power Operated Equipment	6.92%
26	397	Communication Equipment	10.00%
27	398	Miscellaneous Equipment	10.00%
28			

29 Note 1: The amortization rate for Account 303, intangible plant, and the depreciation rate for Account 355,
30 poles and fixtures were authorized in
31 FERC Docket No. ____________
32 Note 2: Depreciation rates for other transmission and general plant accounts were authorized
33 in FERC Docket No. ER09-1530, filed July 31, 2009, Order received September 22, 2009.

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/__

Michigan Electric Transmission Company, LLC

Line No.		Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)				$0
	REVENUE CREDITS (Note T)				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				$0
6A	True-Up Adjustment (See Note 1)				0
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)				0
10	Plus 12 CP of Network Load not in Line 8 (Note C)				0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)				0
12	Plus Contract Demand of firm P-T-P over one year				0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)				0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)				0
15	Divisor (Sum Lines 8-14)				0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000			
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000			
		Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	0.000 Capped at weekly and daily rates			$0.000
21	FERC Annual Charge ($ / MWh) (Note E)	$0.000 Short Term			$0.000 Short Term
22		$0.000 Long Term			$0.000 Long Term

Note 1: Calculated in accordance with the Michigan Electric Transmission Company, LLC Annual Rate Calculation and True-up Procedures in Attachment O of this Tariff.

Attachment O-METC
Page 2 of 5

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

For the 12 months ended 12/31/__

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE (Note BB)					
1	Production	205.46.g	0	NA	zero	0
2	Transmission (Note V)	207.58.g	0	TP	0.00000	0
3	Distribution	207.75.g	0	NA	zero	0
4	General & Intangible (Note V)	205.5.g & 207.99.g	0	W/S	0.00000	0
5	Common	356.1	0	CE	0.00000	0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP =	0.000%	0
	ACCUMULATED DEPRECIATION (Note BB)					
7	Production	219.20-24.c	0	NA	zero	0
8	Transmission (Note V)	219.25c	0	TP	0.00000	0
9	Distribution	219.26c	0	NA	zero	0
10	General & Intangible (Note V)	219.28c & 200.21.c	0	W/S	0.00000	0
11	Common	356.1	0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0
	NET PLANT IN SERVICE					
13	Production	(Line 1 -- Line 7)	0			0
14	Transmission (Note V)	(Line 2 -- Line 8)	0			0
15	Distribution	(Line 3 -- Line 9)	0			0
16	General & Intangible (Note V)	(Line 4 -- Line 10)	0			0
17	Common	(Line 5 -- Line 11)	0			0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP =	0.000%	0
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative) (Note W)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative) (Note W)	275.2.k	0	NP	0.00000	0
21	Account No. 283 (enter negative) (Note W)	[See Note 2.] 277.9.k	0	NP	0.00000	0
22	Account No. 190 (Note W) [See Note 2.]	234.8.c	0	NP	0.00000	0
23	Account No. 255 (enter negative) (Note W)	267.8.h	0	NP	0.00000	0
23a	Account No. 182.3 Deferral		0	NP	0.00000	0
23b	Account No. 114 ADIT		0	NP	0.00000	0
23c	Amortization of Deferral		0	NP	0.00000	0
23d	Amortization of ADIT		0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23d)		0			0
25	LAND HELD FOR FUTURE USE (Note W)	214.x.d (Note G)	0	TP	0.00000	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	0			0
27	Materials & Supplies (Note G) (Note W)	227.8.c & .16.c	0	TPE	0.00000	0
28	Prepayments (Account 165) (Note W)	111.57.c	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)		0			0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)		0			0

Note 2: Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-METC
Page 3 of 5

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/___

Michigan Electric Transmission Company, LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	0	TE	0.00000	0
2	Less Account 565	321.96.b	0	TE	0.00000	0
2a	Customer Records	322.164.b	0	W/S	0.00000	0
3	A&G	323.197.b	0	W/S	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TP	0.00000	0
6	Common	356.1	0	CE	0.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (Sum Lines 1, 2a, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0
	DEPRECIATION & AMORTIZATION EXPENSE (Note BB)					
9	Transmission	336.7.b	0	TP	0.00000	0
10	General & Intangible	336.10.f & 336.1.f	0	W/S	0.00000	0
11	Common	336.11.b	0	CE	0.00000	0
11a	Regulatory Deferral Amortization (Note I-a)		0			0
11b	ADIT Amortization		0			0
12	TOTAL DEPRECIATION (Sum Lines 9-11b)		0			0
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.3,4,8.i	0	W/S	0.00000	0
14	Highway and vehicle	263.i	0	W/S	0.00000	0
15	PLANT RELATED					
16	Property	263.i	0	GP	0.00000	0
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT = (T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from Line 21)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
<u>24a</u>	<u>(Excess)/Deficient Deferred Income Tax (Note CC)</u>					
<u>24b</u>	<u>Tax Effect of Permanent Differences and AFUDC Equity (Note DD)</u>					
25	Income Tax Calculation = Line 22 * Line 28		0	NA	zero	0
26	ITC adjustment (Line 23 * Line 24)		0	NP	0.00000	0
<u>26a</u>	<u>(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)</u>		0	NP	0.00000	0
<u>26b</u>	<u>Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)</u>		0	NP	0.00000	0
27	Total Income Taxes (Line 25 plus Line 26 <u>plus 26a plus 26b</u>)		0			0
28	RETURN		0	NA		0
	[Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]					

29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)	0	0
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note X) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	0
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Z) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0

Attachment O-METC
Page 4 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template

Michigan Electric Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTERS

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (Page 2, Line 2, Column 3)						0	
2	Less transmission plant excluded from ISO rates (Note M)						0	
3	Less transmission plant included in OATT Ancillary Services (Note N)						0	
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)						0	
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)					TP =	0.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (Page 3, Line 1, Column 3)						0	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						0	
8	Included transmission expenses (Line 6 less Line 7)						0	
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)						0.00000	
10	Percentage of transmission plant included in ISO Rates (Line 5)					TP	0.00000	
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)					TE =	0.00000	

Line No.	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		
12	Production	354.20.b	0	0.00	0		
13	Transmission	354.21.b	0	0.00	0		
14	Distribution	354.23.b	0	0.00	0	W&S Allocator	
15	Other	354.24, 25, 26, 27.b	0	0.00	0	($/Allocation)	
16	Total (Sum Lines 12-15)		0		0	= 0.00000	= WS

Line No.	COMMON PLANT ALLOCATOR (CE) (Note O)		$	% Electric	W&S Allocator		CE
				(Line 17 / Line 20)	(Line 16)		
17	Electric	200.3.c	0	0.00000	* 0.00000	=	0.00000
18	Gas	201.3.d	0				
19	Water	201.3.e	0				
20	Total (Sum Lines 17-19)		0				

Line No.	RETURN (R)	$				
21	Long Term Interest (117, sum of 62.c through 67.c) see footnote to FERC Form 1	$0				
22	Preferred Dividends (118.29c) (positive number)	0				
	Development of Common Stock:					
23	Proprietary Capital (112.16.c) (Note V)	0				
24	Less Preferred Stock (Line 28) (Note V)	0				
25	Less Account 216.1 (112.12.c) (enter negative) (Note V)	0				
25a	Less 2003 Equity Adjustment (253.3.b) (enter negative) (Note V)	0				
26	Common Stock (Sum Lines 23-25a)	0				
		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c) (Note V)	0	0%	0.0000	0.0000	= WCLTD
28	Preferred Stock (112.3.c) (Note V)	0	0%	0.0000	0.0000	
29	Common Stock (Line 26)	0	0%	0.0000	0.0000	
30	Total (Sum Lines 27-29)	0			0.0000	=R

Line No.	REVENUE CREDITS	
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)	Load
31	a. Bundled Non-RQ Sales for Resale (311.x.h)	0
32	b. Bundled Sales for Resale included in Divisor on Page 1	0

33	Total of (a)-(b)	0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)	$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)	
35	a. Transmission charges for all transmission transactions	$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1	$0
36a	c. Transmission charges from Schedules associated with Attachment GG (Note Y)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note AA)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Attachment O-METC
Page 5 of 5
For the 12 months ended 12/31/___

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

Michigan Electric Transmission Company, LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as reported on Page 400, Column b of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 Line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

I-a For the rate period June 1, 2006 through May 31, 2007, this amount will reflect an adjustment (positive or negative) equal to the true-up amount, including interest, determined pursuant to the methodology approved in Docket No. ER06-xx, to eliminate the rate impact of the differences caused by the use of a projected year 2005 deferral balance.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:	FIT =	0.00%	
	SIT =	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation may be added to the ROE up to the upper end of the zone of reasonableness established by FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.

T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

V Calculate using 13 month average balance.

W Calculate using average of beginning and end of year balances.

X	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.
Y	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Z	Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.
AA	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
BB	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
CC	Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).
DD	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: Michigan Electric Transmission Company

Cost Year: ____________________
Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant			
2		303	Miscellaneous Intangible Plant	2.09%
3				
4	Transmission Plant Accounts			
5		350	Land Rights	1.32%
6		352	Structures & Improvements	1.66%
7		353	Station Equipment	2.15%
8		354	Towers & Fixtures	1.57%
9		355	Poles & Fixtures	1.69%
10		356	Overhead Conductors & Devices	1.72%
11		357	Underground Conduit	1.67%
12		358	Underground Conductors & Devices	1.83%
13		359	Roads and Trails	0.88%
14				
15	General Plant Accounts			
16		390	Structures & Improvements	1.50%
17		391-A	Office Furniture & Equipment--Software	20.00%
18		391-B	Office Furn & Eq--Equipment	5.00%

19	391-C	Office Furniture & Equipment--Computers	20.00%
20	392	Transportation Equipment	14.51%
21	393	Stores Equipment	10.00%
22	394	Tools, Shop & Garage Equipment	10.00%
23	395	Laboratory Equipment	10.00%
24	396	Power Operated Equipment	6.33%
25	397	Communication Equipment	10.00%
26	398	General Miscellaneous Equipment	10.00%
27			

28 Note: Depreciation/amortization rates for intangible, transmission and general plant were authorized

29 in FERC Docket No. ER10-185, filed October 30, 2009. Order received December 18, 2009.

Attachment O-ITCM
Page 1 of 5

Formula Rate – Non-Levelized ________Rate Formula Template ________________For the 12 months ended 12/31/__

Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.		(1)	(2)		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)		12 months		$0	$0	$0
	REVENUE CREDITS (Note T)	Total	Allocator				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				0	0	0
6A	True-Up Adjustment (See Note 1)				0		0
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0	$0	$0
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0		0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)						0
10	Plus 12 CP of Network Load not in Line 8 (Note C)						0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)						0
12	Plus Contract Demand of firm P-T-P over one year						0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0
15	Divisor (Sum Lines 8-14)				0	0	0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000					
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000					
		Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000		
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000		
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4160; Line 16 / 8760 * 1000)	0.000 Capped at weekly and daily rates			$0.000		
21	FERC Annual Charge ($ / MWh) (Note E)	Short Term			$0.000 Short Term		
22		Long Term			$0.000 Long Term		

Note 1. Calculated in accordance with the ITC Midwest, LLC Annual Rate Calculation and True-up Procedures in Attachment O-Midwest of this Tariff.

Attachment O-ITCM
Page 2 of 5

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/___

ITC Midwest LLC

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	GROSS PLANT IN SERVICE (Note AA)							
1	Production	205.46.g		NA				0
2	Transmission (Note U)	207.58.g	0	TP	0.00000	0		0
3	Distribution	207.75.g		NA				
4	General & Intangible (Note U)	205.5.g & 207.99.g	0	W/S	0.00000	0		0
5	Common	356.1		CE	0.00000	0		0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP=	0.000%	0	0	0
	ACCUMULATED DEPRECIATION (Note AA)							
7	Production	219.20-24.c		NA				
8	Transmission (Note U)	219.25c	0	TP	0.00000	0		0
9	Distribution	219.26c		NA				
10	General & Intangible (Note U)	219.28c & 200.21.c	0	W/S	0.00000	0		0
11	Common	356.1		CE	0.00000	0		0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0	0	0
	NET PLANT IN SERVICE							
13	Production	(Line 1-Line 7)	0					
14	Transmission	(Line 2-Line 8)	0			0		0
15	Distribution	(Line 3-Line 9)						
16	General & Intangible	(Line 4-Line 10)	0			0		0
17	Common	(Line 5-Line 11)	0			0		0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP=	0.000%	0	0	0
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative) (Note V)	273.8.k		NA	zero	0		
20	Account No. 282 (enter negative) (Note V)	275.2.k		NP	0.00000	0		0
21	Account No. 283 (enter negative) (Note V)	277.9.k		NP	0.00000	0		0
22	Account No. 190 (Note V) [See Note 2.]	234.8.c		NP	0.00000	0		0
23	Account No. 255 (enter negative) (Note V)	267.8.h		NP	0.00000	0		0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B)		0			0	0	0
25	LAND HELD FOR FUTURE USE (Note V)	214.x.d (Note G)		TP	0.00000	0		0
	WORKING CAPITAL (Note H)							
26	CWC	calculated	0			0	0	0
27	Materials & Supplies (Note G) (Note V)	227.8.c & .16.c	0	TPE	0.00000	0		0
28	Prepayments (Account 165) (Note V)	111.57.c		GP	0.00000	0		0
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)		0			0	0	0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)		0			0	0	0

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-ITCM
Page 3 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.	(1) O&M	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
1	Transmission [See Note 3.]	321.112.b		TE	0.00000	0		0
2	Less Account 565	321.96.b		TE	0.00000	0		0
3	A&G	323.197.b		W/S	0.00000	0		0
4	Less FERC Annual Fees			W/S	0.00000	0		0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	0		0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			TPS	0.00000	0		0
6	Common	356.1		CE	0.00000	0		0
7	Transmission Lease Payments				1.00000	0		
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0	0	0
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)							
9	Transmission	336.7.b&c		TP	0.00000	0		0
10	General & Intangible	336.10.f & 336.1.f		W/S	0.00000	0		0
11	Common	336.11.b&c		CE	0.00000	0		0
12	TOTAL DEPRECIATION (Sum Lines 9-11B)		0			0	0	0
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i	0	W/S	0.00000	0		0
14	Highway and vehicle	263.i		W/S	0.00000	0		0
15	PLANT RELATED							
16	Property	263.i	0	GP	0.00000	0		0
17	Gross Receipts	263.i		NA	zero	0		
18	Other	263.i		GP	0.00000	0		0
19	Payments in lieu of taxes			GP	0.00000	0		0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0	0	0
	INCOME TAXES (Note K)							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%					
22	CIT= (T/1-T) * (1-(WCLTD/R)) =		0.00%					
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30) and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from Line 21)		0.0000					
24	Amortized Investment Tax Credit (266.8f) (enter negative)							
24a	(Excess)/Deficient Deferred Income Taxes (Note AB)							
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note AC)							
25	Income Tax Calculation = Line 22 * Line 28		0	NA		0	0	0
26	ITC adjustment (Line 23 * Line 24)			NP	0.00000	0		0
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)		0	NP	0.00000	0		0
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)		0	NP	0.00000	0		0
27	Total Income Taxes (Line 25 + Line 26 + 26a + 26b) 0		0		NP		0	0
28	RETURN [Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		0	NA		0	0	0
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)		0			0	0	0
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W)							

	[Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	0	0	0
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0	0	0

Note 3: Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

_______________For the 12 months ended 12/31___

ITC Midwest LLC
SUPPORTING CALCULATIONS AND NOTES

Line No.		Form 1 Reference	$	TP					
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (Page 2, Line 2, Column 3)					0			
2	Less transmission plant excluded from ISO rates (Note M)								
3	Less transmission plant included in OATT Ancillary Services (Note N)								
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)					0.			
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)				TP =	0.00000			
	TRANSMISSION EXPENSES								
6	Total transmission expenses (Page 3, Line 1, Column 3)					0			
7	Less transmission expenses included in OATT Ancillary Services (Note L)					0.			
8	Included transmission expenses (Line 6 less Line 7)					0.			
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)					0.00000			
10	Percentage of transmission plant included in ISO Rates (Line 5)				TP	0.00000			
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)				TE =	0.00000			
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b		0.00	0				
13	Transmission	354.21.b	0	0.00	0				
14	Distribution	354.23.b		0.00	0.	W&S Allocator			
15	Other	354.24, 25, 26.b		0.00	0	($/Allocation)			
16	Total (Sum Lines 12-15)		0		0	= 0.00000	= WS		
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric	W&S Allocator			
17	Electric	200.3.c	0		(Line 17 / Line 20)	(Line 16)		CE	
18	Gas	201.3.d			0.00000	* 0.00000	=	0.00000	
19	Water	201.3.e	0						(7)
20	Total (Sum Lines 17-19)		0			(5)		(6)	Adjusted
	RETURN (R)					$		Adjustments	Amount
21	Long Term Interest (117, sum of 62.c through 67.c)					0			0
22	Preferred Dividends (118.29c) (positive number)								0
	Development of Common Stock:								
23	Proprietary Capital (112.16.c) (Note U)					0			0
24	Less Preferred Stock (Line 28) (Note U)					0			0
25	Less Account 216.1 (112.12.c) (enter negative) (Note U)								0
26	Common Stock (Sum Lines 23-25)					0		0	0
			$	%	Cost (Note P)	Weighted			
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)		0	0%	0.0000	0.0000	= WCLTD		
28	Preferred Stock (112.3.c) (Note U)			0%	0.0000	0.0000			
29	Common Stock (Line 26) [See Note 4.]		0	0%	0.0000	0.0000			
30	Total (Sum Lines 27-29)		0			0.0000	= R		
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)					Load			
31	a. Bundled Non-RQ Sales for Resale (311.x.h)								
32	b. Bundled Sales for Resale included in Divisor on Page 1								
33	Total of (a)-(b)					0			
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)					0			
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.n)								
35	a. Transmission charges for all transmission transactions					$0			
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1					$0			

36a	c. Transmission charges from Schedules associated with Attachment GG (Note X)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note Z)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Note 4. Allowed ROE set to 12.38%

Attachment O-ITCM
Page 5 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

ITC Midwest LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:		
	FIT =	0.00%
	SIT =	0.00% (State Income Tax Rate or Composite SIT)
	p =	0.00% (percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation and 50 basis point adder for independence may be added to the allowed ROE up to the upper end of the zone of reasonableness established by FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.

T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Calculate using 13 month average balance.

V Calculate using average of beginning and end of year balances.

W Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Y Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

Z Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

AA Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

AB Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).

AC Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: ITC Midwest LLC

Cost Year: ____________________

Projected/Actual: ____________________

Attachment O-ITCM
Page 6 of 6

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant		Intangible Plant	
2				
3		303	Miscellaneous Intangible Plant (Note 1)	2.00%
4	Transmission Plant Accounts (Note 2)			
5		350	Land Rights	1.33%
6		352	Structures & Improvements	1.55%
7		353	Station Equipment	2.05%
8		354	Towers & Fixtures	1.22%
9		355	Poles & Fixtures	1.69%
10		356	Overhead Conductors & Devices	1.81%
11		357	Underground Conduit	1.57%
12		358	Underground Conductors & Devices	1.66%
13		359	Roads and Trails	1.33%
14	General Plant Accounts (Note 2)			
15		389	Land Rights	1.33%
16		390	Structures & Improvements	1.50%
17		391-A	Office Furniture & Equipment--	5.00%

		Equipment	
18	391-B	Office Furn & Eq--Computers	20.00%
19	391-C	Office Furniture & Equipment--Software	20.00%
20	392	Transportation Equipment	20.13%
21	393	Stores Equipment	10.00%
22	394	Tools, Shop & Garage Equipment	10.00%
23	395	Laboratory Equipment	10.00%
24	396	Power Operated Equipment	6.36%
25	397	Communication Equipment	10.00%
26	398	General Miscellaneous Equipment	10.00%
27			
28	Note 1: The amortization rate for Account 303, intangible plant, was authorized in		
29	FERC Docket No. ________		
30	Note 2: Depreciation rates for transmission and general plant were authorized		
31	in FERC Docket No. ER10-2110, filed August 2, 2010. Order received September 2, 2010.		

CLEAN TARIFF

Attachment O-ITC
Page 1 of 5
For the 12 months ended 12/31/__

Formula Rate -- Non-Levelized

Exhibit B-4
Rate Formula Template
Utilizing FERC Form 1 Data

International Transmission Company

Line No.		(1)	(2)		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)		12 months		$0	$0	$0
	REVENUE CREDITS (Note T)	Total	Allocator				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				0	0	0
6A	True-Up Adjustment [See Note 1.]				0		
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0	$0	$0
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0		0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)						0
10	Plus 12 CP of Network Load not in Line 8 (Note C)						0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)						0
12	Plus Contract Demand of firm P-T-P over one year						0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0
15	Divisor (Sum Lines 8-14)				0	0	0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000					
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000					
		Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000		
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000		
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	0.000 Capped at weekly and daily rates			$0.000		
21	FERC Annual Charge ($ / MWh) (Note E)	Short Term			$0.000 Short Term		
22		Long Term			$0.000 Long Term		

Note 1. Calculated in accordance with the International Transmission Company Annual Rate Calculation and True-up Procedures in Attachment O-International of this Tariff.

Attachment O-ITC
Page 2 of 5

Exhibit B-4

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/__

International Transmission Company

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	GROSS PLANT IN SERVICE (Note AA)							
1	Production	205.46.g		NA				
2	Transmission (Note U)	207.58.g		TP	0.00000	0		0
3	Distribution	207.75.g		NA				
4	General & Intangible (Note U)	205.5.g & 207.99.g		W/S	0.00000	0		0
5	Common	356.1		CE	0.00000	0		0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP =	0.000%	0	0	0
	ACCUMULATED DEPRECIATION (Note AA)							
7	Production	219.20-24.c		NA				
8	Transmission (Note U)	219.25c		TP	0.00000	0		0
9	Distribution	219.26c		NA				
10	General & Intangible (Note U)	219.28c & 200.21.c		W/S	0.00000	0		0
11	Common	356.1		CE	0.00000	0		0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0	0	0
	NET PLANT IN SERVICE							
13	Production	(Line 1 – Line 7)	0					
14	Transmission	(Line 2 – Line 8)	0			0		0
15	Distribution	(Line 3 – Line 9)	0					
16	General & Intangible	(Line 4 – Line 10)	0			0		0
17	Common	(Line 5 – Line 11)	0			0		0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP =	0.000%	0	0	0
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative) (Note V)	273.8.k		NA	zero	0		
20	Account No. 282 (enter negative) (Note V)	275.2.k		NP	0.00000	0		0
21	Account No. 283 (enter negative) (Note V) [See Note 2.]	277.9.k		NP	0.00000	0		0
22	Account No. 190 (Note V) [See Note 2.]	234.8.c		NP	0.00000	0		0
23	Account No. 255 (enter negative) (Note V)	267.8.h		NP	0.00000	0		0
23A	Account No. 182.3 Attmt O Def	232.f				0		0
23B	Account No. 114 ADIT Deferral	200.c.12				0		0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B)		0			0	0	0
25	LAND HELD FOR FUTURE USE (Note V)	214.x.d (Note G)		TP	0.00000	0		0
	WORKING CAPITAL (Note H)							
26	CWC	calculated	0			0	0	0
27	Materials & Supplies (Note G) (Note V)	227.8.c & .16.c		TP	0.00000	0		0
28	Prepayments (Account 165) (Note V)	111.57.c		GP	0.00000	0		0

29	TOTAL WORKING CAPITAL (Sum Lines 26-28)	0	0	0	0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)	0	0	0	0

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-ITC
Page 3 of 5
For the 12 months ended 12/31/__

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
International Transmission Company

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	O&M							
1	Transmission [See Note 3.]	321.112.b		TE	0.00000	0		0
2	Less Account 565	321.96.b		TE	0.00000	0		0
3	A&G	323.197.b		W/S	0.00000	0		0
4	Less FERC Annual Fees			W/S	0.00000	0		0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	0		0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			TP	0.00000	0		0
6	Common	356.1		CE	0.00000	0		0
7	Transmission Lease Payments				1.00000	0		
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0	0	0
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)							
9	Transmission	336.7.b&c		TP	0.00000	0		0
10	General & Intangible	336.10.f & 336.1.f		W/S	0.00000	0		0
11	Common	336.11.b&c		CE	0.00000	0		0
11A	Attachment O Deferral Adjustment	232.e				0		0
11B	ADIT Adjustment	114.c.9				0		0
12	TOTAL DEPRECIATION (Sum Lines 9-11B)		0			0	0	0
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i		W/S	0.00000	0		0
14	Highway and vehicle	263.i		W/S	0.00000	0		0
15	PLANT RELATED							
16	Property	263.i		GP	0.00000	0		0
17	Gross Receipts	263.i		NA	zero	0		
18	Other	263.i		GP	0.00000	0		0
19	Payments in lieu of taxes			GP	0.00000	0		0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0	0	0
	INCOME TAXES (Note K)							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%					
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%					
	where WCLTD=(Page 4, Line 27) and R= (Page 4, Line 30)							
	and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from Line 21)		0.0000					
24	Amortized Investment Tax Credit (266.8f) (enter negative)							
24a	(Excess)/Deficient Deferred Income Taxes (Note AB)							
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note AC)							
25	Income Tax Calculation = Line 22 * Line 28		0	NA		0	0	0
26	ITC adjustment (Line 23 * Line 24)		0	NP	0.00000	0	0	
26a	(Excess)/Deficient Deffered Income Tax Adjustment (Line 23 x Line 24a)		0	NP	0.00000	0		0
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)		0	NP	0.00000	0	0	0
27	Total Income Taxes (Line 25 plus Line 26 + 26a + 26b)		0			0	0	0
28	RETURN [Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		0	NA		0	0	0
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)		0			0	0	0

30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	0	0	0
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0	0	0

Note S. Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Attachment O-ITC
Page 4 of 5
For the 12 months ended 12/31/__

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
International Transmission Company

SUPPORTING CALCULATIONS AND NOTES

Line No.									
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (Page 2, Line 2, Column 3)						0		
2	Less transmission plant excluded from ISO rates (Note M)								
3	Less transmission plant included in OATT Ancillary Services (Note N)								
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)						0		
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)					TP =	0.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (Page 3, Line 1, Column 3)						0		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						0		
8	Included transmission expenses (Line 6 less Line 7)						0		
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)						0.00000		
10	Percentage of transmission plant included in ISO Rates (Line 5)					TP	0.00000		
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)					TE =	0.00000		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b		0.00	0				
13	Transmission	354.21.b		0.00	0				
14	Distribution	354.23.b		0.00	0		W&S Allocator		
15	Other	354.24, 25, 26.b		0.00	0		($/Allocation)		
16	Total (Sum Lines 12-15)		0		0		= 0.00000	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric		W&S Allocator		
17	Electric	200.3.c			(Line 17 / Line 20)		(Line 16)	CE	
18	Gas	201.3.d			0.00000		* 0.00000	= 0.00000	
19	Water	201.3.e							(7)
20	Total (Sum Lines 17-19)		0				(5)	(6)	Adjusted
	RETURN (R)						$	Adjustments	Amount
21	Long Term Interest (117, sum of 62.c through 67.c)								0
22	Preferred Dividends (118.29c) (positive number)								0
	Development of Common Stock:								
23	Proprietary Capital (112.16.c) (Note U)								0
24	Less Preferred Stock (Line 28) (Note U)						0		0
25	Less Account 216.1 (112.12.c) (enter negative) (Note U)								0
26	Common Stock (Sum Lines 23-25)						0	0	0
			$	%	Cost (Note P)		Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)			0%	0.0000		0.0000	= WCLTD	
28	Preferred Stock (112.3.c) (Note U)			0%	0.0000		0.0000		
29	Common Stock (Line 26) [See Note 4.]		0	0%	0.1388		0.0000		
30	Total (Sum Lines 27-29)		0				0.0000	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)						Load		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)								
32	b. Bundled Sales for Resale included in Divisor on Page 1								
33	Total of (a)-(b)						0		
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)								

	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.a)	
35	a. Transmission charges for all transmission transactions	$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1	$0
36a	c. Transmission charges from Schedules associated with Attachment GG (Note X)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note Z)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Note 4. Allowed ROE set to 13.88%

Attachment O-ITC
Page 5 of 5
For the 12 months ended 12/31/__

Exhibit B-4
Formula Rate – Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data

International Transmission Company

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter	
A	Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
B	Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
C	Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
D	Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Exclude ADIT balances when the associated income tax consequences have been paid by others. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26). Inputs Required: FIT = 0.00% SIT = 0.00% (State Income Tax Rate or Composite SIT) p = 0.00% (percent of federal income tax deductible for state purposes)
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts.
P	Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.
T	The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Calculate using 13 month average balance.
V	Calculate using average of beginning and end of year balances.
W	Pursuant to Attachment GG of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

X	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Y	Pursuant to Attachment MM of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.
Z	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
AA	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
AB	Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).
AC	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: International Transmission Company

Cost Year: ________________________
Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant			
2				
3		303	Miscellaneous Intangible Plant (Note 1)	2.00%
4				
5	Transmission Plant Accounts (Note 2)			
6				
7		350	Land Rights	0.91%
8		352	Structures and improvements	1.47%
9		353	Station Equipment	2.02%
10		354	Towers & Fixtures	1.37%
11		355	Poles & Fixtures (Note 1)	1.83%
12		356	Overhead Conductors & Devices	1.57%
13		357	Underground Conduit	1.47%
14		358	Underground Conductors & Devices	1.51%
15				

16	General Plant Accounts (Note 2)		
17			
18	390	Structures and improvements	1.51%
19	391-A	Office Furniture & Equipment	5.00%
20	391-B	Office Furn & Eq--Computers	20.00%
21	391-C	Office Furniture & Equipment--Software	20.00%
22	392	Transportation Equipment	22.11%
23	393	Stores Equipment--10 year	10.00%
24	394	Tools Shop & Garage Equipment	10.00%
25	396	Power Operated Equipment	6.92%
26	397	Communication Equipment	10.00%
27	398	Miscellaneous Equipment	10.00%
28			
29	Note 1: The amortization rate for Account 303, intangible plant, and the depreciation rate for Account 355,		
30	poles and fixtures were authorized in		
31	FERC Docket No. ____________		
32	Note 2: Depreciation rates for other transmission and general plant accounts were authorized		
33	in FERC Docket No. ER09-1530, filed July 31, 2009, Order received September 22, 2009.		

Attachment O-METC
Page 1 of 5

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/__

Michigan Electric Transmission Company, LLC

Line No.		Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)				$0
	REVENUE CREDITS (Note T)				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				$0
6A	True-Up Adjustment (See Note 1)				0
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)				0
10	Plus 12 CP of Network Load not in Line 8 (Note C)				0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)				0
12	Plus Contract Demand of firm P-T-P over one year				0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)				0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)				0
15	Divisor (Sum Lines 8-14)				0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000			
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000			
		Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	0.000 Capped at weekly and daily rates			$0.000
21	FERC Annual Charge ($ / MWh) (Note E)	$0.000 Short Term			$0.000 Short Term
22		$0.000 Long Term			$0.000 Long Term

Note 1: Calculated in accordance with the Michigan Electric Transmission Company, LLC Annual Rate Calculation and True-up Procedures in Attachment O of this Tariff.

Attachment O-METC
Page 2 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE (Note BB)					
1	Production	205.46.g	0	NA	zero	0
2	Transmission (Note V)	207.58.g	0	TP	0.00000	0
3	Distribution	207.75.g	0	NA	zero	0
4	General & Intangible (Note V)	205.5.g & 207.99.g	0	W/S	0.00000	0
5	Common	356.1	0	CE	0.00000	0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP =	0.000%	0
	ACCUMULATED DEPRECIATION (Note BB)					
7	Production	219.20-24.c	0	NA	zero	0
8	Transmission (Note V)	219.25c	0	TP	0.00000	0
9	Distribution	219.26c	0	NA	zero	0
10	General & Intangible (Note V)	219.28c & 200.21.c	0	W/S	0.00000	0
11	Common	356.1	0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0
	NET PLANT IN SERVICE					
13	Production	(Line 1 – Line 7)	0			0
14	Transmission (Note V)	(Line 2 – Line 8)	0			0
15	Distribution	(Line 3 – Line 9)	0			0
16	General & Intangible (Note V)	(Line 4 – Line 10)	0			0
17	Common	(Line 5 – Line 11)	0			0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP =	0.000%	0
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative) (Note W)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative) (Note W)	275.2.k	0	NP	0.00000	0
21	Account No. 283 (enter negative) (Note W)	[See Note 2] 277.9.k	0	NP	0.00000	0
22	Account No. 190 (Note W) [See Note 2]	234.8.c	0	NP	0.00000	0
23	Account No. 255 (enter negative) (Note W)	267.8.h	0	NP	0.00000	0
23a	Account No. 182.3 Deferral		0	NP	0.00000	0
23b	Account No. 114 ADIT		0	NP	0.00000	0
23c	Amortization of Deferral		0	NP	0.00000	0
23d	Amortization of ADIT		0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23d)		0			0
25	LAND HELD FOR FUTURE USE (Note W)	214.x.d (Note G)	0	TP	0.00000	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	0			0
27	Materials & Supplies (Note G) (Note W)	227.8.c & .16.c	0	TP	0.00000	0
28	Prepayments (Account 165) (Note W)	111.57.c	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)		0			0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)		0			0

Note 2: Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-METC
Page 3 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)
	O&M					
1	Transmission	321.112.b	0	TE	0.00000	0
2	Less Account 565	321.96.b	0	TE	0.00000	0
2a	Customer Records	322.164.b	0	W/S	0.00000	0
3	A&G	323.197.b	0	W/S	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TP	0.00000	0
6	Common	356.1	0	CE	0.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (Sum Lines 1, 2a, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0
	DEPRECIATION & AMORTIZATION EXPENSE (Note BB)					
9	Transmission	336.7.b	0	TP	0.00000	0
10	General & Intangible	336.10.f & 336.1.f	0	W/S	0.00000	0
11	Common	336.11.b	0	CE	0.00000	0
11a	Regulatory Deferral Amortization (Note I-a)		0			0
11b	ADIT Amortization		0			0
12	TOTAL DEPRECIATION (Sum Lines 9-11b)		0			0
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.3,4,8.i	0	W/S	0.00000	0
14	Highway and vehicle	263.i	0	W/S	0.00000	0
15	PLANT RELATED					
16	Property	263.i	0	GP	0.00000	0
17	Gross Receipts	263.i	0	NA	zero	0
18	Other	263.i	0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT = (T/1-T) * (1-(WCLTD/R)) = where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30) and FIT, SIT & p are as given in footnote K.		0.00%			
23	1 / (1 - T) = (from Line 21)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
24a	(Excess)/Deficient Deferred Income Tax (Note CC)					
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note DD)					
25	Income Tax Calculation = Line 22 * Line 28		0	NA	zero	0
26	ITC adjustment (Line 23 * Line 24)		0	NP	0.00000	0
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)		0	NP	0.00000	0
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)		0	NP	0.00000	0
27	Total Income Taxes (Line 25 plus Line 26 plus 26a plus 26b)		0			0
28	RETURN [Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		0	NA		0

29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)	0	0
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note X) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	0
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Z) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0

Attachment O-METC
Page 4 of 5
For the 12 months ended 12/31/__

Formula Rate -- Non-Levelized

Rate Formula Template

Michigan Electric Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTERS

Line No.									
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (Page 2, Line 2, Column 3)						0		
2	Less transmission plant excluded from ISO rates (Note M)						0		
3	Less transmission plant included in OATT Ancillary Services (Note N)						0		
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)						0		
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)					TP=	0.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (Page 3, Line 1, Column 3)						0		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						0		
8	Included transmission expenses (Line 6 less Line 7)						0		
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)						0.00000		
10	Percentage of transmission plant included in ISO Rates (Line 5)					TP	0.00000		
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)					TE=	0.00000		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	0	0.00	0				
13	Transmission	354.21.b	0	0.00	0				
14	Distribution	354.23.b	0	0.00	0		W&S Allocator		
15	Other	354.24, 25, 26, 27.b	0	0.00	0		($/Allocation)		
16	Total (Sum Lines 12-15)		0		0		= 0.00000	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric		W&S Allocator		
17	Electric	200.3.c	0		(Line 17 / Line 20)		(Line 16)		CE
18	Gas	201.3.d	0		0.00000		* 0.00000	=	0.00000
19	Water	201.3.e	0						
20	Total (Sum Lines 17-19)		0						
	RETURN (R)		$						
21	Long Term Interest (117, sum of 62.c through 67.c) see footnote to FERC Form 1		$0						
22	Preferred Dividends (118.29c) (positive number)		0						
	Development of Common Stock:								
23	Proprietary Capital (112.16.c) (Note V)		0						
24	Less Preferred Stock (Line 28) (Note V)		0						
25	Less Account 216.1 (112.12.c) (enter negative) (Note V)		0						
25a	Less 2003 Equity Adjustment (253.3.b) (enter negative) (Note V)		0						
26	Common Stock (Sum Lines 23-25a)		0						
			$	%	Cost (Note P)		Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c) (Note V)		0	0%	0.0000		0.0000	= WCLTD	
28	Preferred Stock (112.3.c) (Note V)		0	0%	0.0000		0.0000		
29	Common Stock (Line 26)		0	0%	0.0000		0.0000		
30	Total (Sum Lines 27-29)		0				0.0000	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)						Load		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)						0		
32	b. Bundled Sales for Resale included in Divisor on Page 1						0		

33	Total of (a)-(b)	0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)	$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)	
35	a. Transmission charges for all transmission transactions	$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1	$0
36a	c. Transmission charges from Schedules associated with Attachment GG (Note Y)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note AA)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

Michigan Electric Transmission Company, LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter	
A	Peak as reported on Page 400, Column b of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
B	Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
C	Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
D	Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Exclude ADIT balances when the associated income tax consequences have been paid by others. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. The calculation of ADIT in the annual true-up calculation will use the beginning-of-year and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 Line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
I-a	For the rate period June 1, 2006 through May 31, 2007, this amount will reflect an adjustment (positive or negative) equal to the true-up amount, including interest, determined pursuant to the methodology approved in Docket No. ER06-xx, to eliminate the rate impact of the differences caused by the use of a projected year 2005 deferral balance.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26). Inputs Required: FIT = 0.00% SIT = 0.00% (State Income Tax Rate or Composite SIT) p = 0.00% (percent of federal income tax deductible for state purposes)
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts.
P	Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation may be added to the ROE up to the upper end of the zone of reasonableness established by FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.
T	The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.
V	Calculate using 13 month average balance.
W	Calculate using average of beginning and end of year balances.

X. Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

Y Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Z Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

AA Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

BB Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

CC Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).

DD Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: Michigan Electric Transmission Company

Cost Year: ______________________
Projected/Actual: ______________________

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant			
2		303	Miscellaneous Intangible Plant	2.09%
3				
4	Transmission Plant Accounts			
5		350	Land Rights	1.32%
6		352	Structures & Improvements	1.66%
7		353	Station Equipment	2.15%
8		354	Towers & Fixtures	1.57%
9		355	Poles & Fixtures	1.69%
10		356	Overhead Conductors & Devices	1.72%
11		357	Underground Conduit	1.67%
12		358	Underground Conductors & Devices	1.83%
13		359	Roads and Trails	0.88%
14				
15	General Plant Accounts			
16		390	Structures & Improvements	1.50%
17		391-A	Office Furniture & Equipment--Software	20.00%
18		391-B	Office Furn & Eq--Equipment	5.00%

19	391-C	Office Furniture & Equipment--Computers	20.00%
20	392	Transportation Equipment	14.51%
21	393	Stores Equipment	10.00%
22	394	Tools, Shop & Garage Equipment	10.00%
23	395	Laboratory Equipment	10.00%
24	396	Power Operated Equipment	6.33%
25	397	Communication Equipment	10.00%
26	398	General Miscellaneous Equipment	10.00%
27			

28 Note: Depreciation/amortization rates for intangible, transmission and general plant were authorized
29 in FERC Docket No. ER10-185, filed October 30, 2009, Order received December 18, 2009.

Attachment O-ITCM
Page 1 of 5

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/__

ITC Midwest LLC

Line No.		(1)	(2)		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)		12 months		$0	$0	$0
	REVENUE CREDITS (Note T)	Total	Allocator				
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				0	0	0
6A	True-Up Adjustment [See Note 1.]				0		0
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0	$0	$0
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0		0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)						0
10	Plus 12 CP of Network Load not in Line 8 (Note C)						0
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)						0
12	Plus Contract Demand of firm P-T-P over one year						0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0
15	Divisor (Sum Lines 8-14)				0	0	0
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)	0.000					
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)	0.000					
		Peak Rate			Off-Peak Rate		
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	0.000			$0.000		
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	0.000 Capped at weekly rate			$0.000		
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4160; Line 16 / 8760 * 1000)	0.000 Capped at weekly and daily rates			$0.000		
21	FERC Annual Charge ($ / MWh) (Note E)	Short Term			$0.000 Short Term		
22		Long Term			$0.000 Long Term		

Note 1. Calculated in accordance with the ITC Midwest, LLC Annual Rate Calculation and True-up Procedures in Attachment O-Midwest of this Tariff.

Attachment O-ITCM
Page 2 of 5
For the 12 months ended 12/31/__

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	GROSS PLANT IN SERVICE (Note AA)							
1	Production	205.46.g		NA				0
2	Transmission (Note U)	207.58.g	0	TP	0.00000	0		0
3	Distribution	207.75.g		NA				
4	General & Intangible (Note U)	205.5.g & 207.99.g	0	W/S	0.00000	0		0
5	Common	356.1		CE	0.00000	0		0
6	TOTAL GROSS PLANT (Sum Lines 1-5)		0	GP =	0.000%	0	0	0
	ACCUMULATED DEPRECIATION (Note AA)							
7	Production	219.20-24.c		NA				
8	Transmission (Note U)	219.25c	0	TP	0.00000	0		0
9	Distribution	219.26c		NA				
10	General & Intangible (Note U)	219.28c & 200.21.c	0	W/S	0.00000	0		0
11	Common	356.1		CE	0.00000	0		0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)		0			0	0	0
	NET PLANT IN SERVICE							
13	Production	(Line 1-Line 7)	0					
14	Transmission	(Line 2-Line 8)	0			0		0
15	Distribution	(Line 3-Line 9)						
16	General & Intangible	(Line 4-Line 10)	0			0		0
17	Common	(Line 5-Line 11)	0			0		0
18	TOTAL NET PLANT (Sum Lines 13-17)		0	NP =	0.000%	0	0	0
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative) (Note V)	273.8.k		NA	zero	0		
20	Account No. 282 (enter negative) (Note V)	275.2.k		NP	0.00000	0		0
21	Account No. 283 (enter negative) (Note V)	277.9.k		NP	0.00000	0		0
22	Account No. 190 (Note V) [See Note 2.]	234.8.c		NP	0.00000	0		0
23	Account No. 255 (enter negative) (Note V)	267.8.h		NP	0.00000	0		0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B)		0			0	0	0
25	LAND HELD FOR FUTURE USE (Note V)	214.x.d (Note G)		TP	0.00000	0		0
	WORKING CAPITAL (Note H)							
26	CWC	calculated	0			0	0	0
27	Materials & Supplies (Note G) (Note V)	227.8.c & .16.c	0	TE	0.00000	0		0
28	Prepayments (Account 165) (Note V)	111.57.c		GP	0.00000	0		0
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)		0			0	0	0
30	RATE BASE (Sum Lines 18, 24, 25, & 29)		0			0	0	0

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-ITCM
Page 3 of 5
For the 12 months ended 12/31/__

Formula Rate -- Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Adjusted Amount
	O&M							
1	Transmission [See Note 3.]	321.112.b		TE	0.00000	0		0
2	Less Account 565	321.96.b		TE	0.00000	0		0
3	A&G	323.197.b		W/S	0.00000	0		0
4	Less FERC Annual Fees			W/S	0.00000	0		0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	0		0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			TP	0.00000	0		0
6	Common	356.1		CE	0.00000	0		0
7	Transmission Lease Payments				1.00000	0		
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)		0			0	0	0
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)							
9	Transmission	336.7.b&c		TP	0.00000	0		0
10	General & Intangible	336.10.f & 336.1.f		W/S	0.00000	0		0
11	Common	336.11.b&c		CE	0.00000	0		0
12	TOTAL DEPRECIATION (Sum Lines 9-11B)		0			0	0	0
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	263.i	0	W/S	0.00000	0		0
14	Highway and vehicle	263.i		W/S	0.00000	0		0
15	PLANT RELATED							
16	Property	263.i	0	GP	0.00000	0		0
17	Gross Receipts	263.i		NA	zero	0		
18	Other	263.i		GP	0.00000	0		0
19	Payments in lieu of taxes			GP	0.00000	0		0
20	TOTAL OTHER TAXES (Sum Lines 13-19)		0			0	0	0
	INCOME TAXES (Note K)							
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%					
22	CIT= (T/1-T) * (1-(WCLTD/R)) =		0.00%					
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30)							
	and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from Line 21)		0.0000					
24	Amortized Investment Tax Credit (266.8f) (enter negative)							
24a	(Excess)/Deficient Deferred Income Taxes (Note AB)							
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note AC)							
25	Income Tax Calculation = Line 22 * Line 28		0	NA		0	0	0
26	ITC adjustment (Line 23 * Line 24)			NP	0.00000	0		0
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)		0	NP	0.00000	0		0
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)		0	NP	0.00000	0		0
27	Total Income Taxes (Line 25 + Line 26 + 26a + 26b)		0	NP		0	0	0
28	RETURN [Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		0	NA		0	0	0
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)		0			0	0	0
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]		0			0	0	0

30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	0	0	0
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)	0	0	0	0

Note 3. Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Attachment O-ITCM
Page 4 of 5

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31__

ITC Midwest LLC
SUPPORTING CALCULATIONS AND NOTES

Line No.		Form 1 Reference	$	TP	Allocation			
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (Page 2, Line 2, Column 3)					0		
2	Less transmission plant excluded from ISO rates (Note M)							
3	Less transmission plant included in OATT Ancillary Services (Note N)							
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)					0		
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)				TP =	0.00000		
	TRANSMISSION EXPENSES							
6	Total transmission expenses (Page 3, Line 1, Column 3)					0		
7	Less transmission expenses included in OATT Ancillary Services (Note L)					0		
8	Included transmission expenses (Line 6 less Line 7)					0		
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)					0.00000		
10	Percentage of transmission plant included in ISO Rates (Line 5)				TP	0.00000		
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)				TE =	0.00000		
	WAGES & SALARY ALLOCATOR (W&S)							
12	Production	354.20.b		0.00	0			
13	Transmission	354.21.b	0	0.00	0			
14	Distribution	354.23.b		0.00	0	W&S Allocator		
15	Other	354.24, 25, 26.b		0.00	0	($/Allocation)		
16	Total (Sum Lines 12-15)		0		0	= 0.00000	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric (Line 17 / Line 20)	W&S Allocator (Line 16)	CE	
17	Electric	200.3.c	0		0.00000	* 0.00000	= 0.00000	
18	Gas	201.3.d						
19	Water	201.3.c	0					
20	Total (Sum Lines 17-19)		0			(5) $	(6) Adjustments	(7) Adjusted Amount
	RETURN (R)							
21	Long Term Interest (117, sum of 62.c through 67.c)					0		0
22	Preferred Dividends (118.29c) (positive number)							0
	Development of Common Stock:							
23	Proprietary Capital (112.16.c) (Note U)					0		0
24	Less Preferred Stock (Line 28) (Note U)					0		0
25	Less Account 216.1 (112.12.c) (enter negative) (Note U)							0
26	Common Stock (Sum Lines 23-25)					0	0	0
			$	%	Cost (Note P)	Weighted		
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)		0	0%	0.0000	0.0000	= WCLTD	
28	Preferred Stock (112.3.c) (Note U)			0%	0.0000	0.0000		
29	Common Stock (Line 26) [See Note 4.]		0	0%	0.0000	0.0000		
30	Total (Sum Lines 27-29)		0			0.0000	=R	
	REVENUE CREDITS							
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)					Load		
31	a. Bundled Non-RQ Sales for Resale (311.x.h)							
32	b. Bundled Sales for Resale included in Divisor on Page 1							
33	Total of (a)-(b)					0		
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)					0		
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.n)							
35	a. Transmission charges for all transmission transactions					$0		
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1					$0		

36a	c. Transmission charges from Schedules associated with Attachment GG (Note X)	$0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note Z)	$0
37	Total of (a)-(b)-(c)-(d)	$0

Note 4. Allowed ROE set to 12.38%.

Formula Rate – Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

ITC Midwest LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).
G Identified in Form 1 as being only transmission related.
H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.
I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:	FIT =	0.00%
	SIT =	0.00% (State Income Tax Rate or Composite SIT)
	p =	0.00% (percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O Enter dollar amounts.
P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation and 50 basis point adder for independence may be added to the allowed ROE up to the upper end of the zone of reasonableness established by FERC.
Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.
T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U Calculate using 13 month average balance.
V Calculate using average of beginning and end of year balances.
W Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.
X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Y Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

Z	Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
AA	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
AB	Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).
AC	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Company Name: ITC Midwest LLC

Cost Year: ____________________

Projected/Actual: ____________________

Attachment O-ITCM
Page 6 of 6

Depreciation Rates

		Account No.	Description	Depreciation Rates
1	Intangible Plant		Intangible Plant	
2				
3		303	Miscellaneous Intangible Plant (Note 1)	2.00%
4	Transmission Plant Accounts (Note 2)			
5		350	Land Rights	1.33%
6		352	Structures & Improvements	1.55%
7		353	Station Equipment	2.05%
8		354	Towers & Fixtures	1.22%
9		355	Poles & Fixtures	1.69%
10		356	Overhead Conductors & Devices	1.81%
11		357	Underground Conduit	1.57%
12		358	Underground Conductors & Devices	1.66%
13		359	Roads and Trails	1.33%
14	General Plant Accounts (Note 2)			
15		389	Land Rights	1.33%
16		390	Structures & Improvements	1.50%
17		391-A	Office Furniture & Equipment--	5.00%

	Equipment:	
391-B	Office Furn & Eq--Computers	20.00%
391-C	Office Furniture & Equipment--Software	20.00%
392	Transportation Equipment	20.13%
393	Stores Equipment	10.00%
394	Tools, Shop & Garage Equipment	10.00%
395	Laboratory Equipment	10.00%
396	Power Operated Equipment	6.36%
397	Communication Equipment	10.00%
398	General Miscellaneous Equipment	10.00%

Note 1: The amortization rate for Account 303, intangible plant, was authorized in FERC Docket No._____________

Note 2: Depreciation rates for transmission and general plant were authorized in FERC Docket No. ER10-2110, filed August 2, 2010, Order received September 2, 2010.

FERC rendition of the electronically filed tariff records in Docket No. ER16-00208-000
Filing Data:
CID: C001344
Filing Title: 2015-10-30_ITC, ITCM, METC Attachment O Revisions
Company Filing Identifier: 10756
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: FERC Electric Tariff
Tariff ID: 9
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
14, ITC Rate Formula Template, 31.0.0, A
Record Narative Name:
Tariff Record ID: 3816
Tariff Record Collation Value: 1079778304 Tariff Record Parent Identifier: 3803
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Exhibit B-4
of 5
Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/__
Utilizing FERC Form 1 Data

International Transmission Company

Line No.		(1) Total	(2) 12 months Allocator		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1.	GROSS REVENUE REQUIREMENT (Page 3, Line 31)				$0	$0	$0
	REVENUE CREDITS (Note T)						
2.	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3.	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)						

Line	Description				
		0	0	0	
6A	True-Up Adjustment [See Note 1.]	0			
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)	$0	$0	$0	
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)	0		0	
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)		0		
10	Plus 12 CP of Network Load not in Line 8 (Note C)		0		
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)		0		
12	Plus Contract Demand of firm P-T-P over one year		0		
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)		0		
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)		0		
15	Divisor (Sum Lines 8-14)	0	0	0	
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)				0.000
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)				0.000
					Peak Rate
	Off-Peak Rate				
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	$0.000			0.000
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	$0.000			0.000 Capped at weekly rate
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	$0.000			0.000 Capped at weekly and daily rates
21	FERC Annual Charge ($ / MWh) (Note E)	$0.000 Short Term			Short Term
22		$0.000 Long Term			Long Term

Note 1. Calculated in accordance with the International Transmission Company Annual Rate Calculation and True-up Procedures in Attachment O-International of this Tariff.

Attachment O-ITC

Exhibit B-4
Page 2 of 5

Formula Rate – Non-Levelized Template

Rate Formula
For the 12 months ended 12/31/___

Utilizing FERC Form 1 Data

International Transmission Company

Line No.	(1) Transmission RATE BASE:	(5) Adjustments	(6) Adjusted Amount	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator	(7) (Col. 3 times Col. 4)
	GROSS PLANT IN SERVICE (Note AA)						
1	Production			205.46.g		NA	
2	Transmission (Note U)	0	0	207.58.g		TP	0.00000
3	Distribution			207.75.g		NA	
4	General & Intangible (Note U)			205.5.g & 207.99.g		W/S	0.00000

		0		0				
5	Common				356.1		CE	0.00000
		0		0				
6	TOTAL GROSS PLANT (Sum Lines 1-5)					0	GP =	0.000%
		0	0	0				
	ACCUMULATED DEPRECIATION (Note AA)							
7	Production				219.20-24.c		NA	
8	Transmission (Note U)				219.25c		TP	0.00000
		0		0				
9	Distribution				219.26c		NA	
10	General & Intangible (Note U)				219.28c & 200.21.c		W/S	0.00000
		0		0				
11	Common				356.1		CE	0.00000
		0		0				
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)					0		
		0	0	0				
	NET PLANT IN SERVICE							
13	Production				(Line 1 – Line 7)	0		
14	Transmission				(Line 2 – Line 8)	0		
		0		0				
15	Distribution				(Line 3 – Line 9)	0		
16	General & Intangible				(Line 4 – Line 10)	0		
		0		0				
17	Common				(Line 5 – Line 11)	0		
		0		0				
18	TOTAL NET PLANT (Sum Lines 13-17)					0	NP =	0.000%
		0	0	0				
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative) (Note V)				273.8.k		NA	zero
		0						
20	Account No. 282 (enter negative) (Note V)				275.2.k		NP	0.00000
		0		0				
21	Account No. 283 (enter negative) (Note V) [See Note 2.]				277.9.k		NP	0.00000
		0		0				
22	Account No. 190 (Note V) [See Note 2.]				234.8.c		NP	0.00000
		0		0				
23	Account No. 255 (enter negative) (Note V)				267.8.h		NP	0.00000
		0		0				
23A	Account No. 182.3 Attm1 O Def				232.f			
		0		0				
23B	Account No. 114 ADIT Deferral				200.c.12			
		0		0				
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B)					0		
		0	0	0				
25	LAND HELD FOR FUTURE USE (Note V)				214.x.d (Note G)		TP	0.00000
		0		0				
	WORKING CAPITAL (Note H)							
26	CWC				calculated	0		
		0	0	0				
27	Materials & Supplies (Note G) (Note V)				227.8.c & .16.c		TP	0.00000
		0		0				
28	Prepayments (Account 165) (Note V)				111.57.c		GP	0.00000
		0		0				
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)					0		
		0	0	0				
30	RATE BASE (Sum Lines 18, 24, 25, & 29)					0		
		0	0	0				

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Rate Formula Template

Formula Rate -- Non-Levelized
For the 12 months ended 12/31/__

Utilizing FERC Form 1 Data
International Transmission Company

Line No.	(1)	(5) Transmission (Col. 3 times Col. 4)	(6) Adjustments	(7) Amount	(2) Form No. 1 Adjusted Page, Line, Col.	(3) Company Total	(4) Allocator
	O&M						
1	Transmission (See Note T)	0.00000	0		321.112.b	0	TE
2	Less Account 565	0.00000	0		321.96.b	0	TE
3	A&G	0.00000	0		323.197.b	0	W/S
4	Less FERC Annual Fees	0.00000	0			0	W/S
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)	0.00000	0			0	W/S
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)	0.00000	0			0	TP
6	Common	0.00000	0		356.1	0	CE
7	Transmission Lease Payments	1.00000	0				
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)	0	0	0		0	
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)						
9	Transmission	0.00000	0		336.7.b&c	0	TP
10	General & Intangible	0.00000	0		336.10.f & 336.1.f	0	W/S
11	Common	0.00000	0		336.11.b&c	0	CE
11A	Attachment O Deferral Adjustment	0		0	232.e		
11B	ADIT Adjustment	0		0	114.c.9		
12	TOTAL DEPRECIATION (Sum Lines 9-11B)	0	0	0		0	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	0.00000	0		263.i	0	W/S
14	Highway and vehicle	0.00000	0		263.i	0	W/S
15	PLANT RELATED						
16	Property	0.00000	0		263.i	0	GP
17	Gross Receipts	zero	0		263.i		NA
18	Other	0.00000	0		263.i	0	GP
19	Payments in lieu of taxes	0.00000	0			0	GP
20	TOTAL OTHER TAXES (Sum Lines 13-19)	0	0	0		0	

	INCOME TAXES (Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.00%	
22	CIT= (T/1-T) * (1-(WCLTD/R)) =			0.00%	
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30)				
	and FIT, SIT & p are as given in footnote K.				
23	1 / (1 - T) = (from Line 21)			0.0000	
24	Amortized Investment Tax Credit (266.8f) (enter negative)				
24a	(Excess)/Deficient Deferred Income Taxes (Note AB)				
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note AC)				
25	Income Tax Calculation = Line 22 * Line 28			0	NA
	0	0	0		
26	ITC adjustment (Line 23 * Line 24)			0	NP
	0.00000	0	0		
26a	(Excess)/Deficient Deffered Income Tax Adjustment (Line 23 x Line 24a)			0	NP
	0.00000	0	0		
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)			0	NP
	0.00000	0	0	0	
27	Total Income Taxes (Line 25 plus Line 26 + 26a + 26b)			0	
	0	0	0		
28	RETURN			0	NA
	0	0	0		
	[Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]				
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)			0	
	0	0	0		
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]			0	
	0	0	0		
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]			0	
	0	0	0		
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 – Line 30 – Line 30a)			0	
	0	0	0		

Note 3. Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Formula Rate -- Non-Levelized

For the 12 months ended 12/31/__
Utilizing FERC Form 1 Data
International Transmission Company

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES				
1	Total transmission plant (Page 2, Line 2, Column 3)	0			
2	Less transmission plant excluded from ISO rates (Note M)				
3	Less transmission plant included in OATT Ancillary Services (Note N)				
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3)	0			
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1)	0.00000			TP =
	TRANSMISSION EXPENSES				
6	Total transmission expenses (Page 3, Line 1, Column 3)	0			
7	Less transmission expenses included in OATT Ancillary Services (Note L)	0			
8	Included transmission expenses (Line 6 less Line 7)	0			
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6)	0.00000			
10	Percentage of transmission plant included in ISO Rates (Line 5)	0.00000			TP ·
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10)	0.00000			TE =

	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation
12	Production	354.20.b		0.00	0
13	Transmission	354.21.b		0.00	0
14	Distribution	354.23.b		0.00	0
15	Other	354.24, 25, 26.b		0.00	0
16	Total (Sum Lines 12-15)		0		0
	W&S Allocator ($/Allocation) = 0.00000	= WS			

	COMMON PLANT ALLOCATOR (CE) (Note O)		$	% Electric (Line 17 / Line 20)	W&S Allocator (Line 16)	CE
17	Electric	200.3.c		0.00000	* 0.00000	= 0.00000
18	Gas	201.3.d				
19	Water	201.3.e				
20	Total (Sum Lines 17-19)		0			

	RETURN (R)	(5) $	(6) Adjustments	(7) Adjusted Amount
21	Long Term Interest (117, sum of 62.c through 67.c)			0
22	Preferred Dividends (118.29c) (positive number)			0

Devolopment of Common Stock:

23 Proprietary Capital (112.16.c) (Note U)
0

24 Less Preferred Stock (Line 28) (Note U)
0 0

25 Less Account 216.1 (112.12.c) (enter negative) (Note U)
0

26 Common Stock (Sum Lines 23-25)
0 0 0

			$	%	Cost (Note P)
	Weighted				
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)	0.0000 = WCLTD		0%	0.0000
28	Preferred Stock (112.3.c) (Note U)	0.0000		0%	0.0000
29	Common Stock (Line 26) [See Note 4.]	0.0000	0	0%	0.1388
30	Total (Sum Lines 27-29)	0.0000 = R	0		

REVENUE CREDITS

ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)

Load

31 a. Bundled Non-RQ Sales for Resale (311.x.h)

32 b. Bundled Sales for Resale included in Divisor on Page 1

33 Total of (a)-(b)
0

34 ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)

ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.n)

35 a. Transmission charges for all transmission transactions
$0

36 b. Transmission charges for all transmission transactions included in Divisor on Page 1
$0

36a c. Transmission charges from Schedules associated with Attachment GG (Note X)
$0

36b d. Transmission charges from Schedules associated with Attachment MM (Note Z)
$0

37 Total of (a)-(b)-(c)-(d)
$0

Note 4. Allowed ROE set to 13.88%

Attachment O-ITC

Exhibit B-4

Formula Rate – Non-Levelized

For the 12 months ended 12/31/__

Rate Formula Template

Utilizing FERC Form 1 Data

International Transmission Company

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:	FIT =	0.00%
	SIT =	0.00% (State Income Tax Rate or Composite SIT)
	p =	0.00% (percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.

T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Calculate using 13 month average balance.

V Calculate using average of beginning and end of year balances.

W Pursuant to Attachment GG of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Y Pursuant to Attachment MM of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

Z Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

AA Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

AB Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).

AC Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
14A, ITC Depreciation Rates, 31.0.0, A
Record Narative Name:
Tariff Record ID: 10467
Tariff Record Collation Value: 1079778320 Tariff Record Parent Identifier: 3816
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Company Name: International Transmission Company

Cost Year: ____________________
Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description
1	Intangible Plant		
2			
3		303	Miscellaneous Intangible Plant (Note 1)
4			
5	Transmission Plant Accounts (Note 2)		
6			
7		350	Land Rights
8		352	Structures and improvements
9		353	Station Equipment
10		354	Towers & Fixtures
11		355	Poles & Fixtures (Note 1)
12		356	Overhead Conductors & Devices
13		357	Underground Conduit
14		358	Underground Conductors & Devices
15			
16	General Plant Accounts (Note 2)		

17		
18	390	Structures and improvements
19	391-A	Office Furniture & Equipment
20	391-B	Office Furn & Eq--Computers
21	391-C	Office Furniture & Equipment--Software
22	392	Transportation Equipment
23	393	Stores Equipment--10 year
24	394	Tools Shop & Garage Equipment
25	396	Power Operated Equipment
26	397	Communication Equipment
27	398	Miscellaneous Equipment
28		

29 Note 1: The amortization rate for Account 303, intangible plant, and the depreciation rate for Account 35
30 poles and fixtures were authorized in
31 FERC Docket No. ________________
32 Note 2: Depreciation rates for other transmission and general plant accounts were authorized
33 in FERC Docket No. ER09-1530, filed July 31, 2009, Order received September 22, 2009.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
15, METC Rate Formula Template, 33.0.0, A
Record Narative Name:
Tariff Record ID: 3831
Tariff Record Collation Value: 1079778816 Tariff Record Parent Identifier: 3803
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Attachment O-METC
Page 1 of 5

Formula Rate – Non-Levelized
For the 12 months ended 12/31/__

Rate Formula Template
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

Line No.				Allocated Amount	Total
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)			$0	
	REVENUE CREDITS (Note T)	Allocator			Total
2	Account No. 454 (Page 4, Line 34)	TP	0.00000	0	0
3	Account No. 456.1 (Page 4, Line 37)	TP	0.00000	0	0

4	Revenues from Grandfathered Interzonal Transactions TP 0.00000 0		0
5	Revenues from service provided by the ISO at a discount TP 0.00000 0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)	$0	
6A	True-Up Adjustment (See Note 1)	0	
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)	$0	
	DIVISOR		
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)	0	
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)	0	
10	Plus 12 CP of Network Load not in Line 8 (Note C)	0	
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year	0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)	0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)	0	
15	Divisor (Sum Lines 8-14)	0	
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)		0.000
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)		0.000
		Off-Peak Rate	Peak Rate
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)	$0.000	0.000
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)	$0.000	0.000 Capped at weekly rate
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4,160; Line 16 / 8,760 times 1,000)	$0.000	0.000 Capped at weekly and daily rates
21	FERC Annual Charge ($ / MWh) (Note E)	$0.000 Short Term	$0.000 Short Term
22		$0.000 Long Term	$0.000 Long Term

Note 1: Calculated in accordance with the Michigan Electric Transmission Company, LLC Annual Rate Calculation and True-up Procedures in Attachment O of this Tariff.

Formula Rate – Non-Levelized
Rate Formula Template
For the 12 months ended 12/31/__
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

Line No.	(1) RATE BASE:	(4) Allocator		(5) Transmission (Col. 3 times Col. 4)	(2) Form No. 1 Page, Line, Col.	(3) Company Total
	GROSS PLANT IN SERVICE (Note BB)					
1	Production	NA	zero	0	205.46.g	0
2	Transmission (Note V)	TP	0.00000	0	207.58.g	0
3	Distribution	NA	zero	0	207.75.g	0
4	General & Intangible (Note V)	W/S	0.00000	0	205.5.g & 207.99.g	0
5	Common	CE	0.00000	0	356.1	0
6	TOTAL GROSS PLANT (Sum Lines 1-5)	GP =	0.000%	0		0
	ACCUMULATED DEPRECIATION (Note BB)					
7	Production	NA	zero	0	219.20-24.c	0
8	Transmission (Note V)	TP	0.00000	0	219.25c	0
9	Distribution	NA	zero	0	219.26c	0
10	General & Intangible (Note V)	W/S	0.00000	0	219.28c & 200.21.c	0
11	Common	CE	0.00000	0	356.1	0
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11)			0		0
	NET PLANT IN SERVICE					
13	Production			0	(Line 1 – Line 7)	0
14	Transmission (Note V)			0	(Line 2 – Line 8)	0
15	Distribution			0	(Line 3 – Line 9)	0
16	General & Intangible (Note V)			0	(Line 4 – Line 10)	0
17	Common			0	(Line 5 – Line 11)	0
18	TOTAL NET PLANT (Sum Lines 13-17)	NP =	0.000%	0		0
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative) (Note W)	NA	zero	0	273.8.k	0
20	Account No. 282 (enter negative) (Note W)	NP	0.00000	0	275.2.k	0
21	Account No. 283 (enter negative) (Note W)	NP	0.00000	0	[See Note 2.] 277.9.k	0
22	Account No. 190 (Note W) [See Note 2.]	NP	0.00000	0	234.8.c	0
23	Account No. 255 (enter negative) (Note W)	NP	0.00000	0	267.8.h	0
23a	Account No. 182.3 Deferral	NP	0.00000	0		0
23b	Account No. 114 ADIT	NP	0.00000	0		0
23c	Amortization of Deferral	NP	0.00000	0		0
23d	Amortization of ADIT	NP	0.00000	0		0
24	TOTAL ADJUSTMENTS (Sum Lines 19-23d)			0		0
25	LAND HELD FOR FUTURE USE (Note W)	TP	0.00000	0	214.x.d (Note G)	0

Line					
	WORKING CAPITAL (Note H)				
26	CWC			calculated	0
			0		
27	Materials & Supplies (Note G) (Note W)			227.8.c & .16.c	0
	TP	0.00000	0		
28	Prepayments (Account 165) (Note W)			111.57.c	0
	GP	0.00000	0		
29	TOTAL WORKING CAPITAL (Sum Lines 26-28)				0
			0		
30	RATE BASE (Sum Lines 18, 24, 25, & 29)				0
			0		

Note 2: Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Attachment O-METC
Page 3 of 5

Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/__
Utilizing FERC Form 1 Data
Michigan Electric Transmission Company, LLC

Line No.	(1)	(4)	(5) Transmission (Col. 3 times Col. 4)	(2) Form No. 1 Page, Line, Col.	(3) Company Total
	Allocator				
	O&M				
1	Transmission			321.112.b	0
	TE	0.00000	0		
2	Less Account 565			321.96.b	0
	TE	0.00000	0		
2a	Customer Records			322.164.b	0
	W/S	0.00000	0		
3	A&G			323.197.b	0
	W/S	0.00000	0		
4	Less FERC Annual Fees				0
	W/S	0.00000	0		
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)				0
	W/S	0.00000	0		
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)				0
	TP	0.00000	0		
6	Common			356.1	0
	CE	0.00000	0		
7	Transmission Lease Payments				0
		1.00000	0		
8	TOTAL O&M (Sum Lines 1, 2a, 3, 5a, 6, 7 less Lines 2, 4, 5)				0
			0		
	DEPRECIATION & AMORTIZATION EXPENSE (Note BB)				
9	Transmission			336.7.b	0
	TP	0.00000	0		
10	General & Intangible			336.10.f & 336.1.f	0
	W/S	0.00000	0		
11	Common			336.11.b	0
	CE	0.00000	0		
11a	Regulatory Deferral Amortization (Note J-a)				0
			0		
11b	ADIT Amortization				0
			0		
12	TOTAL DEPRECIATION (Sum Lines 9-11b)				0
			0		
	TAXES OTHER THAN INCOME TAXES (Note J)				
	LABOR RELATED				
13	Payroll			263.3,4,8.i	0
	W/S	0.00000	0		
14	Highway and vehicle			263.i	0
	W/S	0.00000	0		
15	PLANT RELATED				
16	Property			263.i	0
	GP	0.00000	0		
17	Gross Receipts			263.i	0
	NA	zero	0		
18	Other			263.i	0
	GP	0.00000	0		
19	Payments in lieu of taxes				0
	GP	0.00000	0		
20	TOTAL OTHER TAXES (Sum Lines 13-19)				0
			0		
	INCOME TAXES (Note K)				

21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	0.00%
22	CIT = (T/1-T) * (1-(WCLTD/R)) =	0.00%
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30)	
	and FIT, SIT & p are as given in footnote K.	
23	1 / (1 - T) = (from Line 21)	0.0000
24	Amortized Investment Tax Credit (266.8f) (enter negative)	0
24a	(Excess)/Deficient Deferred Income Tax (Note CC)	
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note DD)	
25	Income Tax Calculation = Line 22 * Line 28	0
	NA zero 0	
26	ITC adjustment (Line 23 * Line 24)	0
	NP 0.00000 0	
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)	0
	NP 0.00000 0	
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)	0
	NP 0.00000 0	
27	Total Income Taxes (Line 25 plus Line 26 plus 26a plus 26b)	0
	0	
28	RETURN	0
	NA 0	
	[Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]	
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)	0
	0	
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note X)	0
	[Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	
	0	
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Z)	0
	[Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	
	0	
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 - Line 30 - Line 30a)	0
	0	

Formula Rate -- Non-Levelized
Rate Formula Template
For the 12 months ended 12/31/__

Michigan Electric Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTERS

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES				
1	Total transmission plant (Page 2, Line 2, Column 3) 0				
2	Less transmission plant excluded from ISO rates (Note M) 0				
3	Less transmission plant included in OATT Ancillary Services (Note N) 0				
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3) 0				
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1) 0.00000				TP =
	TRANSMISSION EXPENSES				
6	Total transmission expenses (Page 3, Line 1, Column 3) 0				
7	Less transmission expenses included in OATT Ancillary Services (Note L) 0				
8	Included transmission expenses (Line 6 less Line 7) 0				
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6) 0.00000				
10	Percentage of transmission plant included in ISO Rates (Line 5) 0.00000				TP
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10) 0.00000				TE =

	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation
12	Production	354.20.b	0	0.00	0
13	Transmission	354.21.b	0	0.00	0
14	Distribution	354.23.b	0	0.00	0
	W&S Allocator				
15	Other	354.24, 25, 26, 27.b	0	0.00	0
	($/Allocation)				
16	Total (Sum Lines 12-15) = 0.00000 = WS		0		0

	COMMON PLANT ALLOCATOR (CE) (Note O)		$	% Electric
	W&S Allocator			
17	Electric (Line 16) CE	200.3.c	0	(Line 17 / Line 20)
18	Gas * 0.00000 = 0.00000	201.3.d	0	0.00000
19	Water	201.3.e	0	
20	Total (Sum Lines 17-19)		0	

	RETURN (R)	$
21	Long Term Interest (117, sum of 62.c through 67.c) see footnote to FERC Form 1	$0
22	Preferred Dividends (118.29c) (positive number)	0
	Development of Common Stock:	
23	Proprietary Capital (112.16.c) (Note V)	0
24	Less Preferred Stock (Line 28) (Note V)	0
25	Less Account 216.1 (112.12.c) (enter negative) (Note V)	0
25a	Less 2003 Equity Adjustment (253,3,b) (enter negative) (Note V)	0
26	Common Stock (Sum Lines 23-25a)	0

	Weighted	$	%	Cost (Note P)
27	Long Term Debt (112, sum of 18.c through 21.c) (Note V) 0.0000 = WCLTD	0	0%	0.0000
28	Preferred Stock (112.3.c) (Note V) 0.0000	0	0%	0.0000
29	Common Stock (Line 26) 0.0000	0	0%	0.0000
30	Total (Sum Lines 27-29) 0.0000 = R	0		

REVENUE CREDITS

ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)

Load

31	a. Bundled Non-RQ Sales for Resale (311.x.h)	0
32	b. Bundled Sales for Resale included in Divisor on Page 1	0

33	Total of (a)-(b) 0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) $0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)
35	a. Transmission charges for all transmission transactions $0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1 $0
36a	c. Transmission charges from Schedules associated with Attachment GG (Note Y) $0
36b	d. Transmission charges from Schedules associated with Attachment MM (Note AA) $0
37	Total of (a)-(b)-(c)-(d) $0

Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/__

Utilizing FERC Form 1 Data

Michigan Electric Transmission Company, LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as reported on Page 400, Column b of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 Line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

I-a For the rate period June 1, 2006 through May 31, 2007, this amount will reflect an adjustment (positive or negative) equal to the true-up amount, including interest, determined pursuant to the methodology approved in Docket No. ER06-xx, to eliminate the rate impact of the differences caused by the use of a projected year 2005 deferral balance.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:	FIT =	0.00%	
	SIT =	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts.

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation may be added to the ROE up to the upper end of the zone of reasonableness established by FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.

T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

V Calculate using 13 month average balance.

W Calculate using average of beginning and end of year balances.

X Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

Y Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Z Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

AA Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

BB Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

CC Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).

DD Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one of more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
15A, METC Depreciation Rates, 31.0.0, A
Record Narative Name:
Tariff Record ID: 10469
Tariff Record Collation Value: 1079778832 Tariff Record Parent Identifier: 3831
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Company Name: Michigan Electric Transmission Compamy

Cost Year: ____________________

Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description	Depı
1	Intangible Plant			
2		303	Miscellaneous Intangible Plant	
3				
4	Transmission Plant Accounts			
5		350	Land Rights	
6		352	Structures & Improvements	
7		353	Station Equipment	
8		354	Towers & Fixtures	
9		355	Poles & Fixtures	
10		356	Overhead Conductors & Devices	
11		357	Underground Conduit	
12		358	Underground Conductors & Devices	
13		359	Roads and Trails	
14				
15	General Plant Accounts			
16		390	Structures & Improvements	
17		391-A	Office Furniture & Equipment--Software	
18		391-B	Office Furn & Eq--Equipment	
19		391-C	Office Furniture & Equipment--Computers	
20		392	Transportation Equipment	
21		393	Stores Equipment	

22	394	Tools, Shop & Garage Equipment
23	395	Laboratory Equipment
24	396	Power Operated Equipment
25	397	Communication Equipment
26	398	General Miscellaneous Equipment
27		

28 Note: Depreciation/amortization rates for intangible, transmission and general plant were authorized
29 in FERC Docket No. ER10-185, filed October 30, 2009, Order received December 18, 2009.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
17, ITCM Rate Formula Template, 35.0.0, A
Record Narative Name:
Tariff Record ID: 4485
Tariff Record Collation Value: 1079779840 Tariff Record Parent Identifier: 3803
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Attachment O-ITCM
Page 1 of 5

Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/__
Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.		(1) Total	(2) 12 months Allocator		(3) Allocated Amount	(4) Adjustments	(5) Adjusted Allocated Amount
1	GROSS REVENUE REQUIREMENT (Page 3, Line 31)				$0	$0	$0
	REVENUE CREDITS (Note T)						
2	Account No. 454 (Page 4, Line 34)	0	TP	0.00000	0	0	0
3	Account No. 456.1 (Page 4, Line 37)	0	TP	0.00000	0		0
4	Revenues from Grandfathered Interzonal Transactions	0	TP	0.00000	0		0
5	Revenues from service provided by the ISO at a discount	0	TP	0.00000	0		0
6	TOTAL REVENUE CREDITS (Sum Lines 2-5)				0	0	0
6A	True-Up Adjustment [See Note 1.]				0		0
7	NET REVENUE REQUIREMENT (Line 1 minus Line 6 plus Line 6A)				$0	$0	$0
	DIVISOR						
8	Average of 12 coincident system peaks for requirements (RQ) service (Note A)				0		0
9	Plus 12 CP of firm bundled sales over one year not in Line 8 (Note B)					0	
10	Plus 12 CP of Network Load not in Line 8 (Note C)						

		0	
11	Less 12 CP of firm P-T-P over one year (enter negative) (Note D)	0	
12	Plus Contract Demand of firm P-T-P over one year	0	
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)	0	
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)	0	
15	Divisor (Sum Lines 8-14)	0 0 0	
16	Annual Cost ($ / kW / Yr) (Line 7 / Line 15)		0.000
17	Network & P-to-P Rate ($ / kW / Mo) (Line 16 / 12)		0.000
			Peak Rate
	Off-Peak Rate		
18	Point-To-Point Rate ($ / kW / Wk) (Line 16 / 52; Line 16 / 52)		0.000
	$0.000		
19	Point-To-Point Rate ($ / kW / Day) (Line 16 / 260; Line 16 / 365)		0.000 Capped at weekly rate
	$0.000		
20	Point-To-Point Rate ($ / MWh) (Line 16 / 4160; Line 16 / 8760 * 1000)		0.000 Capped at weekly and daily rates
	$0.000		
21	FERC Annual Charge ($ / MWh) (Note E)		Short Term
	$0.000 Short Term		
22			Long Term
	$0.000 Long Term		

Note 1. Calculated in accordance with the ITC Midwest, LLC Annual Rate Calculation and True-up Procedures in Attachment O-Midwest of this Tariff.

Formula Rate – Non-Levelized

For the 12 months ended 12/31/__

Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.	(1) (5) Transmission RATE BASE: (Col. 3 times Col. 4)	(6) Adjustments	Adjusted Amount	(2) (7) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator	
	GROSS PLANT IN SERVICE (Note AA)						
1	Production	0		205.46.g		NA	
2	Transmission (Note U) 0		0	207.58.g	0	TP	0.00000
3	Distribution			207.75.g		NA	
4	General & Intangible (Note U) 0		0	205.5.g & 207.99.g	0	W/S	0.00000
5	Common 0		0	356.1		CE	0.00000
6	TOTAL GROSS PLANT (Sum Lines 1-5) 0	0	0		0	GP =	0.000%
	ACCUMULATED DEPRECIATION (Note AA)						
7	Production			219.20-24.c		NA	
8	Transmission (Note U) 0		0	219.25c	0	TP	0.00000
9	Distribution			219.26c		NA	
10	General & Intangible (Note U) 0		0	219.28c & 200.21.c	0	W/S	0.00000
11	Common 0		0	356.1		CE	0.00000
12	TOTAL ACCUM. DEPRECIATION (Sum Lines 7-11) 0	0	0		0		
	NET PLANT IN SERVICE						
13	Production			(Line 1-Line 7)	0		
14	Transmission 0		0	(Line 2-Line 8)	0		
15	Distribution			(Line 3-Line 9)			
16	General & Intangible 0		0	(Line 4-Line 10)	0		
17	Common 0		0	(Line 5-Line 11)	0		
18	TOTAL NET PLANT (Sum Lines 13-17) 0	0	0		0	NP =	0.000%
	ADJUSTMENTS TO RATE BASE (Note F)						
19	Account No. 281 (enter negative) (Note V) 0			273.8.k		NA	zero
20	Account No. 282 (enter negative) (Note V) 0		0	275.2.k		NP	0.00000
21	Account No. 283 (enter negative) (Note V) 0		0	277.9.k		NP	0.00000
22	Account No. 190 (Note V) [See Note 2.] 0		0	234.8.c		NP	0.00000
23	Account No. 255 (enter negative) (Note V) 0		0	267.8.h		NP	0.00000
24	TOTAL ADJUSTMENTS (Sum Lines 19-23B) 0	0	0		0		
25	LAND HELD FOR FUTURE USE (Note V) 0		0	214.x.d (Note Q)		TP	0.00000
	WORKING CAPITAL (Note H)						
26	CWC 0	0	0	calculated	0		
27	Materials & Supplies (Note G) (Note V) 0		0	227.8.c & 16.c	0	TP	0.00000
28	Prepayments (Account 165) (Note V) 0		0	111.57.c		GP	0.00000
29	TOTAL WORKING CAPITAL (Sum Lines 26-28) 0	0	0		0		
30	RATE BASE (Sum Lines 18, 24, 25, & 29)				0		

0	0	0

Note 2. Excludes deferred taxes associated with the True-up Adjustment that are not otherwise included in rate base.

Formula Rate -- Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/__

Utilizing FERC Form 1 Data

ITC Midwest LLC

Line No.	(1) Transmission O&M	(5) (Col. 3 times Col. 4)	(6) Adjustments Amount	(2) (7) Form No. 1 Adjusted Page, Line, Col.	(3) Company Total	(4) Allocator
1	Transmission (See Note 3.)	0.00000	0	321.112.b 0		TE
2	Less Account 565	0.00000	0	321.96.b 0		TE
3	A&G	0.00000	0	323.197.b 0		W/S
4	Less FERC Annual Fees	0.00000	0	0		W/S
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note 1)	0.00000	0	0		W/S
5a	Plus Transmission Related Reg. Comm. Exp. (Note 1)	0.00000	0	0		TP
6	Common	0.00000	0	356.1 0		CE
7	Transmission Lease Payments	1.00000	0			
8	TOTAL O&M (Sum Lines 1, 3, 5a, 6, 7 less Lines 2, 4, 5)	0	0	0	0	
	DEPRECIATION & AMORTIZATION EXPENSE (Note AA)					
9	Transmission	0.00000	0	336.7.b&c 0		TP
10	General & Intangible	0.00000	0	336.10.f & 336.1.f 0		W/S
11	Common	0.00000	0	336.11.b&c 0		CE
12	TOTAL DEPRECIATION (Sum Lines 9-11B)	0	0	0	0	
	TAXES OTHER THAN INCOME TAXES (Note 3)					
	LABOR RELATED					
13	Payroll	0.00000	0	263.i 0	0	W/S
14	Highway and vehicle	0.00000	0	263.i 0		W/S
15	PLANT RELATED					
16	Property	0.00000	0	263.i 0	0	GP
17	Gross Receipts	zero	0	263.i		NA
18	Other			263.i		GP

	0.00000 0 0		
19	Payments in lieu of taxes		GP
	0.00000 0 0		
20	TOTAL OTHER TAXES (Sum Lines 13-19)	0	
	0 0 0		
	INCOME TAXES (Note K)		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	0.00%	
22	CIT=(T/1-T) * (1-(WCLTD/R)) =	0.00%	
	where WCLTD= (Page 4, Line 27) and R= (Page 4, Line 30)		
	and FIT, SIT & p are as given in footnote K.		
23	1 / (1 - T) = (from Line 21)	0.0000	
24	Amortized Investment Tax Credit (266.8f) (enter negative)		
24a	(Excess)/Deficient Deferred Income Taxes (Note AB)		
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note AC)		
25	Income Tax Calculation = Line 22 * Line 28	0	NA
	0 0 0		
26	ITC adjustment (Line 23 * Line 24)		NP
	0.00000 0 0		
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 x Line 24a)	0	NP
	0.00000 0 0		
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 x Line 24b)	0	NP
	0.00000 0 0		
27	Total Income Taxes (Line 25 + Line 26 + 26a + 26b)	0	NP
	0 0 0		
28	RETURN	0	NA
	0 0 0		
	[Rate Base (Page 2, Line 30) * Rate of Return (Page 4, Line 30)]		
29	REV. REQUIREMENT (Sum Lines 8, 12, 20, 27, 28)	0	
	0 0 0		
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, Page 2, Line 3, Column 10] (Note W) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment GG]	0	
	0 0 0		
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, Page 2, Line 3, Column 14] (Note Y) [Revenue Requirement for facilities included on Page 2, Line 2, and also included in Attachment MM]	0	
	0 0 0		
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (Line 29 - Line 30 - Line 30a)	0	
	0 0 0		

Note 3. Adjustments to Line 1 will equal the sum of the amounts on ITC's Report on FERC Form No. 1 for Customer Accounts Expenses [FERC Form No. 1, 323.164.b], Customer Service and Informational Expenses [FERC Form No. 1, 323.171.b], and Sales Expenses [FERC Form No. 1, 323.178.b] that are not otherwise recoverable through some other tariff. Adjustments to be made before calculation of allocator for Line 1, Column (4).

Formula Rate – Non-Levelized

Rate Formula Template

For the 12 months ended 12/31__
Utilizing FERC Form 1 Data

ITC Midwest LLC
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES	
1	Total transmission plant (Page 2, Line 2, Column 3) 0	
2	Less transmission plant excluded from ISO rates (Note M)	
3	Less transmission plant included in OATT Ancillary Services (Note N)	
4	Transmission plant included in ISO rates (Line 1 less Lines 2 & 3) 0	TP =
5	Percentage of transmission plant included in ISO Rates (Line 4 divided by Line 1) 0.00000	
	TRANSMISSION EXPENSES	
6	Total transmission expenses (Page 3, Line 1, Column 3) 0	
7	Less transmission expenses included in OATT Ancillary Services (Note L) 0	
8	Included transmission expenses (Line 6 less Line 7) 0	
9	Percentage of transmission expenses after adjustment (Line 8 divided by Line 6) 0.00000	TP
10	Percentage of transmission plant included in ISO Rates (Line 5) 0.00000	TE =
11	Percentage of transmission expenses included in ISO Rates (Line 9 times Line 10) 0.00000	

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation
12	Production	354.20.b		0.00	0
13	Transmission	354.21.b	0	0.00	0
14	Distribution	354.23.b		0.00	0
15	Other	354.24, 25, 26.b		0.00	0
16	Total (Sum Lines 12-15)		0		0

W&S Allocator
($/Allocation)

= 0.00000 = WS
COMMON PLANT ALLOCATOR (CE) (Note O) $ % Electric
W&S Allocator
17 Electric 200.3.c 0 (Line 17 / Line 20)
(Line 16) CE 0.00000
18 Gas 201.3.d
* 0.00000 = 0.00000
19 Water 201.3.c 0
(7)
20 Total (Sum Lines 17-19) 0
(5) (6) Adjusted
RETURN (R)
$ Adjustments Amount
21 Long Term Interest (117, sum of 62.c through 67.c)
0 0
22 Preferred Dividends (118.29c) (positive number)
0
Development of Common Stock:
23 Proprietary Capital (112.16.c) (Note U)
0 0
24 Less Preferred Stock (Line 28) (Note U)
0 0
25 Less Account 216.1 (112.12.c) (enter negative) (Note U)
0
26 Common Stock (Sum Lines 23-25)
0 0 0

	Weighted	$	%	Cost (Note P)
27	Long Term Debt (112, sum of 18.c through 21.c) (Note U)	0	0%	0.0000
	0.0000 = WCLTD			
28	Preferred Stock (112.3.c) (Note U)		0%	0.0000
	0.0000			
29	Common Stock (Line 26) [See Note 4.]	0	0%	0.0000
	0.0000			
30	Total (Sum Lines 27-29)	0		
	0.0000 = R			

REVENUE CREDITS
ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)
Load
31 a. Bundled Non-RQ Sales for Resale (311.x.h)
32 b. Bundled Sales for Resale included in Divisor on Page 1
33 Total of (a)-(b)
0
34 ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)
0
ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (330.x.n)
35 a. Transmission charges for all transmission transactions
$0
36 b. Transmission charges for all transmission transactions included in Divisor on Page 1
$0
36a c. Transmission charges from Schedules associated with Attachment GG (Note X)
$0
36b d. Transmission charges from Schedules associated with Attachment MM (Note Z)
$0
37 Total of (a)-(b)-(c)-(d)
$0

Note 4. Allowed ROE set to 12.38%

Formula Rate -- Non-Levelized
Formula Template

For the 12 months ended 12/31/___

Utilizing FERC Form 1 Data

ITC Midwest LLC

General Note: References to pages in this formulary rate are indicated as: (Page #, Line #, Col. #)
References to data from FERC Form 1 are indicated as: #.y.x (Page, Line, Column)

Note Letter

A Peak as would be reported on Page 401, Column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
B Labeled LF, LU, IF, IU on Pages 310-311 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
C Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
D Labeled LF on Page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.
E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109.
Exclude ADIT balances when the associated income tax consequences have been paid by others.
Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
The calculation of ADIT in the annual true-up calculation will use the beginning-of-year balances and end-of-year balances; the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation section 1.167(l)-1(h)(6).
G Identified in Form 1 as being only transmission related.
H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at Page 3, Line 8, Column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 Line 57 in the Form 1.
I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes." If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (Page 3, Line 26).

Inputs Required:	FIT =	0.00%
	SIT =	0.00% (State Income Tax Rate or Composite SIT)
	p =	0.00% (percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O Enter dollar amounts.
P Debt cost rate = long-term interest (Line 21) / long term debt (Line 27). Preferred cost rate = preferred dividends (Line 22) / preferred outstanding (Line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation and 50 basis point adder for independence may be added to the allowed ROE up to the upper end of the zone of reasonableness established by FERC.
Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in Line 4, Page 1 and the loads are included in Line 13, Page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in Line 4, Page 1 nor are the loads included in Line 13, Page 1.
T The revenues credited on Page 1 Lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U Calculate using 13 month average balance.
V Calculate using average of beginning and end of year balances.
W Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.
X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Y Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.
Z Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
AA Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
AB Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T) (page 3, line 26a).
AC Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/1-T) (page 3, line 26b).

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
17A, ITCM Depreciation Rates, 31.0.0, A
Record Narative Name:
Tariff Record ID: 10468
Tariff Record Collation Value: 1079779856 Tariff Record Parent Identifier: 4485
Proposed Date: 2016-01-01
Priority Order: 1000000000
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

Company Name: ITC Midwest LLC

Cost Year: ____________________

Projected/Actual: ____________________

Depreciation Rates

		Account No.	Description	D
1	Intangible Plant		Intangible Plant	
2				
3		303	Miscellaneous Intangible Plant (Note 1)	
4	Transmission Plant Accounts (Note 2)			
5		350	Land Rights	
6		352	Structures & Improvements	
7		353	Station Equipment	
8		354	Towers & Fixtures	
9		355	Poles & Fixtures	
10		356	Overhead Conductors & Devices	
11		357	Underground Conduit	
12		358	Underground Conductors & Devices	
13		359	Roads and Trails	
14	General Plant Accounts (Note 2)			
15		389	Land Rights	
16		390	Structures & Improvements	
17		391-A	Office Furniture & Equipment--Equipment	
18		391-B	Office Furn & Eq--Computers	
19		391-C	Office Furniture & Equipment--Software	
20		392	Transportation Equipment	

393 Stores Equipment
394 Tools, Shop & Garage Equipment
395 Laboratory Equipment
396 Power Operated Equipment
397 Communication Equipment
398 General Miscellaneous Equipment

Note 1: The amortization rate for Account 303, intangible plant, was authorized in FERC Docket No.____________

Note 2: Depreciation rates for transmission and general plant were authorized in FERC Docket No. ER10-2110, filed August 2, 2010, Order received September 2, 2010.

Document Content(s)

Appendix 17 – November 20, 2015 AECS Comments on ITC Attachment O Modifications Request (Docket No. ER16-208)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent Transmission System Operator, Inc. on behalf of International Transmission Company d/b/a ITCTransmission, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC	))))))	Docket No. ER16-208-000

MOTION TO INTERVENE AND COMMENTS OF ALLIANT ENERGY CORPORATE SERVICES, INC.

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. §§ 385.212 and 385.214, Alliant Energy Corporate Services, Inc. ("Alliant Energy") respectfully files this motion to intervene and provide comments in the above-captioned docket. Although the comments filed herein are generally supportive of the filing, Alliant Energy respectfully requests clarification on a number of points as discussed further below.

I. Communications

Alliant Energy requests that all communications regarding this motion to intervene and comments be addressed to the following persons:

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.
Street: 4902 North Biltmore Lane
Madison, WI 53718
Telephone: 608-458-6217
E-Mail: CortlandtChoate@AlliantEnergy.com

Angela M. Cavallucci
Regulatory Relations Manager
Alliant Energy Corporate Services, Inc.
Street: 801 Pennsylvania Avenue, NW
Washington, DC 20004
Telephone: 202-347-8136
E-Mail: AngelaCavallucci@AlliantEnergy.com

Alliant Energy also requests that Mr. Choate and Ms. Cavallucci be placed on the Commission's official service list for this docket.

II. Motion to Intervene

Alliant Energy is a service company affiliate of Interstate Power and Light Company ("Interstate") and Wisconsin Power and Light Company ("WPL") (collectively, "Alliant Energy Operating Companies"). Interstate is a Load Serving Entity ("LSE") that owns and operates electric facilities engaged in the generation, purchase, distribution, and sale of electric power and energy in Iowa. WPL is an LSE that owns and operates electric facilities engaged in the generation, purchase, distribution, and sale of electric power and energy in Wisconsin. Neither of the Alliant Energy Operating Companies owns or operates transmission facilities. The Alliant Energy Operating Companies are MISO market participants and incur costs associated with the purchase of transmission, capacity, energy and ancillary market service within the MISO market.

Alliant Energy has a direct and substantial interest in this docket, and requests participation because the Alliant Energy Operating Companies will be directly affected by the outcome of this proceeding as Alliant Energy affiliates are transmission customers of ITC Midwest LLC ("ITC Midwest"). Alliant Energy's participation is in the public interest due to the Alliant Energy Operating Companies' unique obligations as public utilities providing the sole source of electric service in their service territories. No other party can adequately represent Alliant Energy's and the Alliant Energy Operating Companies' interests before the Commission.

III. Background

ITC Midwest uses Attachment O of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") to establish its forward-looking formula rates. Attachment O allows MISO Transmission Owners to recover their annual revenue requirements pursuant to which they establish charges for transmission service for facilities that the transmission owner owns, but which are under MISO functional control. The resulting rates are then posted on MISO's Open Access Same-Time Information System ("OASIS") each year. Completion of the annual Attachment O process results in the development of the network transmission service revenue requirement for the particular calendar year in question. This allows for adjustment of transmission rates to reflect changing operational data and financial performance, including the amount of network load on the transmission system, operating expenses and capital expenditures.

In the instant filing, International Transmission Company ("ITC"), on behalf of ITC Midwest and its other subsidiaries, proposes a number of changes to its Attachment O formula rate templates. The proposed changes are as follows:

> 1) recover income tax expense associated with permanent book/tax differences, the effects of after-tax accounting for deferred taxes associated with the equity component of the Allowance for Funds Used During Construction ("AFUDC equity"), and excess/deficient deferred income taxes resulting from tax law or rate changes; 2) exclude deferred income tax balances from the calculation of rate base when the associated income tax consequences have been paid by others; 3) explain how [the ITC companies] will implement Internal Revenue Service ("IRS") guidance on tax normalization issues; and 4) propose changes in the allocators for materials and supplies ("M&S") and Regulatory Commission expenses. ... ITC Midwest also seek[s] Commission authorization for the use of a 2% amortization rate for intangible plant[.]"[1]

ITC requests an effective date of January 1, 2016, for the proposed Attachment O template changes.

IV. Comments

A. Alliant Energy is supportive of ITC's proposed changes related to the treatment of Contributions in Aid of Construction ("CIAC") as the changes will result in proper accounting of Accumulated Deferred Income Taxes ("ADIT") associated with these transactions, but requests that the Commission require ITC to provide further information to allow parties to completely understand and interpret the requested Attachment O changes.

As explained in the instant filing, ITC may receive CIAC from interconnection customers in situations where the MISO Tariff provides for participant funding of transmission facilities.[2] If the CIAC does not qualify as a contribution to capital, ITC may charge interconnection customers a tax gross up for the income tax consequences in addition to the amount paid for the interconnection facilities or network upgrades as provided in Section 5.17.4 of the *pro forma* FERC generator interconnection agreement.[3] As noted by ITC, the ADIT associated with these tax consequences have already been paid by the interconnection customer under the existing Attachment O template, and thus have been inappropriately included in rate base by ITC. The result is that ITC's customers have been paying higher costs due to this double counting. Alliant Energy agrees that the past treatment of ADIT associated with these transactions was incorrect and that ITC needs to refund the disparity to its customers in order to reflect proper accounting.

[1] ITC Transmittal at 2.
[2] ITC Transmittal at 9.
[3] *Id.*

ITC indicated in the instant filing that it will provide work papers for the projected refund amounts at a later date through the reposting of future formula rate projections.[4] While Alliant Energy appreciates ITC's future commitment, Alliant Energy requests that ITC supplement the instant filing with refund calculation work papers so that it may more fully understand this issue and ITC's assessments. Alliant Energy posits that, without proper documentation, Alliant Energy and other interested parties cannot fully interpret and understand the impacts of ITC's proposed correction.

Notwithstanding the request for additional work papers, Alliant Energy supports ITC's proposed Attachment O template changes as well as its rationale in the interest of supplying timely refunds to ITC customers. The potential refund for customers of ITC Midwest – of which Interstate comprises a large majority of ITC Midwest customer load – for this particular change is substantial – estimated at nearly $6.56 million (inclusive of interest) for the period 2004 through 2014, and a projected refund of $1.68 million (inclusive of interest) for the 2015 period.[5]

B. Alliant Energy also requests further clarification regarding ITC's proposed changes to the recovery of income taxes on permanent differences and the effects of after-tax accounting for deferred taxes associated with AFUDC equity.

In the instant filing, ITC proposes to adjust the income tax calculation in the Attachment O templates to provide for recovery of permanent income tax differences that are associated with items included in the Attachment O revenue requirement, as well as for the effect of after-tax accounting for deferred taxes associated with AFUDC equity.[6] Alliant Energy does not oppose ITC's proposed change; however, it requests clarification concerning the specific permanent income tax differences ITC proposes to include, that are in addition to AFUDC equity.

V. Conclusion

WHEREFORE, for the reasons discussed above, Alliant Energy respectfully requests that the Commission grant its motion to intervene in this proceeding and consider its comments herein.

---

[4] *Id.*
[5] *Id.*
[6] ITC Transmittal at 7.

Respectfully submitted,

Alliant Energy Corporate Services, Inc.

/s/

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.

November 20, 2015

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have on this 20th day of November 20, 2015, caused a copy of the foregoing Comments of Alliant Energy Corporate Services, Inc. to be sent to each person designated on the official service list compiled by the Secretary of the Commission in Docket No. ER16-208-000.

/s/ Cortlandt C. Choate, Jr.

Cortlandt C. Choate, Jr.
Senior Attorney
Alliant Energy Corporate Services, Inc.

Document Content(s)

Appendix 18 – June 29, 2015 IPL Information Request

ALLIANT ENERGY

Alliant Energy
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

1-800-ALLIANT (1-800-255-4268)
alliantenergy.com

June 29, 2015

To: misoformularates@itctransco.com

Alliant Energy – Interstate Power & Light Co. (IPL) has the following questions related to discussion at the Spring 2015 ITC Midwest Partners in Business meeting held in Cedar Rapids, IA on May 13, 2015 and generally regarding costs impacting customers of ITC Midwest.

1. Referencing the most recent MVP Dashboard of MVP Project Status as of April 2015 found at https://www.misoenergy.org/Library/Repository/Study/MTEP/MVP%20Portfolio%20Triennial%20Review/MVP%20Dashboard.pdf, please explain the increased cost under the column Cost, Q1 2015 compared to the MTEP Approved cost column for MVP Nos. 5 and 7 that ITC Midwest is involved with. Likewise, please explain the decreased cost estimated in Q1 2015 compared to the MTEP Approved costs for MVPs Nos. 3 and 4. We recognize some of the cost responsibility belongs to partners of ITC Midwest, such as MidAmerican Energy, in developing these projects.

2. Referencing slide 17 of the May 13, 2015 Spring ITC Midwest Partners in Business Presentation found at http://www.oasis.oati.com/woa/docs/ITCM/ITCMdocs/2015_ITC_Midwest_Spring_Partners_in_Business_5.14.15_FINAL_for_OASIS_M....pdf, it was noted in the meeting discussion that the implementation of the NERC CIP-014-1 Physical Security standard may result in some changes to some ITC Midwest facilities in order to comply with the new standard. Please identify the anticipated cost and timing of those changes that presumably will be reflected in future ITC Midwest Attachment O rates. Please also note any changes to ITC Midwest facilities that may have peripheral impacts on associated IPL facilities, such as co-located substation assets. IPL will need to plan for any costs required for compliance of such facilities.

We appreciate your support of our continued efforts to better understand the components of the ITC Midwest formula rate, manage IPL's transmission expense and transmission costs for our customers, as well as ITC Midwest's desire to maintain open lines of communication and transparency with stakeholders.

Thank you,

John Weyer
Manager –Transmission Services
Alliant Energy Corporate Services, Inc.

Appendix 19 – July 21, 2015 ITC-M Response to IPL Information Request

RESPONSES OF ITC MIDWEST LLC, DATED JULY 21, 2015,
TO ALLIANT ENERGY'S FIRST SET OF INFORMATION REQUESTS, DATED JUNE 29, 2015

1-ITCMW--ALLIANT-1. Referencing the most recent MVP Dashboard of MVP Project Status as of April 2015 found at https://www.misoenergy.org/Library/Repository/Study/MTEP/MVP%20Portfolio%20Triennial%20Review/MVP%20Dashboard.pdf, please explain the increased cost under the column Cost, Q1 2015 compared to the MTEP Approved cost column for MVP Nos. 5 and 7 that ITC Midwest is involved with. We recognize some of the cost responsibility belongs to partners of ITC Midwest, such as MidAmerican Energy, in developing these projects. Likewise, please explain the decreased cost estimated in Q1 2015 compared to the MTEP Approved costs for MVPs Nos. 3 and 4.

RESPONSE:

ITC Midwest (ITCM) has not changed its cost estimates for its portions of MVP Nos. 3, 4, and 7 since the MTEP approval. Any changes in the costs shown for these projects are due to revised cost estimates submitted by other transmission owners for these jointly-owned projects.

ITCM is jointly developing the Cardinal-Hickory Creek portion of MVP 5 with ATC. The original cost estimates for MVP 5 were initially submitted to MISO by ATC alone. Most recently, ITCM and ATC worked together to develop the current cost estimate. ITC is not in possession of the supporting detail for the original cost estimate and, therefore, is not able to provide an exhaustive list of the factors that contributed to the increase in the cost estimate. However, ITC is aware of the following items which did contribute to the increase in the cost estimate: (1) higher costs associated with crossing the Mississippi River (including an upgrade to facilities), (2) costs associated with newly-identified upgrades to the Turkey River substation, and (3) the change in the project mid-line substation location from Spring Green to Montfort.

ITC is not a participant in the Badger-Coulee portion of MVP 5, which may also account for a portion of the increased costs shown for MVP 5.

**RESPONSES OF ITC MIDWEST LLC, DATED JULY 21, 2015,
TO ALLIANT ENERGY'S FIRST SET OF INFORMATION REQUESTS, DATED JUNE 29, 2015**

1-ITCMW--ALLIANT-2. Referencing slide 17 of the May 13, 2015 Spring ITC Midwest Partners in Business Presentation found at http://www.oasis.oati.com/woa/docs/ITCM/ITCMdocs/2015_ITC_Midwest_Spring_Partners_in_Business_5.14.15_FINAL_for_OASIS_M....pdf, it was noted in the meeting discussion that the implementation of the NERC CIP-014-1 Physical Security standard may result in some changes to some ITC Midwest facilities in order to comply with the new standard. Please identify the anticipated cost and timing of those changes that presumably will be reflected in future ITC Midwest Attachment O rates. Please also note any changes to ITC Midwest facilities that may have peripheral impacts on associated IPL facilities, such as co-located substation assets. IPL will need to plan for any costs required for compliance of such facilities.

RESPONSE:

ITC Midwest (ITCM) is currently in the process of performing assessments in accordance with the requirements of the CIP-014-1 Reliability Standard. Until those assessments are completed, ITCM is unable to estimate the costs of any projects associated with complying with the Reliability Standard for itself, Interstate Power and Light Company, or any other transmission customer at co-located facilities. While our 2016 projections may include some estimated costs associated with CIP-014-1 compliance, specific projects will not be developed until our assessments are complete.

Appendix 20 – October 9, 2015 IPL Information Exchange Request

ALLIANT ENERGY

Alliant Energy
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

1-800-ALLIANT (1-800-255-4268)
alliantenergy.com

October 9, 2015

RE: ITCM-Annual True-up, Information Exchange, and Challenge Procedures—Information Exchange

To: misoformularates@itctransco.com

Information Exchange Request

Alliant Energy – Interstate Power and Light Company (IPL) submits this Information Exchange request pursuant to Section III of the ITC Midwest LLC (ITCM) Attachment O Annual True-Up, Information Exchange, and Challenge Procedures published as part of the Midcontinent Independent System Operator, Inc. (MISO) Tariff. The following questions relate to discussion at the Fall 2015 ITCM Partners in Business meeting held in Cedar Rapids, IA on September 30, 2015, the presentation posted at ITCM's OASIS (http://www.oasis.oati.com/ITCM/) under item 108, and generally regarding costs impacting customers of ITCM and IPL.

1. Referencing the discussion of 2016 Attachment O - Projected Formula Rate:
    a. Now with the experience of first three quarters of 2015, how are ITCM capital expenditures for 2015 trending relative to the plan reflected in the 2015 Attachment O – ITCM Projected Formula Rate published and presented on a year ago?
    b. Likewise, how is the ITCM Rate Zone load trending in 2015 relative to the projections made for 2015 in the 2015 Attachment O – ITCM Projected Formula Rate published and presented on a year ago?
    c. How are these capital expenditure and load trends in 2015 thus far expected to impact the True-Up for 2015 to be applied in 2017 rates?

2. Krista Tanner, President of ITCM, commented verbally in her opening remarks that 2016 capital expenditures are expected to be approximately $90 million less than budgeted and originally projected in the last 5 year plan published in April of 2014. She indicated that approximately $60 million of that $90 million consists of deferred projects, and implied that the remaining largely consisted of a reduction in expected customer-driven projects.
    a. Is the approximately $90 million reduction in capital expenditures for 2016 already reflected as a reduction in rate base in the 2016 Attachment O - Projected Formula Rate published on August 29, 2015 and presented on at the September 30, 2015 meeting?
    b. If the answer to 2.a. is "no", how and when would we expect to see a reduction in 2015 rates reflected?

c. Will any of the approximately $90 million reduction in capital expenditures for 2016 impact any project capital placed in service yet in 2015?
d. If the answer to 2.c. is "yes", to what extent will that impact the 2015 rate and how and when would we expect to see that reflected in rates?

Thank you,

John Weyer
Manager –Transmission Services
Alliant Energy Corporate Services, Inc.
319-786-7112
johnweyer@alliantenergy.com

Appendix 21 – October 27, 2015 ITC-M Response to IPL

RESPONSES OF ITC MIDWEST LLC, DATED OCTOBER 27, 2015,
TO ALLIANT ENERGY'S THIRD SET OF INFORMATION REQUESTS, DATED OCTOBER 9, 2015

3-ITCMW--ALLIANT-1. Referencing the discussion of 2016 Attachment O – projected Formula rate:

a. Now with the experience of first three quarters of 2015, how are ITCM capital expenditures for 2015 trending relative to the plan reflected in the 2015 Attachment O- ITCM Projected Formula Rate published and presented on a year ago?

b. Likewise, how is the ITCM Rate Zone load trending in 2015 relative to the projections made for 2015 in the 2015 Attachment O – ITCM Projected Formula Rate published and presented on a year ago?

c. How are these capital expenditures and load trends in 2015 thus far expected to impact the true up for 2015 to be applied in 2017 rates?

RESPONSE:

a. In the current full-year forecast, which includes 9 months of actuals and 3 months of forecast, capital additions to plant in service are expected to be $310 million, which is less than the $363 million projected in 2015 ITCM formula rates.

b. The year-to-date, as well as the full-year forecast, load is tracking to the load projection used in the rate posting.

c. Lower than projected 2015 capital additions to plant in service are expected to lower the 2015 revenue requirement. Given that forecasted load is tracking projections, the load trends are not expected to have significant impact on the 2015 true up.

RESPONSES OF ITC MIDWEST LLC, DATED OCTOBER 27, 2015, TO ALLIANT ENERGY'S THIRD SET OF INFORMATION REQUESTS, DATED OCTOBER 9, 2015

3-ITCMW--ALLIANT-2. Krista Tanner, President of ITCM, commented verbally in her opening remarks that 2016 capital expenditures are expected to be approximately $90 million less than budgeted and originally projected in the last 5 year plan published in April of 2014. She indicated that approximately $60 million of that $90 million consists of deferred projects, and implied that the remaining largely consisted of a reduction in expected customer-driven projects.

a. Is the approximately $90 million reduction in capital expenditures for 2016 already reflected as a reduction in rate base in the 2016 Attachment O - Projected Formula Rate published on August 29, 2015 and presented on at the September 30, 2015 meeting?

b. If the answer to 2.a. is "no", how and when would we expect to see a reduction in 2015 rates reflected?

c. Will any of the approximately $90 million reduction in capital expenditures for 2016 impact any project capital placed in service yet in 2015?

d. If the answer to 2.c. is "yes", to what extent will that impact the 2015 rate and how and when would we expect to see that reflected in rates?

RESPONSE:

a. Yes. The 2016 rate projections posted in late August 2015 already incorporate the impacts of the planned reductions in 2016 capital spending that were discussed at the September 30, 2015 PIB meeting. In preparing this response, it was noted that the actual planned reduction in non-MVP capital spending is even greater than reported at the meeting: $105 million, not $90 million. Due to the timing of when a capital project goes into service, a reduction in 2016 capital spending may not be directly reflected "as a reduction in rate base" in 2016, as this question suggests.

b. Please see the response to question 2(a), above.

c. Yes, there were some capital additions originally scheduled for 2016 that were accelerated to 2015, but any resulting impact was offset by either cancellation or changes in timing for other projects such that overall 2015 capital spend did not increase.

**RESPONSES OF ITC MIDWEST LLC, DATED OCTOBER 27, 2015,
TO ALLIANT ENERGY'S THIRD SET OF INFORMATION REQUESTS, DATED OCTOBER 9, 2015**

d. These impacts, discussed in response to 2(c), above, were already included in the 2015 capital spend projections underlying development of the 2015 projected rates currently in effect. This 2015 projected capital spend projection reflected in current rates was $15 million less than reflected in the April 2014 five year plan.

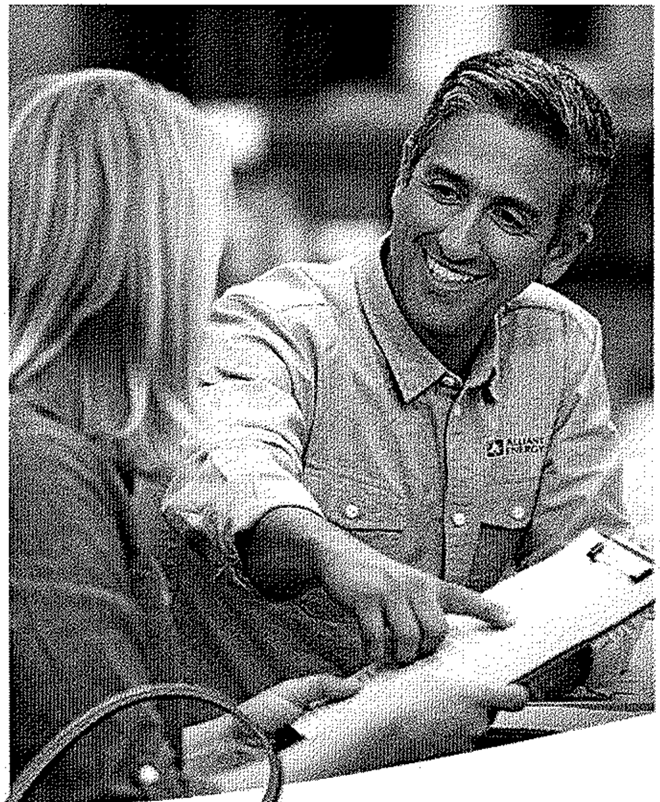
Appendix 22 – December 2, 2015 IPL Transmission Stakeholder Meeting Agenda and Presentation

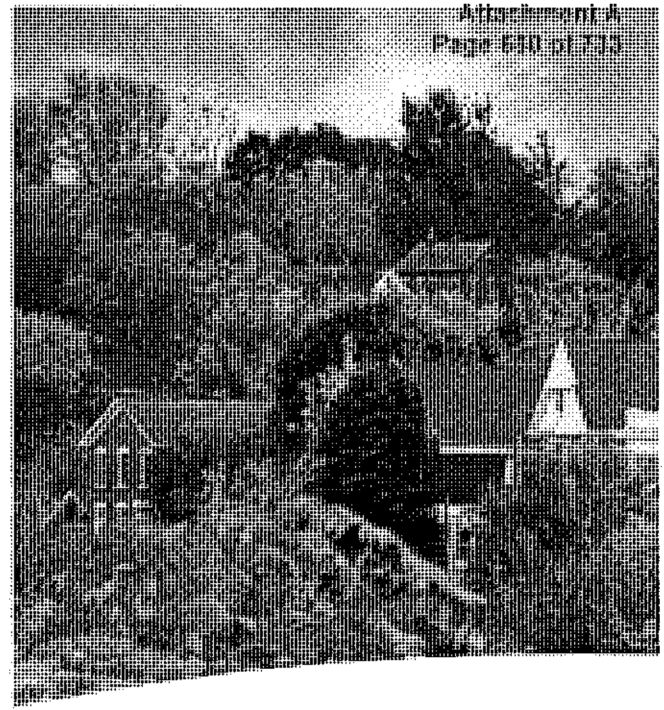
ALLIANT ENERGY
Interstate
Power and Light

Transmission Stakeholder Meeting Agenda

Wednesday, December 2, 2015
9:00 AM – 2:00 PM
The Hotel at Kirkwood Center
Cedar Rapids, IA

Time	Topic	Presenters
9:00	Welcome, Introductions & Opening Remarks	John Weyer, Manager – Transmission Services, Alliant Energy Joel Schmidt, VP - Regulatory Affairs, Alliant Energy
9:20	ITC Midwest Remarks	Krista Tanner, President – ITC Midwest
9:40	Planning, Projects and Engineering Update	Chris Alva, Team Lead – Transmission Planning, Alliant Energy
10:00	Transmission Policy & Regulatory Update	Eric Guelker, Director – Transmission Policy and Sales Forecasting, Alliant Energy
10:25	Energy Price Outlook	Jason Nielsen, Manager – Regulatory Affairs, Alliant Energy
10:40	Break	
11:00	Open Panel Q&A, Collaboration w/ IPL	Panel: Joel Schmidt, Eric Guelker, John Weyer Moderator: Anne Lenzen
12:00	Lunch	
1:00	Transmission Reliability Update	John Weyer
1:10	ITC Midwest Rate Update	John Weyer
1:30	Adjourn	





Welcome

Alliant Energy – Interstate Power & Light Co.
Transmission Stakeholder Meeting

The Kirkwood Center – Cedar Rapids, IA
December 2, 2015

ALLIANT ENERGY

Welcome & Introductions

John Weyer

Manager - Transmission Services

Alliant Energy

Today's Agenda

- Opening
- ITC Midwest Remarks
- Planning, Projects and Engineering Update
- Transmission Policy & Regulatory Update
- Energy Price Outlook
- Break
- Open Q&A Panel, Collaboration w/ IPL
- Lunch
- Transmission Reliability Update
- ITC Midwest Rate Update

ALLIANT ENERGY.

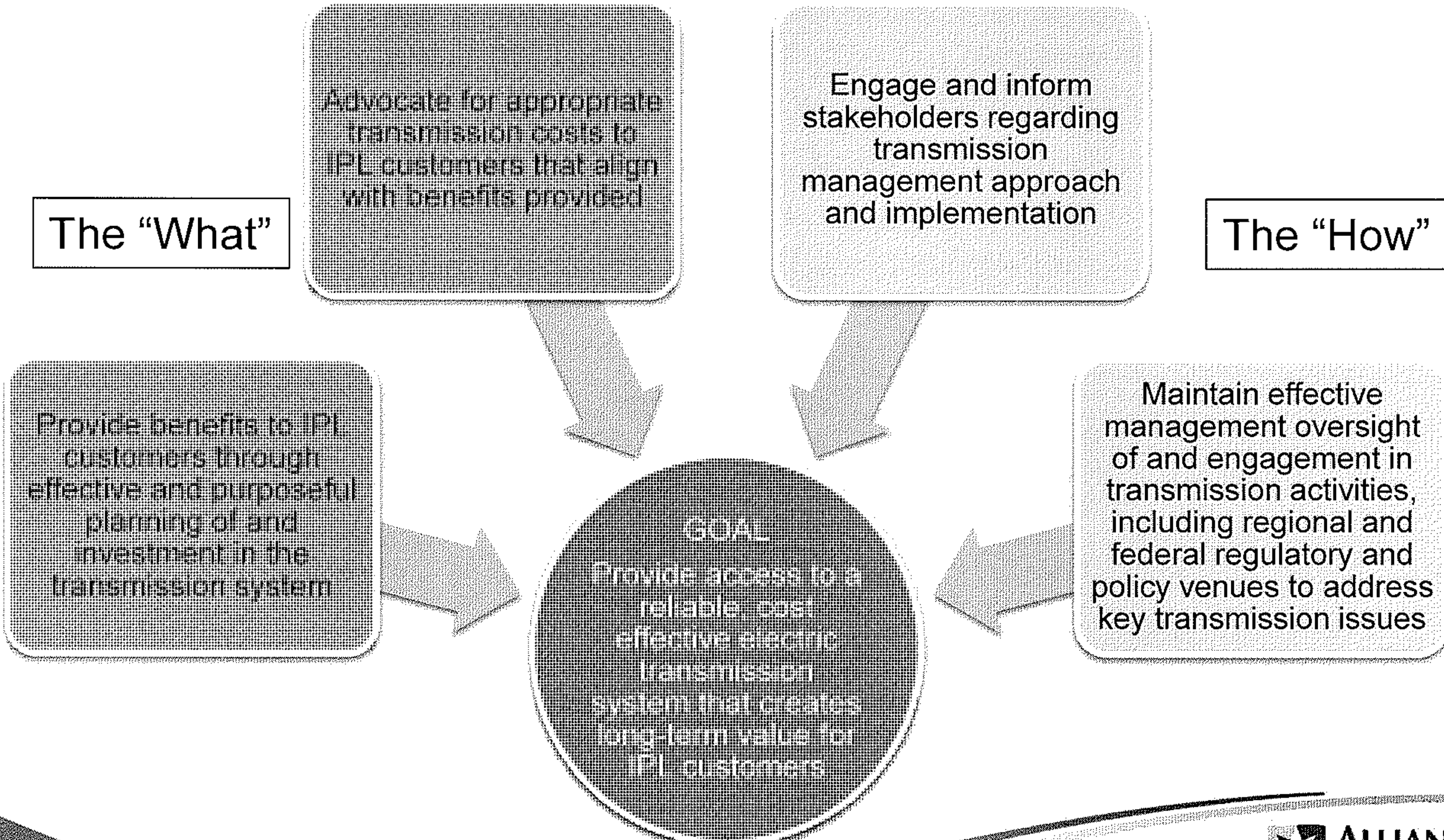
Opening Remarks

Joel Schmidt

Vice President - Regulatory Affairs

Alliant Energy

Transmission
IPL Management Approach



ALLIANT ENERGY

Questions?

ITC Midwest Remarks

Krista Tanner

President

ITC Midwest

Planning, Projects and Engineering Update

Christian Alva

Team Lead, Transmission Planning,

Alliant Energy

Objectives

- Discuss Areas within IPL Planning, Projects and Engineering areas that impact Transmission

- Demonstrate several examples of what we are doing to create "value"

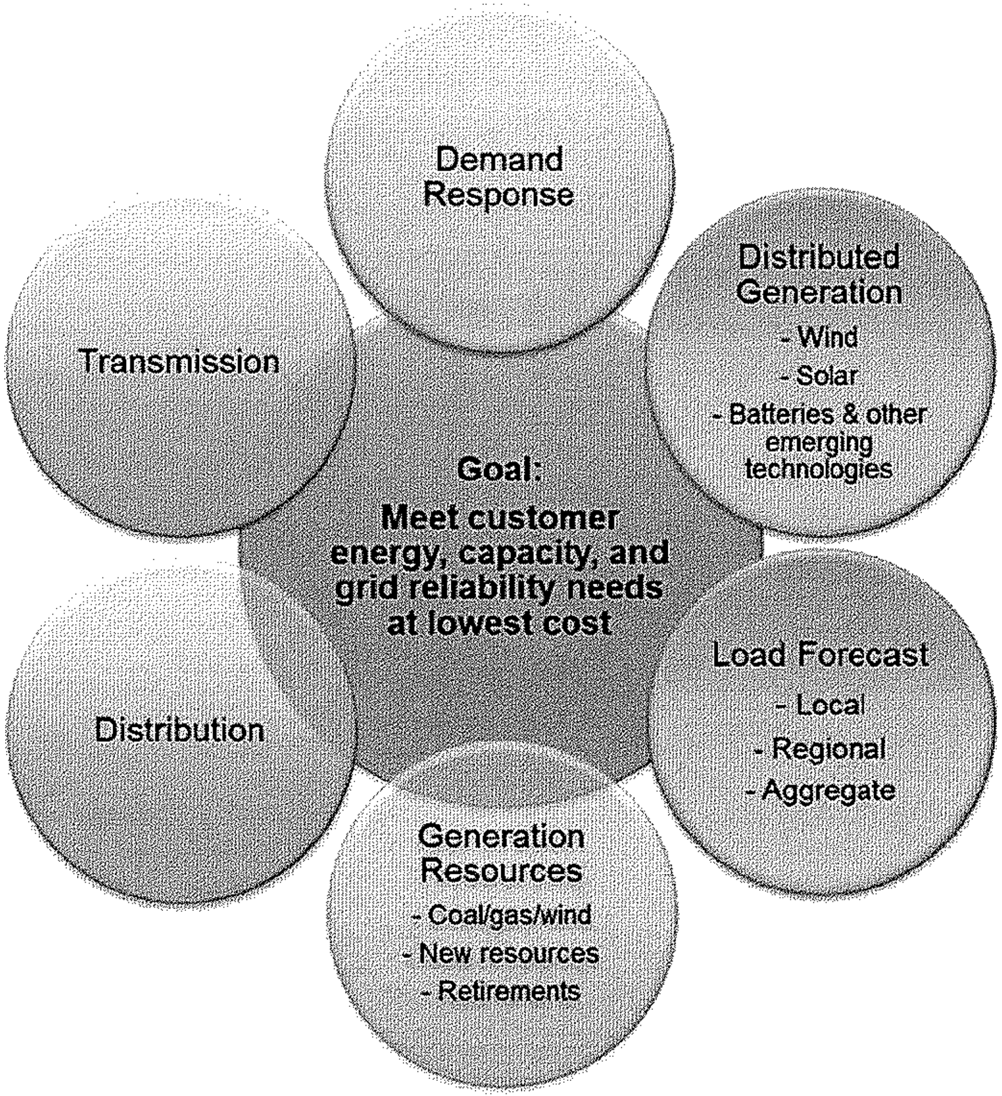
Where do we "touch" transmission

- MISO Committees
  - Planning Advisory Committee (PAC)
  - Planning Subcommittee (PSC)
  - Interconnection Process Task Force (IPTF)
  - Regional Expansion Criteria & Benefits Task Force (RECBTF)
  - Interregional Planning Stakeholder Advisory Committee (IPSAC)
  - MISO Transmission Expansion Planning (MTEP)
- Generation: New (Att. X) and Retirements (Att. Y)
- Transmission Outage Planning (Daily)
- Project Planning with IPL Distribution Engineering
- Joint Planning Meetings with ITC and CIPCO
- Joint Project Meetings with ITC
- Regular Executive Meetings with ITC

Each of these is an area of influence

ALLIANT ENERGY

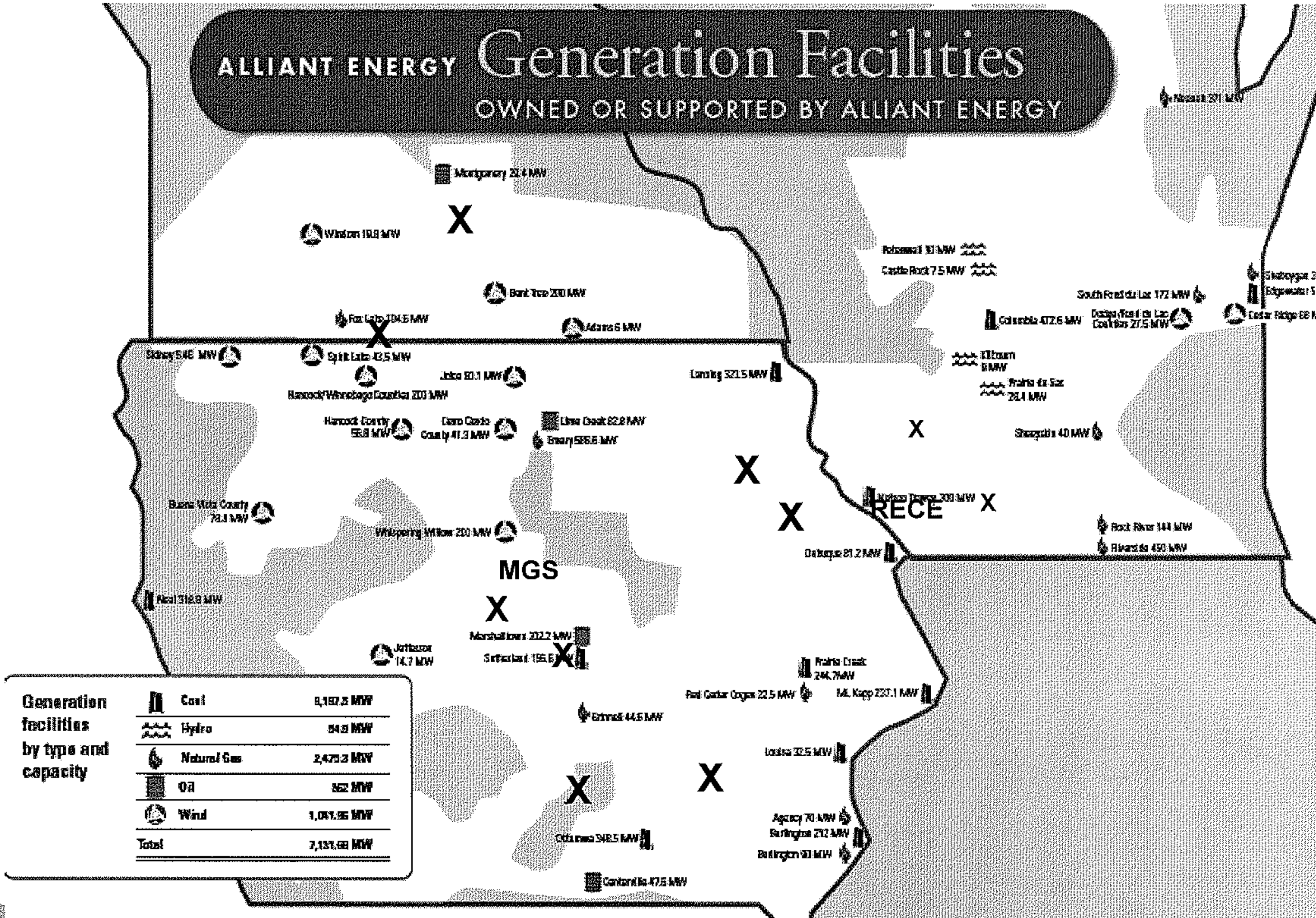
Example 1: Holistic System Planning



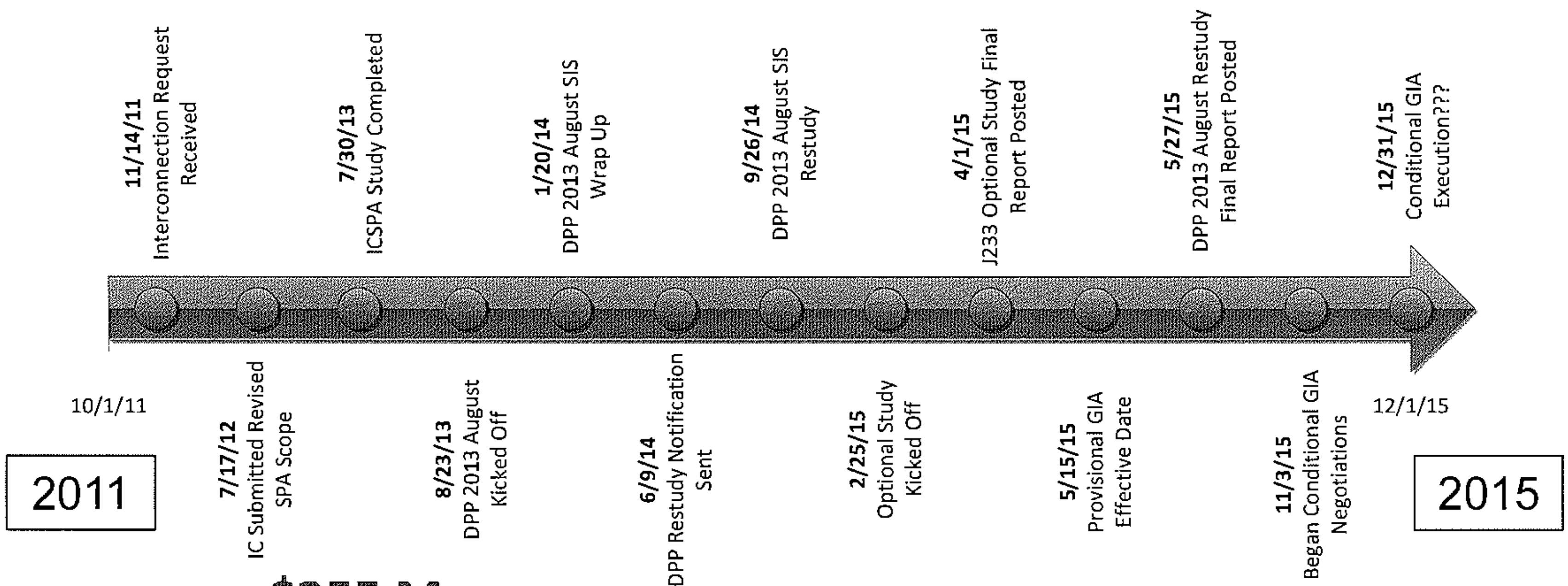
- Always the Big Picture
- Gas and electric
- Local affects global
- Toolbox with multiple options

ALLIANT ENERGY

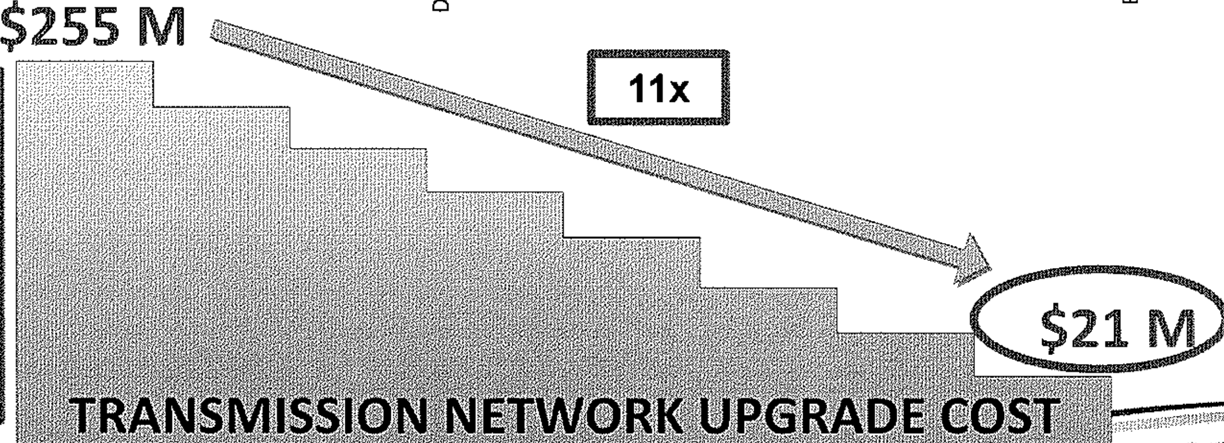
Our generation assets will look different ten years from now



Example 2: Marshalltown Generation



Significant $ decrease of Transmission Upgrades in part resulting from IPL's direct and substantial involvement in process



ALLIANT ENERGY

Example 3: Planning Meetings

- Bi-monthly and quarterly meetings with Transmission Owners to discuss capital projects

- Daily interactions to discuss planned outages and coordination
  - ITC-M EOR's Reviewed
    - October 2015: 125
    - YTD: 1498

- Topics of Discussion
  - Review of capital projects to be done and when
  - Cross-company impacts and coordination

Key Takeaways

- Even as a transmission dependent utility, IPL continues to be actively engage on managing and monitoring an array of transmission activities
- IPL Planning, Projects and Engineering groups participate in multiple venues to create value for IPL customers

ALLIANT ENERGY

Questions?

Transmission Policy & Regulatory Update

Eric Guelker
Director – Transmission Policy and Sales Forecasting
Alliant Energy

Transmission Policy

Federal Energy Regulatory Commission (FERC)

Primary regulatory agency that *develops and oversees* transmission policy

Midcontinent Independent System Operator (MISO)

Primary transmission provider and organization (for IPL) that *implements* transmission policy

ITC Midwest

Primary transmission owner in IPL service territory that works in conjunction with IPL and MISO to implement transmission policy

Key Aspects of Transmission Policy
Federal & state energy policy objectives
Regional transmission planning & projects
Transmission infrastructure development & modernization
Transmission costs & cost allocation

IPL has and will continue to engage in transmission policy to advocate for IPL customers with ITC Midwest, MISO and FERC.

ALLIANT ENERGY

Transmission Policy Key Issues

- ITC Bonus Depreciation Opt Out
  - Opportunities to Get Involved
- Transmission Return on Equity (ROE)
  - MISO ROE Complaints
  - Potential Changes to ROE – ***Refunds coming!***
- ITCM Attachment FF
- Retail Customer Ability to Challenge FERC Rates

ALLIANT ENERGY

ITC Bonus Depreciation Opt Out

Background

- In effect since 2008
- Allows first year 50 or 100% deduction of capital invested
- Expect Congress to extend through 2015
- Prevailing utility industry practice to use

Issue

- ITC proactively opted out of using since 2009
- Increases ITCM customer costs -- 2015 ITCM transmission rate about 5% higher
- Impacts many ITC transmission assets including WPL Bent Tree Wind Farm upgrades

Action

- IPL has worked with ITC since June to resolve but reached an impasse
- WPL protest and IPL comments filed in WPL Bent Tree Wind Farm FERC proceeding
- IPL currently preparing Formal Challenge to file at FERC – plan to file in December

Bonus depreciation opt out impacts all ITC Holdings transmission company capital investments within an IRS asset class. Opt out increases costs for all transmission and many interconnection customers.

ALLIANT ENERGY.

ITC Bonus Depreciation Opt Out

Opportunities to Get Involved

WPL Bent Tree Wind Farm Facility Services Agreement (FSA) FERC Proceeding (ER16-206)

Background
- Opt out increases transmission upgrade costs by about $12 million
- In FSA, ITC refused to commit to using bonus depreciation if eligible
- FSA filed at FERC unexecuted

WPL & IPL Action
WPL Protest and IPL Comments filed

Stakeholder Action
- LEG provided letter of support
- ICC, OCA and IUB provided supportive comments

IPL Formal Challenge FERC Proceeding (ER15-1250)

Background
- Final step in MISO formula rate protocols
- Challenge prudence of ITC decision to opt out
- Opt out increases customer cost without offsetting customer benefit

IPL Action
Plan to file challenge in December – specific date TBD

Stakeholder Action
TBD

Thank you to stakeholders for your support to-date on this issue. Please consider supporting IPL's upcoming formal challenge.

ALLIANT ENERGY.

Transmission Return on Equity (ROE)

- Scrutiny of ROEs has increased
  - Interveners believe ROEs should reflect "new normal" of lower interest rates and costs of capital
- Numerous complaints are pending at FERC and ROEs recently accepted by FERC are lower
- In June 2014 in response to ISO-New England ROE complaint, FERC issued Opinion No. 531.

Opinion No. 531 Key Findings

Adopts the two-step DCF methodology for electric utility ROEs, also used to determine natural gas and oil pipeline ROEs	Places the ROE halfway between the midpoint and the top of the "zone of reasonableness"	Indicates total ROE (including incentives or adders) cannot exceed the top of the "zone of reasonableness"

ALLIANT ENERGY

MISO ROE Complaints

Original Complaint (EL14-12) November 2013

- Reduce ROE from 12.38% to 9.15%
- Limit equity contributed to capital to no more than 50% for ratemaking purposes
- Eliminate incentive RTO and independence adders

FERC Initial Decision October 2014

- Established ROE refund date of November 12, 2013
- Denied complaints requesting 50% equity contribution limit and eliminating incentive adders

Original Complaint Current Status

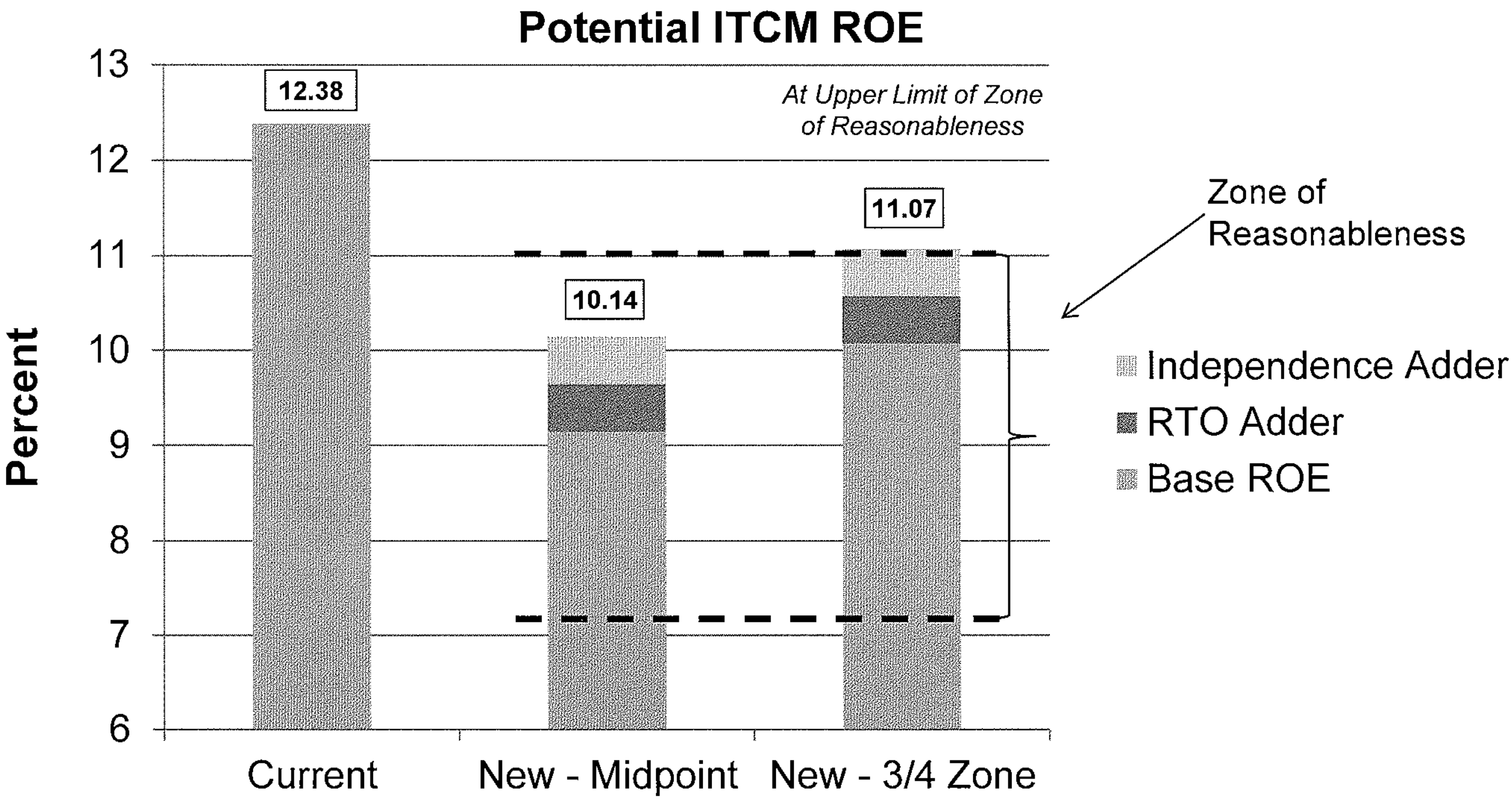
- Hearings, briefings and oral arguments completed
- FERC ALJ decision expected December 15, 2015; final order by FERC expected in 2H 2016
- 15 month refund period: November 2013 – February 2015

Second ROE Complaint (EL15-45) February 2015

- FERC set for hearing; testimony filed
- FERC ALJ decision expected June 2016; final order by FERC expected in Q2 2017
- 15 month refund period: February 2015 - May 2016

Potential Changes to ROE

Based upon Updated FERC Staff Testimony (EL14-12)



Each 1 percentage point (100 bps) change in ROE changes ITCM rate by about 5-6%

ALLIANT ENERGY.

ITC Midwest Attachment FF

- Attachment FF change requires generators (instead of transmission customers) to pay new generation–related transmission network upgrade costs
- ITCM is self-funding upgrades and collecting upgrade costs from generators levelized over term of interconnection agreement
  - ITCM transmission customers held harmless on a present worth basis
  - IPL and WPL are funding upgrades for IPL's Marshalltown Generating Station and WPL's Bent Tree wind farm using this option
- Pending FERC proceeding (EL15-68) may change current unilateral right of transmission owners to self-fund upgrades
  - IPL and WPL filed comments supporting approach that considers customer costs when determining who provides initial upgrade funding

Projected annual revenue from generators, which offsets ITCM transmission customer costs, increased from about $1.2M in 2015 to $5.9M in 2016

ALLIANT ENERGY

ITC Midwest Attachment FF (EL12-104)

September 2012: IPL filed complaint against ITCM	• Requested Attachment FF change to ***require generators to pay transmission network upgrade costs*** • Existing approach different & more costly to IPL customers
October 2012: Stakeholders filed comments	• Many stakeholders including OCA, ICC, MPUC and MDOC supported IPL's complaint
July 2013: FERC issued order granting IPL's complaint	• Ruled change would apply to generator interconnection agreements (GIAs) executed or filed after date of order • GIA amendments to be addressed on case-by-case basis
August 2013: IPL and ITCM file rehearing/clarification requests	• IPL and ITCM requested FERC clarify transition from "old" to "new" approach; don't address case-by-case • ITCM also requested FERC to reconsider its decision
September 2013: FERC granted IPL and ITCM rehearing requests	• FERC needs more time to review -- doesn't imply FERC will or will not change its decision • Attachment FF changes per July order are effective
February 2014: FERC denied rehearing and granted and denied in part clarification requests	• Ruled future amendments to GIAs that are provisional as of date of July order will use "new" approach • Amendments to other GIAs to be addressed on case-by-case basis
March 2014: NextEra filed rehearing request	• Argues that provisional GIAs not amended prior to July order because of delays by MISO should use "old" approach
April 2014: FERC granted NextEra rehearing request	• FERC needs more time to review -- doesn't imply FERC will or will not change its decision
November 2015: FERC denied NextEra rehearing request	• FERC agrees that approach in place at time a provisional GIA is amended shall be used

This FERC proceeding is likely finished

ALLIANT ENERGY.

Retail Customer Ability to Challenge FERC Rates (ER07-1069)

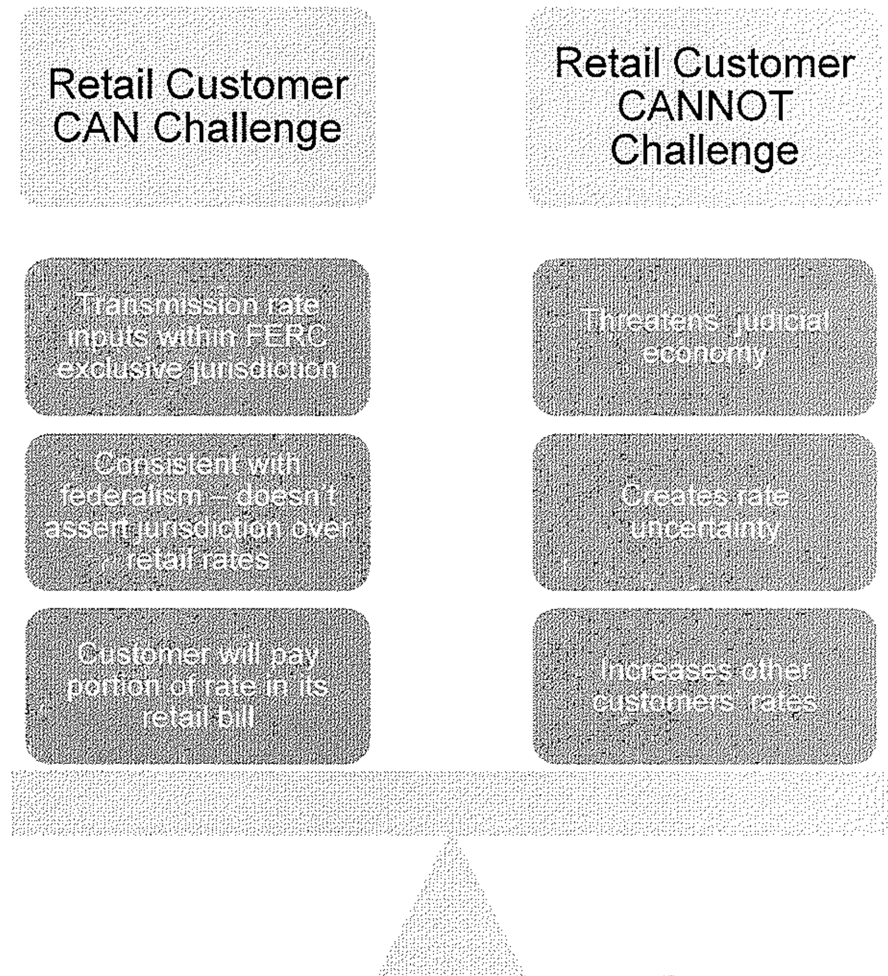
Retail customer filed challenge to SWEPCO/AEP transmission formula rate

FERC settlement judge solicited input on whether or not retail customer can challenge rate from FERC trial staff, retail customer and SWEPCO/AEP

Settlement judge recommended CANNOT challenge

FERC overruled settlement judge concluding retail customers CAN challenge wholesale and transmission rates

Input to FERC Settlement Judge



ALLIANT ENERGY.

Summary

- Successful outcome on bonus depreciation opt out will likely significantly reduce annual ITCM rate. Your support is appreciated and can make a difference.
- Transmission ROE will very likely decrease.
  - **ITCM total ROE decrease of 1 to 2% is plausible**
  - **Refunds anticipated as early as 2017**
- Changes to ITCM's Attachment FF generator interconnection cost allocation policy are and will continue to result in positive IPL customer benefits.
- IPL customers have the ability and opportunity to directly challenge ITCM rates and costs at FERC; however, IPL plans to continue working collaboratively with customers and stakeholders on future challenges.

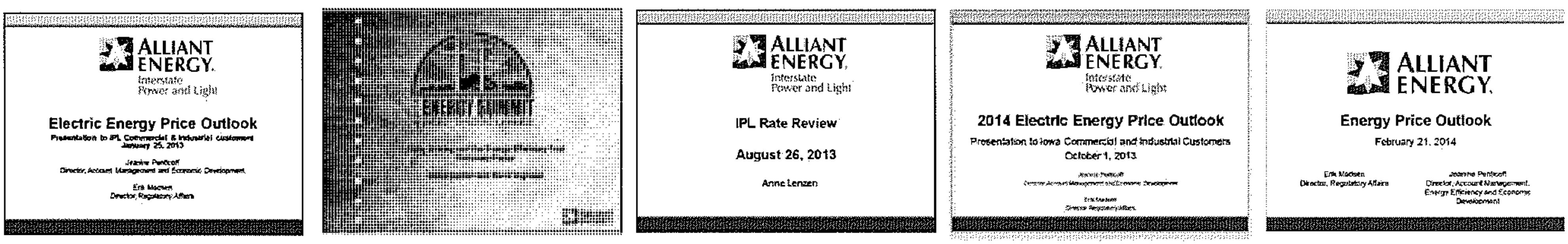
Questions?

Energy Price Outlook

Jason Nielsen
Manager – Regulatory Affairs
Alliant Energy – IPL

Keeping you informed

- Ongoing pricing outlook webinars since 2011
- Last webinar in October 2015
- Energy Summit May 3, 2016



Tell us what information would be helpful to you.

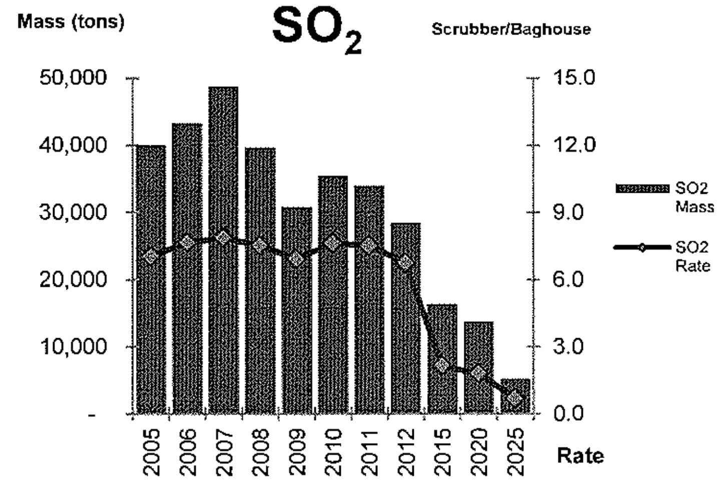
ALLIANT ENERGY.

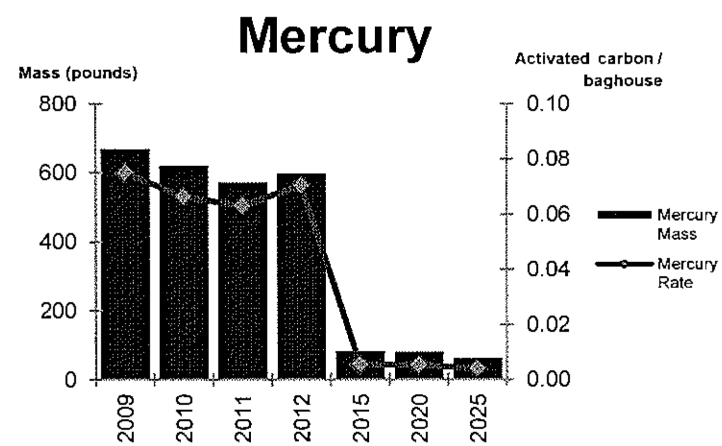
Agenda

- Service improvements and customer benefits
- Budgeting guidelines through 2018
- 2017 rate case
- Solutions for your business

Service improvements and customer benefits

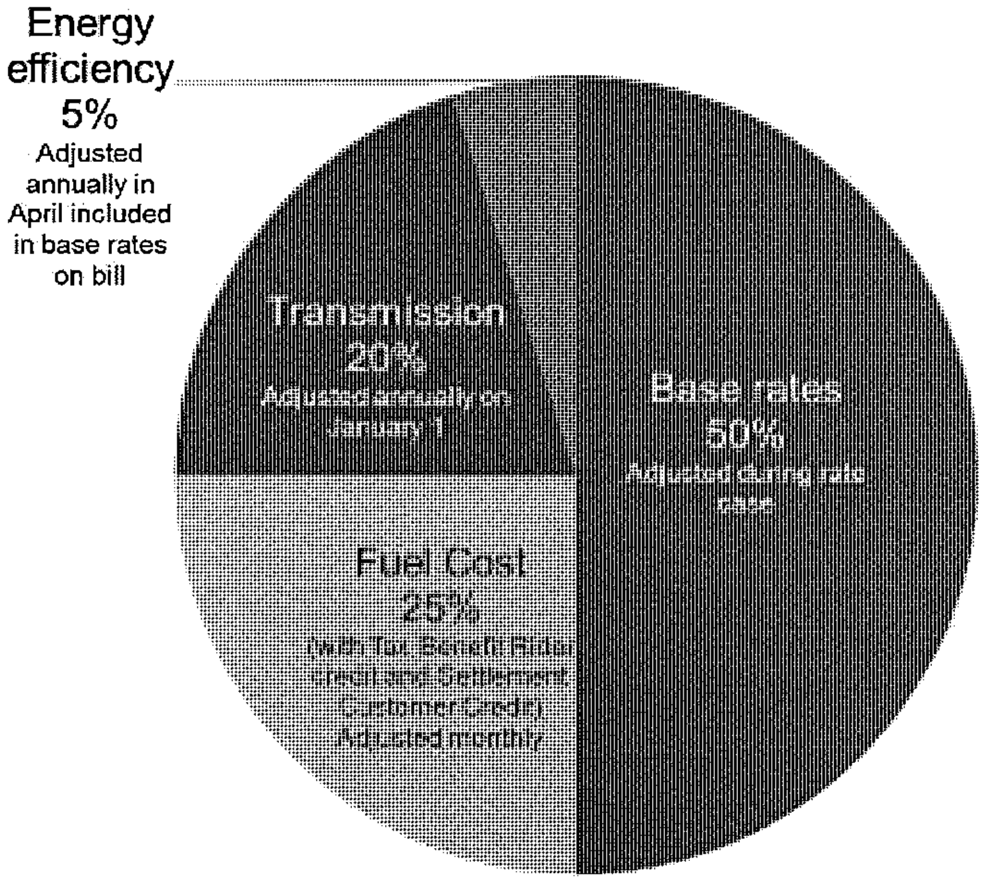
- We are making air cleaner in Iowa
  - From 2011 to 2016, we expect to reduce mercury by 84% and sulfur dioxide by 72%
- We are making the electric grid stronger
  - You have fewer and shorter outages
    - Since 2010, approximately 20% fewer outages and we've shortened the time customers experience an outage by approximately 30%
- New customer information and billing system
- Tax Benefit Rider
  - Customer savings in excess of $400M
- Lower cost nuclear purchased power agreement





ALLIANT ENERGY

Bill breakdown



**Represents typical Large General Service bill breakdown.*

Budgeting Guidelines vs. Prior Year

Bill Component	Frequency of Change	2015 Bill Impact	2016 Bill Impact	2017 Bill Impact	2018 Bill Impact
Base Rates	Rate Case	No change	No change	5%	4%
Fuel Cost	Monthly Adjustment	-2%	3%	-1%	0%
Transmission	Annual Adjustment	1%	2%	2%	2%
Tax Benefit Rider	Annual Adjustment	1%	1%	4%	-5%
Customer Credit	Annual Adjustment	3%	1%	0%	0%
Energy Efficiency	Annual Adjustment	No change	No change	No change	No change
Total Bill		3%	7%*	10%*	1%*

*Estimation Range = +/-2% for 2016, +/-3% for 2017 and 2018

ALLIANT ENERGY.

Transmission Rate

- Transmission aka Regional Transmission Service (RTS)
- New factor proposed January 1, 2016

RTS Factors	2015	2016 (proposed)
General Service	$0.02579 / kWh	$0.02837 / kWh
Large General Service	$7.40 / kW	$7.99 / kW

2015							2016
Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan

- Jun: ITC-Midwest reconciles 2014 costs
- Sep: ITC-Midwest projects 2016 costs
- Oct: Alliant Energy reconciles 2016 transmission factor balance
- Nov: RTS Factors filed with IUB for approval
- Jan: RTS Factors in effect

ALLIANT ENERGY.

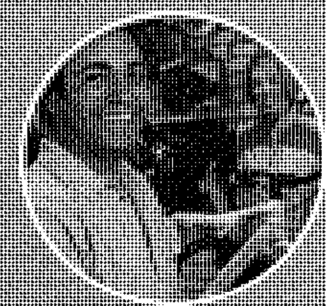
Rate case 2017

- Base rate freeze through 2016
- Timing of filing: April 2017 (estimated)
  - Interim rates effective mid- to late-April 2017
  - Final rates effective in 1Q 2018
- Includes
  - Marshalltown Generating Station
    - 600 MW natural gas plant
    - Approved by IUB/Ratemaking principles
  - Environmental controls / distribution system upgrades
  - New customer information and billing system (2016)
- Identified mitigation measures
  - Lean cost controls
  - Lower costs for MGS transmission interconnection
  - Tax Benefit Rider 2

ALLIANT ENERGY.

Solutions for your business

- Energy-saving programs
- Resources
- Sustainability goals
- Energy partner for exploring options



Business Programs

Business energy assessments

Equipment rebates

Custom Rebates

Commercial New Construction

Industrial New Construction

Interruptible

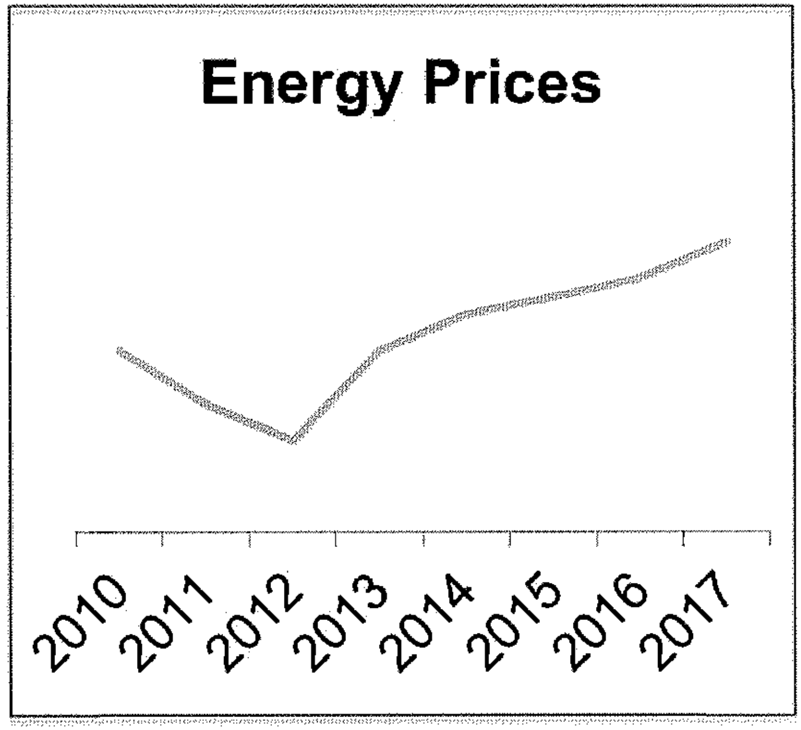
ALLIANT ENERGY

Who to contact at Alliant Energy?

- Your key account manager
- Business Resource Center
  - 1-866-ALLIANT (866-255-4268), option 2, option 2
    - 8 a.m. to 5 p.m. CST Monday through Friday
  - Email: *businesscenter@alliantenergy.com*
  - Web: *alliantenergy.com/business*
- Link to price schedules at *alliantenergy.com/tariffs*

Summary

- Prices are based on costs – driven by service improvements and environmental requirements
- Base rate freeze through 2016
- Budgeting guidelines through 2018
  - Continuing work to mitigate increases
- Energy Summit May 3, 2016



ALLIANT ENERGY.

Questions?

Break

Open Panel Q&A, Collaboration

<u>Panel</u>

Joel Schmidt

Eric Guelker

John Weyer

<u>Moderator</u>

Anne Lenzen

Director – Regulatory Affairs

Alliant Energy – IPL

ALLIANT ENERGY

Lunch

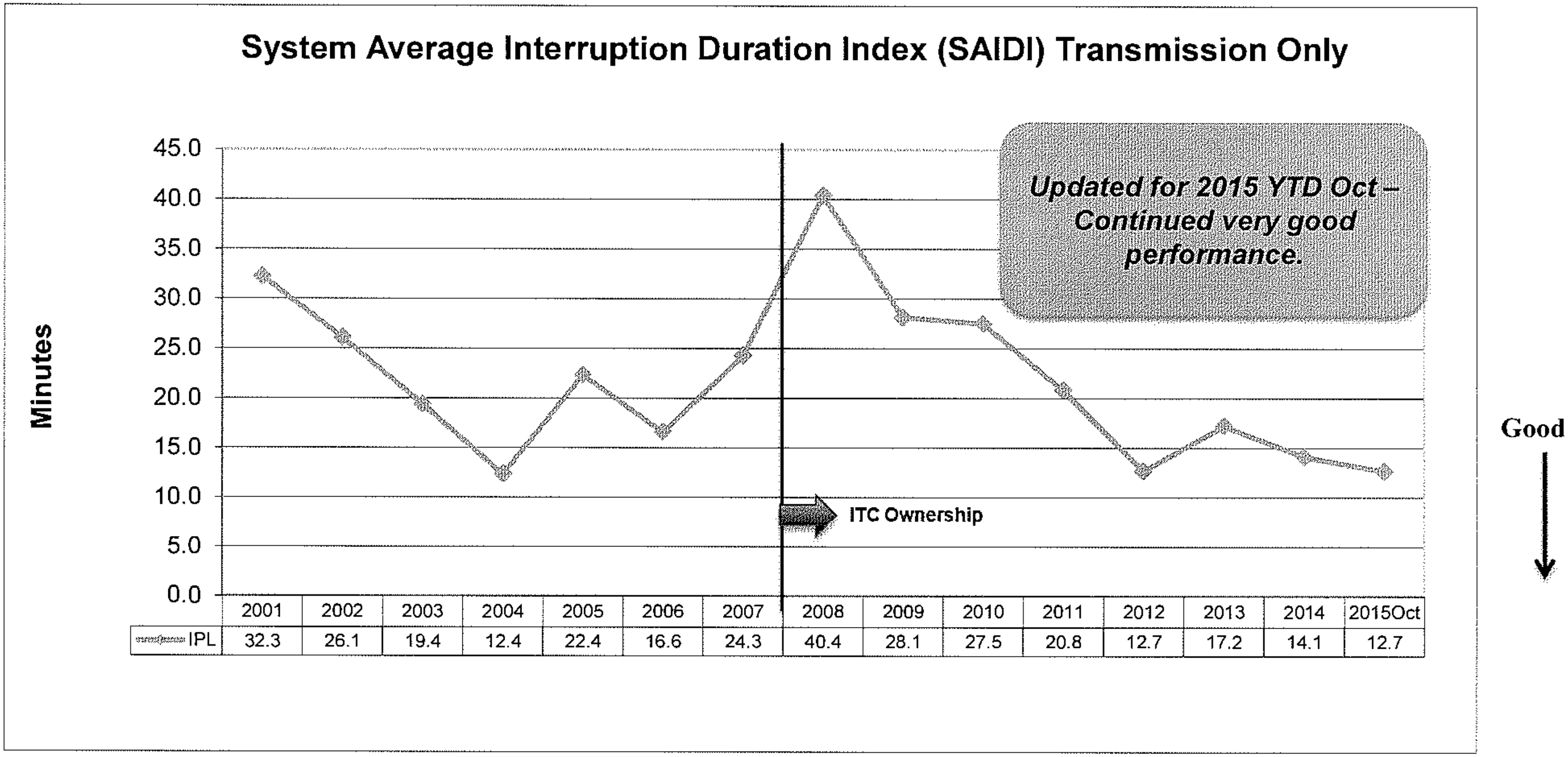
Transmission Reliability Update

John Weyer

Manager - Transmission Services

Alliant Energy

Transmission Benefits – Reliability



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015Oct
IPL	32.3	26.1	19.4	12.4	22.4	16.6	24.3	40.4	28.1	27.5	20.8	12.7	17.2	14.1	12.7

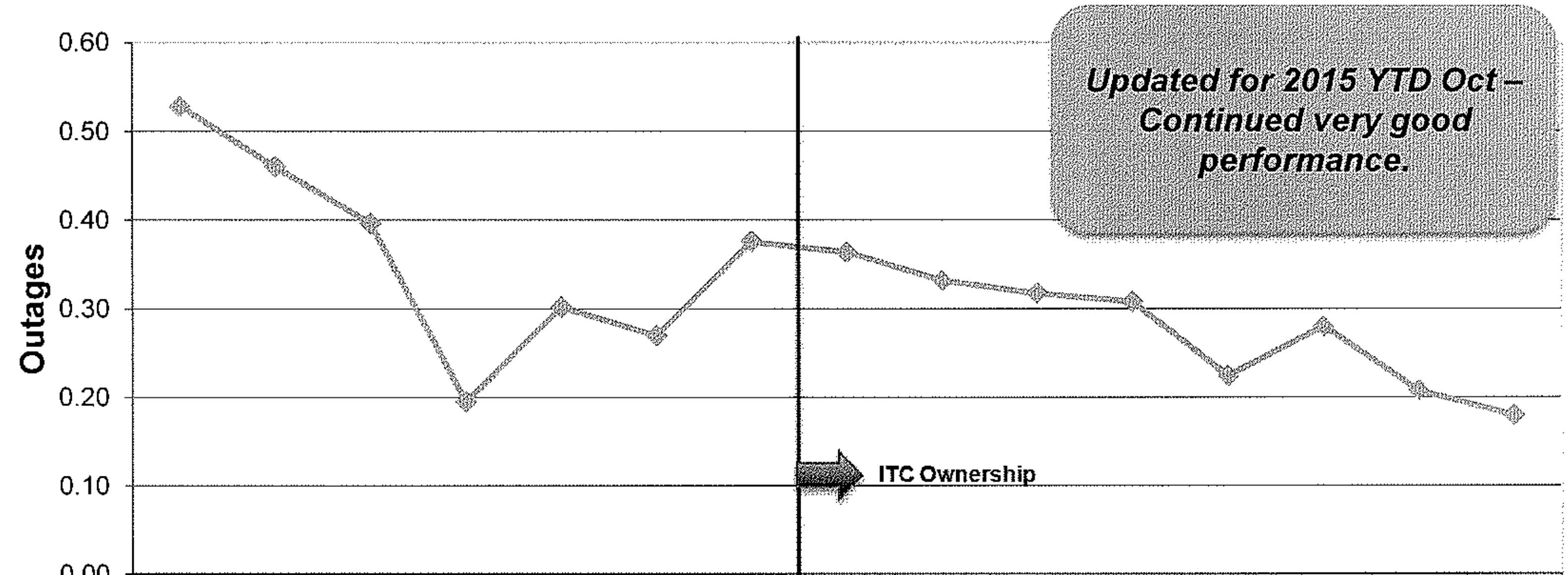
From prior analysis work, estimated outage cost savings to customers in the range of $168-498 million, in 2013 $ over the life of the assets, from the first few years of ITC-M ownership and operation

Average length in minutes of outages for all customers.

ALLIANT ENERGY

Transmission Benefits – Reliability

System Average Interruption Frequency Index (SAIFI) Transmission Only



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015Oct
IPL	0.53	0.46	0.40	0.19	0.30	0.27	0.38	0.36	0.33	0.32	0.31	0.22	0.28	0.21	0.18

Good

Significantly improved transmission reliability, with transmission investments helping reduce the frequency of transmission outages by approximately 30% since 2010

Average number of outages experienced by all customers.

ALLIANT ENERGY.

Questions?

ITC Midwest Attachment O True-Up

John Weyer
Manager - Transmission Services
Alliant Energy

ALLIANT ENERGY

2016 ITC Midwest Attachment O Rates

- ITCM posted the 2014 True-Up on May 29, 2015
  - $4.4 million refund applied to 2016 Attachment O rates
  - This results from an over collection of Attachment O rates in 2014 and includes interest.
  - Refund due mainly to higher offsets/credits and load than anticipated.
- 2016 Attachment O rates were posted on August 29, 2015
  - 9.798/kW-Mo for 2016, up $0.53 from $9.265/kW-Mo for 2015, or 5.7%
  - Increase due to more invested capital and additional operating expenses.
- IPL asked questions through the MISO Formula Rate Protocols after each posting.
- More details about ITCM rates, IPL questions and ITCM responses can be found on ITCM's OASIS page at http://www.oasis.oati.com/ITCM/

Questions?

Upcoming Transmission Activities

- **December** - RTS Factors filed with IUB for approval.
- **December 15** – Initial Decision due from FERC ALJ on first MISO ROE complaint
- **December 31** - IPL Semiannual Transmission Report due to Iowa Utilities Board (IUB).
- **January 2016** – 2016 Regional Transmission Service (RTS) Factors anticipated to be approved and in effect.
- **Late May or Early June** – IPL Transmission Stakeholder meeting.
- **June 1 –** ITCM 2015 True-Up posted.
- **June 30** - IPL Semiannual Transmission Report due to IUB.

ALLIANT ENERGY.

Summary

Alliant Energy has developed, implemented and continues to implement a strategy that incorporates active engagement with ITC Midwest, regional and federal policy to ensure that transmission investments provide value to Alliant Energy customers. As a result, our customers experience increased system reliability, resiliency and increased market access.

Who to contact at Alliant Energy?

- **Your Key Account Manager**

  "One Call Does All" – IPL continues to be the main point of contact for our customers for all issues, including transmission service.

- **Or**

Eric Guelker
Director - Transmission Policy and Sales Forecasting
Alliant Energy
608-458-8163
ericguelker@alliantenergy.com

Presentation and survey link will be sent to attendees.

Thank you and please travel safely!

ALLIANT ENERGY.