UNITED STATES OF AMERICA 116 FERC ¶63,030
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc.	Docket Nos. ER05-6-001, -002, -003, -005, -007, -008, -009, -013, -014, -016, -017, -018, -019, -020, -021, -022, -024, -026, -029, -031, -034
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC, *et al.*	Docket Nos. EL04-135-003, -004, -005, -007, -009, -010, 011, -015, -016, -018, -019, -020, -021, -022, -023, -026, -028, -031, -033, -036
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC, *et al.*	Docket Nos. EL02-111-020, -021, -022, -024, -026, -027, -028, -031, -033, -034, -036, -037, -038, -039, -040, -041, -042, -044, -046, -049, -051, -054
Ameren Services Company, *et al.*	Docket Nos. EL03-212-017, -018, -019, -021, -023, -024, -025, -029, -032, -033, -034, -035, -036, -037, -038, -040, -042, -045, -047, -050

INITIAL DECISION

(Issued August 10, 2006)

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20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

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20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

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20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

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20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

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CARMEN ANA CINTRON, Presiding Administrative Law Judge

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

TABLE OF CONTENTS

I. INTRODUCTION 8

II. PROCEDURAL HISTORY 8

III. ISSUES 16

Issue 1: Test Period – Volumes 16
A. With respect to the filers' use of 2002 calendar year as the test period for the first four months of the transition period (December 2004 – March 2005): 16
1. Should adjustments be made to the entire 2002 calendar year or only the corresponding 4 months? 16
2. What adjustments/changes/modifications are appropriate for determining SECAs? 16
B. With respect to the filers' use of 2003 calendar year as the test period for the twelve months of the transition period (April 2005 – March 2006): 16
1. What adjustments to the 2003 calendar year are appropriate? 16
2. What adjustments/changes/modifications are appropriate to determine SECAs? 16
C: Is the Analysis of the OATi tag data to identify, and to allocate a SECA responsibility to, importing zones or sub-zones adequately supported? 28
D: Are MWs for grandfathered contracts and duplicate tags properly removed? ... 28

Issue 2. Lost Revenues -- General 28
A. What are the through and out lost revenues of each Transmission Owner? 28
C. Should there be any adjustments to the lost revenues? What should those adjustments be? 29
Issue 2. Lost Revenues – Affiliate Issues 51
B. Should test period lost revenues include revenues for non-firm transmission service that are distributed by PJM under Section 27A of the PJM open-access tariff to firm transmission customers? 66

Issue 3: Rate Design 67
A. Basic Structure – Allocation and Rate Design: 67
1. Do the proposed SECA rate designs comply with the Commission's orders and are the resulting lost revenue allocations just and reasonable? 67
2. Are there known and measurable changes that should be reflected in developing SECA charges? 67
3. Are the proposed revision to each RTO's tariff just and reasonable? 67
B. Existing Transactions & Relationship to the SECA 80
2. Is the proposed process for crediting revenues from Existing Transactions reasonable? 81

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Issue 3.B.3: Whether the Boroughs of Lansdale, Blakely, Catawissa, Duncannon, Hatfield, Kutztown, Lehighton, Middletown, Mifflinburg, Olyphant, Quakertown, Royalton, St. Clair, Schuylkill Haven, Watsontown and Weatherly, Pennsylvania should be excluded from SECA charges due to firm power requirements contracts that existed during the test years but made no explicit statement regarding the location of the generation that supplied power under those contracts? 88
Issue 3.B.4: Should the PJM RTOR rate for transactions exiting PJM via the ComEd zone be credited to an effective rate of $1.00/kW and, if not, what should the rate be? 89
C. and 3.C. combined (OATi Tag Data and Zones/Sub-zones) 89
A. Issue 1.C. Is the analysis of OATI tag data to identify, and to allocate a SECA responsibility to, importing zones or sub-zones adequately supported? 89
B. Issue 3.C. Zone/Sub-zone: 89
1. Are the proposed zones and sub-zones appropriate? 89
2. For each TO, is the method for developing a transmission rate to derive the SECA obligation of each zone or sub-zone appropriate? 89
3. Has Alleghany Power demonstrated that it should be a separate sub-zone for the entire transition period? 89
Issue 3.C.3 : Has Allegheny Power demonstrated that it should be a separate sub-zone for the entire transition period? 102
D. Hubbing Adjustments: 102
1. For each proposed hubbing adjustment (including cascading hubbing), is the transaction appropriately shifted? 102

Issue 4: Shift to Shipper: A. Have entities seeking to shift SECA obligations to shippers provided sufficient showings pursuant to Paragraph 45 of the November 17, 2003 Order in Docket No. ER02-111? 107

Green Mountain's SECA Obligation: 146

IV. RULINGS ON PARTIAL SUMMARY DISPOSITIONS 164
A. CMS ERM 164
B. Green Mountain 169
C. Michigan Public Power Agency 173
D. Old Dominion Electric Cooperative 178
E. Ormet Primary Aluminum Corporation 180

V. CONCLUSIONS 184

VI. ORDER 185

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

I. INTRODUCTION

1. A number of compliance filings dealing with the implementation of the Seams Elimination Charge/Cost Adjustment/Assignment (SECA) were designated for hearing. This Initial Decision addresses the merits of the compliance filings and rejects the same because they do not comply with Commission rules and result in unjust, unfair and preferential rates.

2. During this proceeding a significant number of partial settlements have been filed. As a result of these partial settlements, in their briefs the parties noted that their arguments on some of the issues were addressed against some parties and not others. This Initial Decision does not note these distinctions, and leaves it to the parties on exceptions to make the pertinent disclaimers.

3. Additionally, this Initial Decision does not address arguments dealing with retroactive ratemaking and the filed rate doctrine for two reasons. First, these issues are pending before the Commission on requests for rehearing. Second, the substantive findings in the Initial Decision render these arguments moot.

II. PROCEDURAL HISTORY

4. The procedural history of these proceedings is extensive. They arise out of a series of Commission orders that consider the proposed integration of certain transmission-owning utilities into either the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) or PJM regional transmission organizations (PJM) (collectively, the RTOs). Specifically, the Commission was concerned with the economic and commercial effects of the seam between the Midwest ISO and PJM territories and set for evidentiary hearing the issue regarding the justness and reasonableness of the Midwest ISO's and PJM's rates for transmission service transactions that cross the seam and sink in the combined Midwest ISO and PJM service territories (the Combined Region).[1]

5. The July 23 Order addressed the Presiding Judge's decision not to eliminate the existing Regional Through and Out Rates (RTORs) based on his finding that he had no precedential authority to do so.[2] The Commission disagreed with the ruling and found "that the PJM and Midwest ISO RTORs, when applied to transactions sinking within the

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[1] *Alliance Companies, et al.*, 100 FERC ¶ 61,137 (2002).

[2] Midwest Indep. Transmission Sys. Operator, Inc., 104 FERC ¶ 61,105 at P 1, 10-12, 19-21 (July 23 Order on Initial Decision), reh'g denied, Ameren Services Co., 105 FERC 61,216 (Ameren), order on reh'g, Midwest Indep. Transmission Sys. Operator, Inc., 105 FERC ¶ 61,212 (2003) (November 17 Order).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

proposed Midwest ISO/PJM footprint, are unjust and unreasonable and must be eliminated" effective November 1, 2003.[3] As a result of the elimination of RTORs in the Combined Region, the Commission's November 17 Order directed the implementation of a two-year transitional lost-revenue recovery mechanism in response to concerns that inappropriate cost shifts would result.[4]

6. In order to minimize the amount of lost revenue to be collected through the SECA, the Commission required existing transactions (ETs) to continue to pay rates for through and out (T&O) transmission service during the 16-month period. *Id.* at P 9. In the now notorious paragraph 45 of the November 17 Order, the Commission, *inter alia*, addressed the economic efficiencies that would result from the elimination of RTORs and allowed Load Serving Entities (LSEs) under existing contracts that extend into the transition period to shift their obligation to the supplier under certain conditions (shift-to-shipper claims). *See id.* at P 45. Multiple shift-to-shipper claims arose from this statement and became the subject of many filed settlements.

7. Following a stakeholder led effort to develop a long-term transmission pricing solution for the Combined Region that would obviate the need to implement the two-year transitional rate design, the Commission's November 18 Order determined that the license-plate rate structure currently in place in the Combined Region should continue.[5] The November 18 Order directed the Midwest ISO and PJM to submit revised tariff sheets to implement the elimination of T&O rates and the adoption of the replacement rate design. The Commission ordered the filings to:

> (1) reflect December 1, 2004, as the effective date for elimination of through and out rates for reservations pursuant to requests made on or after November 17, 2003, for service commencing on or after April 1, 2004, for transactions to serve load within the other RTO where transmission service is taken under the open access transmission tariff of the other RTO; (2) reflect April 1, 2006 as the effective date for elimination of through and out rates for all transactions to serve load within the other RTO where transmission service is taken under the open access transmission tariff of

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[3] July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 2, 39. The Commission also found that "the through and out rates under the tariffs of certain individual former Alliance Companies may be unjust, unreasonable or unduly discriminatory or preferential and initiate[d] an investigation and hearing in Docket No. EL03-212-000 under Section 206 of the Federal Power Act (FPA)." July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 2; *see also* 16 U.S.C. § 824e (2005).

[4] *See* November 17 Order, 105 FERC ¶ 61,212.

[5] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168 at P 59-62, 66 (2004) (November 18 Order), *reh'g pending*.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

> the other RTO; and (3) incorporate the SECA mechanism as the transitional replacement rate effective December 1, 2004 through March 31, 2006.

November 18 Order, 109 FERC ¶ 61,168 at P 66 (citation omitted).

8. During the period November 24, 2004 through January 11, 2005, compliance filings were submitted by several transmission owners in the Combined Region that described the proposed SECA methodologies and developed and revised the corresponding SECA charges applicable to entities within the Combined Region.[6] These compliance filings established SECA rates for the first transition period, an initial 4-month period from December 2004 through March 2005 that were determined using calendar year 2002 as the test year. In the February 10 Order, the Commission accepted the compliance filings, subject to refunds and surcharge, and found that "the compliance filings have not been shown to be just and reasonable, and may be unjust and unreasonable, unduly discriminatory or preferential or otherwise unlawful" and set the compliance filings for hearing.[7] Judge H. Peter Young was designated as Presiding Judge. On March 4, 2005, a procedural schedule was established bifurcating the proceeding into two phases. Phase I involved issues dealing with SECA and Phase II the ship-to-shipper issues. Direct testimony supporting the first transition period's lost revenue amounts and corresponding SECA was filed on April 29, 2005 and May 13, 2005, respectively.

9. During the period March 31, 2005 through May 26, 2005, further compliance filings and revisions were submitted which proposed SECA for the remaining second transition period April 1, 2005 through March 31, 2006 based on a 2003 test year. On June 16, 2005, the Commission accepted the compliance filings,[8] subject to refund and surcharge, and consolidated that proceeding with the on-going hearing before Judge Young.[9] The June 21, 2005 order issued by the Chief Judge found good cause to suspend

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[6] *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,107 (2005) (February 10 Order).

[7] February 10 Order, 110 FERC ¶ 61,107 at P 39.

[8] The Commission also found that these filings may be "unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful." *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,409 at P 38 (2005) (June 16 Order).

[9] June 16 Order, 111 FERC ¶ 61,409 (the June 16 Order consolidated Docket Nos. ER05-6-014, -016, -017 through -022, -024, and -026, Docket Nos. EL04-135-016, -018 through -024, -026, and -028, Docket Nos. EL02-111-034, -036 through -042, -044, and -046, and Docket Nos. EL03-212- 032 through -038, -040 and -042 with Docket Nos. ER05-6 001, -002, -003, -005, -007, -009, and -013, Docket Nos. EL04-135-003, -004, -005, -007, -009, -011, and -015, Docket Nos. EL02-111-020, -021, -022, -024, -026, -

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the Track III hearing to allow Judge Young to hold a pre-hearing conference and recommend modifications to the procedural schedule. On July, 20, 2005 the Chief Judge extended the proceeding in light of the consolidation and established a hearing commencement date of May 17, 2006; Reply Brief due date of August 2, 2006; and an initial decision date of October 11, 2006. That same day, Judge Young subsequently issued an order that established a superseding procedural schedule for the consolidated proceedings. Direct testimony with supporting information as to the level of lost revenues and proposed SECA rates for both transition periods was filed on August 29, 2005. The parties submitted answering testimony on October 24, 2005, and FERC Staff submitted its testimony on November 22, 2005.[10]

10. The Commission's October 6 and September 12 Orders accepted compliance filings and erratas thereto, subject to refund and surcharge as appropriate, established hearing procedures and consolidated them into these proceedings.[11] In sum, the Commission's February 10, June 16, September 12 and October 2, 2005 Orders accepted and set for hearing a total of four sets of SECA implementation filings.

11. In a conference report accompanying the Energy and Water Development Appropriations Act, Congress stated, *inter alia*, that it expected "the Commission to review its SECA policies and take expeditious and appropriate remedial steps."[12] In response, on January 20, 2006, the Commission issued an order shortening the time for the initial decision and directed that the initial decision be issued by August 11, 2006.[13]

028, -031, and -033, and Docket Nos. EL03-212-017, -018, -019, -021, -023, -025, and -029).

[10] On September 7, 2005 Judge Lawrence Brenner was designated Settlement Judge. The parties pursued settlement discussions of the shift-to-shipper issue.

[11] *Midwest Indep. Transmission Sys. Operator, Inc.*, 112 FERC ¶ 61,267 (2005) (September 12 Order) (the Commission accepted for filing: (1) an errata filed by various parties; (2) a corresponding revised compliance filing submitted by the Midwest ISO and the Midwest ISO TOs; and (3) revisions filed by the Midwest ISO in compliance with the Commission's June 10 Order). The September 12 Order consolidated Docket Nos. ER05-6-029 (errata and revised compliance filing) and ER05-6-031 (compliance filing) in Docket No. ER05-6-001, *et al.*; *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,010 (2005) (October 6 Order) (the Commission accepted for filing proposed tariff revisions submitted by the Midwest ISO and the Midwest ISO TOs). The October 6 Order consolidated ER05-6-034 in Docket No ER05-6-001, *et al*.

[12] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,057 (2006) (*quoting* H.R. Rep. No. 109-275 (2005), Cong. Rec. H9911-12 (daily ed. Nov. 7, 2005) (Congressional Report).

[13] *Id.* at P 5.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

On January 30, 2006, the Chief Judge issued an order merging the two phases of the proceeding so that the consolidated dockets would be heard and decided together (January 30 Order). The January 30 Order established that the hearing would commence on May 1, 2006, Reply Briefs would be due on June 27, 2006 and the initial decision would be due August 11, 2006. In addition, the January 30 Order designated Judge Carmen A. Cintron as the Presiding Judge in place of the previously designated Judge Young.

12. On February 7, 2006 a further pre-hearing conference was held to establish a new procedural schedule. An order superseding and establishing a procedural schedule was issued that same day to set the remaining procedural dates for the hearing. Accordingly, the parties filed supplemental direct testimony for cascading hubbing/sub-zone and shift-to-shipper issues on March 1, 2006 and March 6, 2006, respectively. Answering testimony and exhibits were filed on March 27, 2006 and, additionally, reply and rebuttal testimony was filed on April 10, 2006. An order was issued adopting the list of issues on March 16, 2006. On March 20, 2006, an order confirming rulings was issued in which the procedural schedule was further modified to address the parties' arguments concerning their due process right to have adequate time to respond and perform discovery for claims shifted to them. Accordingly, testimony concerning new shift-to-shipper or "ripple" claims was due by March 27, 2006. The order also provided that a parties' failure to identify the amount and company name for each claim by that date would render such a claim procedurally barred. All responses to shift-to-shipper or "ripple" claims were due by April 10, 2006. Discovery terminated on April 24, 2006.

13. A Partial Initial Decision was issued on March 10, 2006 granting summary disposition to Aquila Merchant Services, Inc. (Aquila) and granting a cross motion for summary disposition to American Municipal Power-Ohio, Inc. (AMP-Ohio).[14] On March 30, 2006, oral argument was held to address several motions for summary disposition filed from the period March 9, 2006 through March 22, 2006: a motion for clarification filed by Ormet Primary Aluminum Corporation (Ormet) on March 14, 2006; and a motion for reconsideration of the March 10 Partial ID filed by the Indicated Transmission Owners (ITOs) on March 21, 2006. An order was issued on April 3, 2006, to confirm the following rulings from the bench concerning those motions: (1) Ormet's request for clarification was denied; (2) the Indicated Transmission Owner's motion for reconsideration was denied; and (3) motions for summary disposition were denied.[15]

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[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 63,037 (2006) (March 10 Partial ID).

[15] The following motions for summary disposition that were denied include: CMS Energy Resource Management Company (CMS ERM), ODEC, Ormet, Duquesne Light Company (Duquesne), and Green Mountain Energy Company (Green Mountain).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

The April 13 Partial ID[16] granted the motions for summary disposition filed by Dynegy Power Marketing, Inc. (Dynegy), DTE Trading, Inc. (DTET), and Cinergy Services, Inc. (Cinergy).[17] In addition, the April 13 Partial ID granted Public Service Electric and Gas Energy Resources and Trade's (PSEG) oral motion for summary disposition requested during the oral argument held on March 30, 2006.[18] With respect to the motions for summary disposition raised by DTET and PSEG, a cross motion for summary disposition was granted in favor of AMP-Ohio. April 13 Partial ID, 115 FERC ¶ 63,011 at 7-8, 13-14.

14. On May 1, 2006, the evidentiary hearing commenced and subsequently terminated on May 18, 2006. Initial briefs and reply briefs were submitted on June 9, 2006 and June 27, 2006, respectively. The following parties filed briefs.

Twenty parties filed both initial and reply briefs in this proceeding:

1. Allegheny Electric Cooperative, Inc., and Southern Maryland Electric Cooperative, Inc. (AEC-SMECO)
2. American Electric Power Service Corporation and Exelon Corporation (AEP/Exelon)
3. American Municipal Power – Ohio, Inc. (AMP-Ohio)
4. Baltimore Gas and Electric Company (BGE)
5. Certain Classic PJM Interconnection, L.L.C. Transmission Owners (Certain Classic PJM TOs)[19]
6. Commission Trial Staff (Staff)
7. Constellation Energy Commodities Group, Inc. (Constellation)
8. CMS Energy Resources Management Company (CMS-ERM)
9. The Dayton Power and Light Company (Dayton)

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[16] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 63,011 (2006) (April 13 Partial ID).

[17] Dynegy's motion was filed on March 16, 2006, DTET's on March 22, and Cinergy's on March 24, 2006.

[18] Tr. 631:5-632:8.

[19] The Certain Classic PJM Interconnection, L.L.C. Transmission Owners include: West Penn Power Company, Monongahela Power Company and The Potomac Edison Company (all doing business as Allegheny Power) (Allegheny Power); PPL Electric Utilities Corporation; Pepco Holdings, Inc. on behalf of its affiliates Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company; Public Service Electric and Gas Company; Baltimore Gas and Electric Company; Rockland Electric Company; and UGI Utilities, Inc. Electric Division.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

10. FirstEnergy Service Company and FirstEnergy Solutions Corp. (FirstEnergy)
11. Green Mountain Energy Company (Green Mountain)
12. Michigan Public Power Agency (MPPA)
13. Michigan South Central Power Agency (MSCPA)
14. Midwest Independent System Operator Transmission Owners (Midwest ISO TOs)[20]
15. Midwest Independent Transmission System Operator, Inc. (Midwest ISO)
16. Mirant Corporation (Mirant)
17. Ormet Primary Aluminum Corporation (Ormet)
18. Quest Energy, L.L.C., WPS Energy Services, Inc. and Strategic Energy L.L.C. (Quest/ESI)[21]
19. Virginia Electric and Power Company (Dominion)
20. Six Michigan Cities[22]

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[20] The Midwest ISO Transmission Owners for this filing consist of: Alliant Energy Corporate Services, Inc. on behalf of its operating company affiliate Interstate Power and Light Company (f/k/a IES Utilities Inc. and Interstate Power Company); Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, Central Illinois Light Co. d/b/a AmerenCILCO, and Illinois Power Company d/b/a AmerenIP; American Transmission Company LLC*; American Transmission Systems, Inc., a subsidiary of FirstEnergy Corp.; City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Duke Energy Shared Services, Inc. f/k/a Cinergy Services, Inc. for the Cincinnati Gas & Electric Co. d/b/a Duke Energy Ohio, Inc., PSI Energy, Inc. d/b/a Duke Energy Indiana, Inc., and the Union, Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc.; E.ON U.S. LLC (for Louisville Gas and Electric Company and Kentucky Utilities Company); Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; International Transmission Company*; Manitoba Hydro; Michigan Electric Transmission Company, LLC*; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company (Wisconsin), subsidiaries of Xcel Energy Inc.; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc. The Midwest Stand Alone Transmission Companies are denoted with an asterisk (*).

[21] These parties are three separate entities that will be referred to as Quest/ESI with the exception of the shift-to-shipper section.

[22] Six Michigan Cities include: the City of Bay City, Michigan (Bay City) and the Michigan Public Power Rate Payers Association (MPPRPA) (the latter comprising the Cities of Chelsea, Eaton Rapids, Hart, Portland, and St. Louis).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Five parties only filed an initial brief:
1. Duquesne Light Company (Duquesne)
2. Hoosier Energy Rural Electric Cooperative (Hoosier)
3. Multiple TDUs (MTDU)
4. Six Michigan Cities
5. Wolverine Power Supply Cooperative (Wolverine)

Two parties only filed a Reply Brief:
1. BP Energy Company (BP Energy)
2. Four TDU's[23]

15. Detroit Edison Company (Detroit Edison) and DTET submitted a letter in lieu of an initial brief stating that they have reached settlements that resolve all of their contested issues in these proceedings. Wisconsin Public Service Corporation and Upper Peninsula Power Company (the WPS Companies) filed a letter stating that they would not be filing an initial brief in this proceeding because it has reached an agreement with AEP/Exelon that resolves all the issues in the proceeding related to its SECA obligation. Madison Gas and Electric Company (Madison) submitted a filing stating that it would not file an initial brief since it has filed a settlement that resolves all issues with the PJM TOs. Madison notes, however, that it reserves its right to present and advocate its position regarding those issues in the event the settlement is not approved by the Commission.

16. As a result of the settlement discussions before Settlement Judge Brenner, almost all shift-to-shipper issues were settled. Judge Brenner issued a final report on May 2, 2006 stating that out of the 59 shift-to-shipper claims, including ripple claims, 41 had been resolved and 18 were at an impasse. The Chief Judge issued an order terminating Settlement Judge proceedings on May 3, 2006.

17. In addition, during the hearing, other substantive issues were settled. The parties have continued to file partial settlement agreements, even after the termination of the proceedings on May 18, 2006. As of August 10, 2006, 36 settlements have been submitted by the parties; 25 have been certified and 11 are currently pending. The Commission has approved 14 of these settlements. Since the timing and the terms of these mostly partial settlements amount to a "moving target," this Initial Decision will address the issues set forth in the Order adopting the list of issues agreed to by the parties. Many of the briefs contain various disclaimers and caveats as to the brief's applicability to certain issues and parties as a result of the partial settlements. In addition, by virtue of

[23] The Four TDUs include ODEC, Blue Ridge Power Agency (Blue Ridge), Central Virginia Electric Cooperative (CVEC), and Indiana Municipal Power Agency (IMPA).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the settlements, multiple exhibits, claims and/or portions thereof have been withdrawn or are pending withdrawal.

III. ISSUES

Issue 1: Test Period – Volumes

A. With respect to the filers' use of 2002 calendar year as the test period for the first four months of the transition period (December 2004 – March 2005):

1. Should adjustments be made to the entire 2002 calendar year or only the corresponding 4 months?

2. What adjustments/changes/modifications are appropriate for determining SECAs?

B. With respect to the filers' use of 2003 calendar year as the test period for the twelve months of the transition period (April 2005 – March 2006):

1. What adjustments to the 2003 calendar year are appropriate?

2. What adjustments/changes/modifications are appropriate to determine SECAs?

Background

18. In developing the SECA, two numbers are needed: revenues and throughput. This section deals with throughput. The next section deals with the dollar amounts. The third section then discusses how these numbers are allocated to various customer classes and how the SECA, a type of rate, is designed.

19. The throughput is a measurable volume for a specific time frame. There are a number of different ways to measure volume, including reserved quantities of transmission capacity, peak load, scheduled load, and delivered energy. In this case, regardless of which method of measuring volume is used, the determination of throughput starts first with actual, historical data for a fixed period of time, often referred to as "Period I" data or the "base period." The historical data is then adjusted (1) to eliminate non-recurring items, and (2) to reflect changes which are "known and measurable with reasonable accuracy" and which will become effective during the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

adjustment period. This second fixed period of time is called the "test period."[24] Thus, the test period is based on historical data, as adjusted for known and measurable changes.

20. In a typical natural gas pipeline rate case, the test period may not extend more than nine months following the historical period. In a typical electric rate case, the test period is a period of 12 months following Period I; it is called "Period II." This is not a typical case. First, this is a compliance filing to a FPA Section 206 proceeding; it is not a rate change proposal by a regulated utility under Section 205 of the FPA. Second, the Commission determined that instead of one historical period and one test period, there would be two historical periods called "test periods" and there would be two "transition periods." The two historical periods were to be calendar years 2002 and 2003. The first transition period was December 1, 2004 through March 31, 2005 and the second transition period was April 1, 2005 through March 31, 2006. November 18 Order at P 66.[25] Third, the transition periods did not immediately follow the historical periods. Finally, as a result of the Going Forward Principles Settlement, the first transition period was shortened from twelve months to four months, to start on December 1, 2004.[26] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,262 (2004) (Order Establishing Going Forward Principles).[27]

21. The issues to be determined in this section are (1) whether the reduction in the first transition period from twelve months to four months requires an adjustment to the length of the test period data, (2) what the appropriate volumes for the two test periods should be, and (3) whether a one-year test period should be used for developing the SECA for the entire 16-month transition period.

Compliance Filings

22. Mr. Heintz, on behalf of the Midwest ISO TOs used calendar years' 2002 and 2003 transactions crossing the Midwest ISO-PJM seam and sinking in PJM, except for

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[24] *See generally* 18 C.F.R. §§ 35.13(d)(1) to (3), 154.303 (2006) for definitions of "test period" for electric utilities and natural gas pipelines, respectively. Although the two sections are similar, the phrase "known and measurable" is only used in the definition of the test period for natural gas pipelines and to adjust Period I data in certain instances. It is referenced here as providing guidance on the type of changes which are permitted during a test period.

[25] *Order Accepting Compliance Filings*, 111 FERC ¶ 61,409 (2005) at P 4.

[26] Originally in the November 17 Order the transition period was to start on April 1, 2004. *See November 17 order* at P 43.

[27] S*ee also Midwest Indep. Transmission Sys. Operator, Inc*, 106 FERC ¶ 63,024 (2004) (Report of the Chief ALJ).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

grandfathered transactions, in determining the throughput to be used in calculating the SECA. Ex. MTO-1 at 21, MTO-7, 20, 31, 44. Mr. Heintz stated that he was not presented with known and measurable changes that would adjust his analysis. Midwest ISO TOs IB at 11 n.26; Tr. at 905:15-23.

23. On behalf of the New PJM Companies[28], Dr. Henderson supported SECA volumes, which included adjustments for the removal of grandfathered contracts, duplicate tags, and hubbing. AEP/Exelon IB at 11. AEP/Exelon argue that the throughput presented by Dr. Henderson, subject to final revisions to incorporate corrections noted in Dr. Henderson's Supplemental Direct Testimony, are reasonable and should be accepted. AEP/Exelon IB at 31 (citing Ex. PTO-122 at 10:13-11:12).

Parties' Contentions

24. AMP-Ohio, Strategic & Quest/ESI, Constellation and Ormet agree that the test period for the first transition period (December 1, 2004 through March 31, 2005) should not be based on a full year of 2002 data. For instance, AMP-Ohio argues that the four-month portion of calendar year 2002 that correlates to the four months of the first transition period should be used as the test period and adjustments should be made to remove data that are based upon the calendar months of April through November 2002. AMP-Ohio IB at 10-11. AMP-Ohio argues that by basing SECA obligations for the initial portion of the transition period on data that include the peak summer months of 2002, the TOs fail to reflect the expected use of the transmission system during the four months of the first transition period. Further, AMP-Ohio argues that the lost revenues that the TOs experienced during these months were overstated. AMP-Ohio acknowledges that the Commission "typically uses full test years" to develop rates; however, unlike the SECA charges at issue in these proceedings, rates are "typically" set for an indefinite period, not a discrete four-month period. AMP-Ohio RB at 4.

25. Quest/ESI support use of the corresponding four months of the calendar year subject to the SECA charge (*i.e.*, January-March 2002 and December 2002) for deriving lost revenues for the transition period. Quest/ESI also maintain that under this time period, the lost revenues will more closely correspond to the time period in which the rates are applied, and preserve the seasonal correlation between the derivation of the lost revenues and the application of SECA. This is important, they argue, because the summer months of June through August are "higher volume" months when many LSEs purchase additional summer-only capacity and energy to meet customers' cooling needs, which require additional transmission service to bring the power to load. Without an adjustment, Quest/ESI contend that a mismatch exists between the twelve-month historical period and the four-month transition period which will result in an

[28] The New PJM Companies are defined in footnote 41.

overstatement of the applicable rate. Quest/ESI contend that the Commission did not plainly state that calendar year 2002 in the context of a 16-month transition period should be used, rather, the Commission stated that SECA charges for Period I "are to based on 2002 test year" data. Quest/ESI RB at 5 (citing June 16 Order at P 4).

26. In response, the Midwest ISO TOs note that the Commission's June 16 Order clarified statements in earlier orders that the SECA charges for the first portion of the transition period "are to be based on 2002 test year data." Midwest ISO TO RB at 7 (citing June 16 Order at P 4). Further, the Midwest ISO TOs highlight that, despite discussions that the first part of the transition period would be four months, the Commission did not require an adjustment to use a portion of the 2002 test year. *Id.*

27. Similarly, AEP/Exelon argue that using data from any year other than 2002 to calculate SECAs for the first four months of the transmission period would not comport with the Commission's orders. AEP/Exelon do not, "on principle," oppose basing the four months of the first transition period SECA charges on the corresponding four months of 2002 data, provided that the adjustment is made for all non-settling parties. AEP/Exelon IB at 12. However, AEP/Exelon oppose this change as "impractical;" stating that its implementation would require substantial additional data collection and analysis. *Id.*

28. Ormet argues that the 2002 test period contains anomalous data and is not reliable. Such anomalous data includes:

- The advent of power marketers that made it almost impossible to calculate directly the transmission charges paid to TOs because of the increased number of transactions involving power marketers who do not have detailed bills showing the amount of transmission charges paid by the power marketers, nor do the bills show to whom the marketers paid the transmission charges. Ex. MTO-1 at 23.

- The Midwest ISO was formed in February 2002 and trading patterns changed. Tr. at 878:9-15.

- Allegheny Power joined PJM in April 2002, dramatically changing trading patterns from flows through Dominion to PJM to flows through Allegheny Power to PJM. Tr. at 1124:8-20.

- OATi tag data did not require identification of specific sinks until April 10, 2002. Ex. ORM-2 at 51 n.49.

- PJM's estimated T&O revenues for 2002 are triple the 2003 estimate. This remains unexplained in this record. ORM IB at 26-27.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

- MPPA had abnormally high imports in 2002 due to the impact of a tornado. MPPA IB at 13.

- Hoosier experienced abnormally high imports from AEP in 2002 due to an unusually long outage at one of Hoosier's 500 MW units and extraordinarily high temperatures during the summer of 2002 in Hoosier's service territory. Hoosier IB at 4-5.

- Ormet's known and measurable decrease in load can be attributed to factors other than the elimination of the RTOR – its bankruptcy proceeding, its labor dispute, the disruption in its supply of raw materials due to the closing of the Ohio River to commerce, the sale of the rolling mill to Aleris International Inc. and the subsequent dismantling of the mill. Tr. at 2211:20-2214:3, 2215:4; Ex. ORM-1 at 3:9-15.

Ormet therefore argues that 2003 should be used as the test period for the entire transition period and that 2002 should not be used at all. Ormet states that while some adjustments may still be needed to 2003 data, 2003 is a better proxy for future trading patterns because the 2002 changes are already accounted for in 2003 data. Ormet IB at 28.

29. AEP/Exelon reply that Ormet's proposed adjustment to remove the 2002 test year should be rejected. According to AEP/Exelon, use of 2002 as a test year is an issue pending on rehearing and must be decided by the Commission. AEP/Exelon maintain that if the Commission had not intended to use 2002 data if more recent test year data became available, the Commission would have reversed its earlier ruling adopting 2002 as the test year for the first phase of the transition period. AEP/Exelon also point out that in the February 10 Order or June 16 Order the Commission did not suggest that either the 2002 or 2003 test years were inappropriate or inconsistent with prior Commission orders.

30. Rather than using a test period from 2002 or 2003, Quest/ESI suggest that the SECAs should be based on contemporaneous billing units for the transition period. Quest/ESI maintain that the result would be a rate that reflects the lost revenues for the TOs, as well as the changes that have occurred in the MISO and PJM markets that have reduced cross border activities, independent of the elimination of the RTOR. Quest/ESI therefore recommend that costs should then be assessed on all MWhs in the Combined Region. Quest/ESI IB at 19-21.

31. In response, AEP/Exelon contend that use of the transition period as a contemporaneous test period would defeat the Commission's purpose in eliminating transactional charges for T&O service. Similarly, the Midwest ISO TOs argue that the Commission expressly rejected suggestions to base the SECA charges on actual usage, and urge the Presiding Judge to reject Quest/ESI's arguments, that the actual reservations should be used as a contemporaneous test period, as an improper collateral attack on the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Commission's orders. Midwest ISO TOs RB at 7. The Midwest ISO TOs assert that the Commission has already ruled on the test period, and only the Commission can reconsider that ruling.

32. BGE argues that the compliance filings have violated the test period approach of ratemaking where "atypical" and "extraordinary" events that occur within the historical period, as well as events occurring within a test period that are not expected to reoccur, are removed before setting rates for a future period. First, BGE argues that transactions that did not continue into the transition period should not be included in the calculation of the SECA. Second, BGE alleges that none of the compliance filings removed T&O transactions that ended during the test periods. Third, BGE alleges that AEP/Exelon failed to make the proper offsetting reductions from raw historical figures in calculating the throughput used for the calculation of lost revenues. Fourth, BGE alleges that the SECA filings "purposefully" include every transaction occurring within the periods regardless of whether the transactions continued beyond the test period, thereby insuring the inclusion of costs that are non-recurring. Fifth, BGE claims that the proposed SECAs have a built-in over-recovery feature because the test year period fails to reflect subsequent load growth. Finally, BGE contends that that new reservations in the transition period are not contained in the test year data. Therefore, BGE argues that the Midwest ISO TOs have an obligation to make the adjustments to the initial figures to avoid mistakes and rates different from those that would replicate costs. BGE IB at 18-24; RB at 5-10.

33. In response to BGE's position, AEP/Exelon contend that BGE erroneously assumes that SECAs should have been charged to T&O transactions that extended into the transition period. AEP/Exelon also contend that BGE did not provide evidentiary support for its assertions that SECAs are a double charge to LSEs. Also, the Midwest ISO TOs disagree with BGE's claims that the test period data should be adjusted to reflect transactions that ended prior to the transition period. They maintain that BGE should have asserted known and measurable changes in testimony and exhibits.

34. Hoosier had unusually high level of imports during 2002 as a result of an outage related to Merom Unit 1, unplanned maintenance of other units in the summer period and a forced outage in Ratts Unit 1 from July 11 to July 19. Hoosier IB at 4. Additionally, its service territory had unusually high temperatures during the summer of 2002. Consequently, Hoosier argues that the significant imports are unlikely to reoccur and constitutes a known and measurable change. *Id.*

35. Green Mountain, MPPA, Ormet and Quest/ESI propose specific changes to the throughput levels set forth in the compliance filings. The specific proposals will be discussed below.

36. Ormet argues that in the November 17 Order, the Commission was attempting to

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

resolve the competing concerns of using the most recent test period data while still enabling parties to make compliance filings as soon as possible. Ormet maintains that the Commission would have preferred to use a 2003 test year for the entire transition period, but did not because it was not feasible to do so at the time because the data would not have been in usable form in time for a transition period beginning April 1, 2004. Ormet argues that when the start date of the transition period was moved from April 1, 2004 to December 1, 2004, the concern that 2003 test year data would not be available in time for the beginning of the test period was alleviated. Therefore, Ormet proposes the use of 2003 as the test period for the entire transition period as 2003 data more closely reflects future trading patterns and more closely reflects cost collected from loads with the benefits that loads will receive from the elimination of the RTOR. In addition, Ormet maintains that 2003 provides more accurate data, and will require fewer adjustments, including those for known and measurable differences. Finally, Ormet also argues that the burden of modifying the compliance filings to use 2003 test period data for the entire transition period would be minimal, as the data has already been compiled. Ormet IB at 20-29; Ormet RB at 8-9.

Discussion/Findings/Conclusions

37. The Commission has already determined some of the parameters to be used in developing test year volumes. For example, the Commission rejected a proposal made by the Midwest ISO TOs to use the calendar year 2001 as the historical period for the two-year test period. This proposal was set forth in the November 14, 2004 testimony of Mr. Heintz, which was used by the Commission in providing guidance on how the SECA mechanism should be developed. July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 54. Mr. Heintz recommended that 2001 calendar year be used. He stated:

> Using data for the initial period after the Midwest ISO's startup period presents problems as the market was adjusting to the Midwest ISO's role as a transmission provider, and the Midwest ISO was working through issues related to transmission rate discounting and ATC [available transfer capability] calculations.

Ex. ORM-4.

38. Subsequently, however, the Midwest ISO TOs, as well as the New PJM Companies, recommended that more recent throughput data be adopted. November 17 Order, 105 FERC ¶ 61,212 at P 66. Nevertheless, the Commission did not adopt a historical period which would not recognize the changes in the market. Rather, the Commission provided guidance that it wanted the most recent twelve-month data used, with adjustments for known and measurable differences, to most closely reflect future trading patterns. *Id.* at 64 (referring to *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 63,049 at P 92 (2003) (Initial Decision)). Thus, the Commission stated that

"[e]liminat[ion] of the RTORs only for new transactions during the transition period will minimize the lost revenues to be recovered through the lost revenue recovery mechanism." November 17 Order, 105 FERC ¶ 61,212 at P 14.

39. Further, in developing parameters for the appropriate approach for determining throughput, the Commission also rejected a proposal to use actual invoices instead of NERC tag data for the test period:

> We reject the suggestion of some parties to base SECA charges on actual invoices, instead of NERC [OATi] tag data, to ensure that the SECA does not charge parties more than the actual RTOR charges paid in the test period. Using actual invoices as the basis for the SECA charges could lead to under recovery of lost revenues and produce unfair results as many of the transmission customers are marketers that can change their level of trading activity from year to year.

Id. at P 67.

40. The Commission clearly wanted the test period to reflect future trading patterns. Trading patterns vary seasonally. During the peak summer months, energy usage and transmission volumes are relatively high, whereas during off-peak months, load is much lower. LSEs recognize this fact in contracting for energy and transmission services. For example, Mr. Norton explained that AMP-Ohio arranged summer-only schedules to meet the summer peak needs of its members. Ex. AMP-1 at 29. Further, AMP-Ohio's argument is found persuasive. Use of the entire year allows the TOs to recover, as SECA revenues, amounts they already recovered in T&O revenues, since the RTORs were not eliminated until December of 2004. As Mr. Norton testified, the TOs recovered their peak-period revenues during the summer of 2004, since the T&O rates were not eliminated until December of 2004. *Id.*

41. AEP/Exelon contend that for the first historical period, it would be impractical to use any time frame other than the entire 2002 calendar year. AEP/Exelon's contention is not persuasive. Dr. Henderson conceded that the use of only four months from 2002 is "not unreasonable" and "may be a better indicator of the pattern of imports and therefore the pattern of the benefits, during the particular four months at issue." Dr. Henderson also noted that it would be a "straightforward matter" to calculate the MWh (volume) data. Ex. PTO-81, 43:18-44:5.

42. Because of the seasonal nature of energy throughput, the record supports the reduction in the length of the first test period to correspond to the reduction in the length of the first transition period. Therefore, if the Commission requires the use of 2002 throughput data, on exceptions to this Initial Decision, then it is recommended that the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

new compliance filings should reflect the same months from 2002 as are reflected in the transition period (*i.e.*, January through March and December).

43. Mr. Russell recommends that more recent data, the 2003 historical throughput, adjusted for known and measurable changes, be used as the test period for the entire transition period. This recommendation is found to be just and reasonable for several reasons. First, it reflects the most recent time frame for which data would have been available when the first compliance filings were made. Second, it does not require the use of non-contiguous months (*i.e.*, January through March and December) for the 2002 historical period. Third, it recognizes that the NERC e-Tag Version 1.6, which was used until April 10, 2002, did not require specific sinks to be listed, thereby requiring alternative methods for identifying sinks for the beginning of 2002. *See* Ex. ORM-2, 51 n.49. Fourth, the four months in 2002 are not a good proxy for trading patterns in January through March 2005 since many of the changes had not yet taken place. Fifth, as discussed below, the revenues for 2002 are inexplicably much higher than the revenues for 2003, thus 2003 provides a better proxy for revenue purposes. Finally, calendar year 2003 provides for administrative convenience. Although data for the four months of 2003, as adjusted, should be readily available, given the fact that 2002 only represents 25 percent of the historical period, it would be administratively prudent to use the more recent data.[29]

44. Green Mountain argues that its SECA should be reduced by 50 percent due to reduced usage of the PJM-MISO seam in the transition period. This issue will be addressed below. Green Mountain IB 16.

45. The adjustment for known and measurable differences proposed by MPPA and the Four TDUs in conjunction with their motion for summary judgment are addressed below.

46. Ormet argues that the 2003 calendar year data must be adjusted for known and measurable differences. Ormet alleges that it had a significant decrease in load between the test periods and transition period, and its purchasing pattern also changed when the supply contracts, under which it purchased power, expired at the end of the first month of the transition period. Specifically, Ormet's load dropped from approximately 535 MW of non-AEP, non-grandfathered load in 2002 to approximately 8 MW during the transition period. Ormet IB at 51 (citing Ex. ORM-2 at 41:6-7). This reduction is due to a reduction in consumption by Ormet since it had to curtail its operations and the load is no longer there.

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[29] Should the Commission not adopt this finding, the use of the four months of 2002 is the best alternative. Through the rest of this Initial Decision, corresponding changes to meet this alternative will be provided.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

47. Quest/ESI claim that there are two known and measurable changes that should be reflected because the service did not extend into the transition period. First, Quest/ESI argue that deliveries to Northern Ohio Aggregation Coalition under a PPA with AEP Marketing should be removed because service was for the period of January 1, 2003 through December 31, 2003. Ex. QST-1 at 33, Ex. QST-8. Second, Quest/ESI argue that deliveries to North Star Steel should be removed because Quest stopped serving this retail load in April 2004. *Id.* at 40; Ex. QST-1 at 19-20, Ex. QST-5. Quest/ESI IB at 39-40.[30]

48. In response to Quest's proposed adjustments, AEP/Exelon note that the Commission did not require the compliance filings to include adjustments for known and measurable differences based on changes that occurred during the transition period. AEP/Exelon IB at 36-39. AEP/Exelon further note that although the concept of known and measurable differences has a specific regulatory meaning for traditional rate cases, this is not a traditional rate case. AEP/Exelon argue that the standards set forth in the Commission's regulations for cost of service rate cases – which permit adjustments for known and measurable differences that occurred after the test period -- must give way to a standard that is specially tailored for this unique proceeding. According to AEP/Exelon, the appropriate standard for known and measurable differences in this proceeding is one that limits such adjustments to anomalous circumstances that existed during the 2002 and 2003 test periods. AEP/Exelon IB at 39.

49. The contract expiration issue was previously addressed in two Partial Initial Decisions issued in this case. *See* March 10 Partial ID, 114 FERC ¶ 63,037; *see also* April 13 Partial ID, 115 FERC ¶ 63,011 (collectively, the Partial Initial Decisions). The March 10 Partial ID stated there "that the Commission envisioned that the SECA would apply to transactions involving reservations pursuant to requests made on or after November 17, 2003 for service commencing after April 1, 2004." March 10 Partial ID, 114 FERC ¶ 63,037 at P 16. As a result, the Partial Initial Decision determined "that SECA charges are for contracts for delivered power that continue into the transition period." *Id.* This Partial Initial Decision also found that SECA could not be imposed based on a contract that terminated prior to the transition period. *Id.* This was considered consistent with principles of cost causation since power was not delivered during the transition period based on such contract. *Id.* at 18. Thus, there are no "lost revenues" associated with the contract. *Id.* at 17.

50. This is sufficient to resolve the issues raised by Quest/ESI, BGE and Ormet in their favor. Accordingly, as previously found in this case, it is concluded that Quest and Ormet should not have been imposed a SECA based on the contracts that expired in the test period. This same result would be reached below based on the findings concerning

[30] Alternatively, Ormet requests summary disposition on this issue.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

rate design. Quest's proposed adjustments to the test period should be reflected in the new compliance filing. It was argued that the previous decisions only addressed shift-to-shipper issues and are not applicable to other contracts. These arguments are meritless. The findings in the Partial Initial Decisions are based on interpretation of the Commission's prior orders in this case. Furthermore, there is nothing that distinguishes the contracts discussed here, from the contracts discussed in the Partial Initial Decisions. A known and measurable change can occur after the test period, before the proposed effective date of the rate at issue and has to be known and measurable with reasonable accuracy at the time of the filing. A known and measurable change need not be a change that arises during the test period. For example, a known and measurable change is a post-test period change that need only be known and measurable at the time of the filing. *See, e.g.*, *Colorado Interstate Gas Co*.,106 FERC ¶ 61,275 (2004); *Northern States Power Co.*, 67 FERC ¶ 61,240 (1994); and *El Paso Electric Co*., 18 FERC ¶ 61,193 (1982). In each of these cases, the change was known and measurable prior to the effective date of the rate.

51. In addition, in *Southwestern Public Service Co. v. FERC*, 952 F.2d 555 (D.C. Cir. 1992) (*Southwestern*), the D.C. Circuit specifically rejected, as a "stray remark," an Administrative Law Judge's "suggestion that post-period changes could never give rise to a spot adjustment." *Southwestern*, 952 F.2d at 559. The court, after reviewing precedent on the subject concluded: "[g]iven this precedent, the absence of any apparent reason why adjustment for post-period change would cause any more difficulty than adjustment for an in-period change, and the absence of any FERC decision clearly supporting the distinction, we find no basis for this limitation." *Id.*

52. In the *Southwestern* rate case, after both Period I and Period II had ended, Congress enacted tax legislation that reduced the corporate income tax rate. The contents of tax legislation was not known and measurable until it was enacted. Furthermore, the actual tax rate change took place a year after Period II, and longer than that after Period I. The post-test period adjustment was proper because it was known and measurable when the Commission ruled.

53. Similarly, in *Distrigas of Mass. Corp. v. FERC*, 737 F.2d 1208 *vacated on other grounds*, 751 F.2d 20 (1st Cir. 1984) (*Distrigas*) the court held that "[c]ase law does not rigidly tie a regulator to the use of test-year figures, when later information reveals that the estimates based on those figures are likely to be seriously in error." *Distrigas*, 737 F.2d at 1220. The court explained that "to fail to adjust past figures may well lead to serious mistakes, creating rates radically different from those that would replicate costs or serve other valid regulatory purposes." *Id.*

54. BGE argues that the compliance filings submitted by the Midwest ISO TOs are deficient and fail to meet the threshold requirement of showing that the test period data is accurate and reasonable. The record supports BGE's position. As succinctly stated by

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Mr. Heintz, the Midwest ISO TOs did not present him with any known and measurable changes that would alter the historical data for calendar years 2002 and 2003. Tr. 905:15-23. This is an admission against interest. Parties to this proceeding repeatedly presented evidence of known and measurable changes. However, this fell on dead ears.[31] The inferences to be drawn from this are that the TOs did not care to comply with the Commission's requirements that the historical data be adjusted for known and measurable changes. The second inference to be drawn is that the TOs had predetermined how much money they wanted to recover in alleged "lost revenues" and then "they made it so."

55. The Midwest ISO TOs have an obligation to make adjustments to the initial figures to avoid mistakes and rates different from those that would replicate costs or serve other regulatory purposes. In this case, the purpose of using a test period approach is to reflect changes which will occur during the transition period. By failing to reflect such known and measurable changes, the Midwest ISO TOs are merely replicating historical data. *See Distrigas*, 737 F.2d at 1220. The administrative reasons for requiring changes prior to the effective date are applicable to this situation: rate certainty and closing the record.. In the instant case, the changes were known and measurable at the time of filing and prior to the collection of the SECA.

56. The compliance filing imposes a SECA obligation on Ormet based on its historical usage when Ormet was at full production. In December of 2004 Ormet's peak load was 195 MW. Ex. ORM-2 at 41. By mid-January 2005, Ormet's load had gone down to 22 MW. Ex. ORM-2 at 52. On November 2005, Ormet announced the sale of the equipment at its rolling mill and its load dropped to 8 MW.[32] Ormet's changes in load were known and measurable at the time of the filing of the PJM rates for each of the five rate periods contemplated in the compliance filings.[33] It is found that Ormet's load diminution is a known and measurable change. The compliance filings must reflect this finding. Ormet filed a request for summary disposition based on these issues which is addressed below.[34]

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[31] It is noted that the MISO TOs did settle with Ormet. Ormet RB at 27.

[32] AEP's witness Bethel agreed that some adjustments may be appropriate for Ormet. Ex. AEP-9 at 4:12-15.

[33] TOs started collecting the SECA from LSEs on June 1, 2005.

[34] Ormet is the standard bearer of the SECAs. The compliance filings do not properly reflect the reduction in usage. For example, Ormet's monthly energy was reduced from 140,186 MWh in December 2004 to 7.8 MWh in March 2006. Although Ormet's March 2006 usage was only four percent of its December 2006 usage, its proposed SECA for the last month of the transition period is a whopping 42 percent of its first month's SECA obligation. A rate methodology which has this type of discrepancy is not just and reasonable.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

57. Hoosier has presented significant evidence to demonstrate a known and measurable change for its high usage in 2002. Ex. HE-2 at 6-8. This 2002 usage was the result of specific circumstances which have not been repeated and its 2003 usage was more reflective of the test period usage. As a result, it is found that Hoosier's throughput should have been adjusted for known and measurable changes.[35] Accordingly, the compliance filing should reflect this finding also.

58. If the Commission adopts the rate design findings below, some of these known and measurable changes issues become moot.

Issue 1. C: Is the Analysis of the OATi tag data to identify, and to allocate a SECA responsibility to, importing zones or sub-zones adequately supported?

59. This issue is discussed below in the section dealing with zones and sub-zones.

Issue 1. D: Are MWs for grandfathered contracts and duplicate tags properly removed?

60. AMP-Ohio identified MWhs associated with grandfathered contracts that had not been properly removed from the calculations and corrections have been submitted and it is found the corrections should be made. Furthermore, the imports from the New York Power Authority pursuant to grandfathered agreements should not have been in the SECAs. The correction submitted by Dr. Henderson for this matter needs to be made. Ex. S-3. Mr. Heintz corrected the sink code of grandfathered transactions provided by Ameren. Ex. MTO-103 at 27, Ex. S-3 at 3. It is found that this correction needs to be made.

Issue 2. Lost Revenues -- General

A. What are the through and out lost revenues of each Transmission Owner?

C. Should there be any adjustments to the lost revenues? What should those adjustments be?

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[35] *See generally, Williston Basin Interstate Pipeline Co.,* 84 FERC ¶ 61,081, 61,368 (1998) (non recurring costs may not be included in the cost of service because they distort the level of representative expenses that are expected to be incurred in the future).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Background

61. As mentioned in the "test period -- Volumes" section, two numbers are needed for developing the SECA – revenue amounts and volumes. The previous section addressed volumes; this section will address the revenue amounts. A review of the testimony, exhibits, transcripts and briefs indicates that the terms used for defining the dollar amounts are either not used consistently or are used interchangeably. For example, "lost revenues" were used to mean "revenues for T&O transmission service during the historical periods." *See, e.g.*, Tr. at 958:11-14, 1118:6-10; Ex. MTO-5, at 1, col. (4); Ex. PTO-3, col. (4). "Lost revenues" has also been used to mean "revenues to be recovered during the transition period." *See. e.g.*, Dayton IB at 13. To provide clarity, this Initial Decision defines the dollar amounts as follows:

- "T&O revenues" are revenues collected during the historical periods for T&O or RTOR transmission service within the Combined Region.

- "Lost revenues" are revenues that would have been collected as T&O transmission rates or RTORs during the period of December 1, 2004 through March 30, 2006, *but for* the Commission's determination that such rates are unjust, unreasonable and unduly discriminatory. Since the T&O rates and RTORs were eliminated, there were *no* revenues for cross-border service during this time frame. Nevertheless, the term "lost revenues" is the shorthand term used to describe those "*but for*" revenues. "Lost revenues" do not include revenues for grandfathered transmission services or revenues for "existing transactions," *i.e.*, long-term transmission services with reservations made after November 17, 2003 and effective dates prior to April 1, 2004.

- "SECA revenues" are revenues collected during the transition period. They equal the SECA multiplied by transition period volumes.

Midwest ISO TOs' Compliance Filing

62. In their compliance filings, the Midwest ISO and the Midwest ISO TOs' jointly submitted *pro forma* Schedule 21 of the Midwest ISO open-access tariff, which sets forth lost revenues as monthly amounts.[36] The compliance filings, as supplemented by the testimony of Mr. Heintz, used a six-step process to analyze the OATi tag data, develop an average rate, and calculate the lost revenues. Steps one through three and six are

[36] The Midwest ISO and the Midwest ISO TOs made compliance filings on November 24, 2004, December 1, 2004, December 2, 2004, December 17, 2004, December 29, 2004, January 11, 2005, February 7, 2005 and March 31, 2005.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

relevant for the development of the Midwest ISO TOs' lost revenues. The other two steps deal with allocation and rate design issues and will be discussed in a later section of the Initial Decision.

63. Step 1 of Mr. Heintz' methodology requires three calculations: (1) the calculation of the T&O revenues during the time periods that the TOs were not part of the Midwest ISO and were themselves transmission providers; (2) the calculation of the T&O revenues associated with the Mid Atlantic Power Pool (MAPP) regional tariff for Midwest ISO TOs that are also MAPP members; and (3) the calculation of the T&O revenues for the Midwest ISO as the transmission provider. For all calculations, T&O revenues are based on the actual billing determinants and actual rates (including discounted rates) during the test years, from sources such as FERC Form No. 1, OASIS data, Rural Utility Service Form No. 12, or Energy Information Administration Form No. 412, with out-of-period adjustments and refunds for prior periods excluded. Midwest ISO TOs IB at 17-19.

64. The first calculation is to determine T&O revenues for the time periods that the TOs were not part of the Midwest ISO, but rather, were individual transmission providers. Because the Midwest ISO did not start regional transmission open-access tariff service until February 1, 2002, all Midwest ISO TOs calculated their own T&O revenues for the month of January 2002. In addition, for the time frame between February 1, 2002 and the date a TO became a member of the Midwest ISO, the individual TO provided Mr. Heintz its own T&O revenues. For METC, this time frame extended through April 2002; for ATSI and NIPSCO, it extended through September 30, 2003; and for AmerenUE, AmerenCIPS, AmerenIP, the time frame extended through December 31, 2003. *Id.* [37]

65. The second calculation is to determine T&O revenues related to MAPP transactions for those MAPP TOs who also became MISO TOs, *i.e.*, Alliant, ATC, Great River Energy, Manitoba Hydro, Minnesota Power, MDU, Northern States Power, and Otter Tail. Mr. Heintz included the Schedule F revenues for the MAPP regional tariff because MAPP members had revenues associated with Schedule F charges which were

[37] For purposes of calculating lost revenues Mr. Heintz subdivided both rate periods (one and two) to accommodate the fact that Duquesne Light Comapany became a member of PJM on January 1, 2005 and Virginia Electric and Power Company (Dominion) became a member of PJM on May 1, 2005. The first portion of rate period one covers December 1, 2004 – December 31, 2004; the second portion covers January 1, 2005- March 31, 2005 (including Duquesne). The first portion or rate period two covers April 1, 2005-April 30, 2005; the second portion covers May 1, 2005-March 31, 2006 (including Dominion). Ex. MTO-1 at 9:1-15.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

eliminated with the Midwest ISO RTOR for transactions sinking in PJM.[38] Midwest ISO TOs IB at 19-20.

66. The third calculation is for the months of 2002 and 2003 when the Midwest ISO TOs were members of the Midwest ISO. This reflects the revenues the Midwest ISO TOs received for T&O service under the Midwest ISO open-access tariff. The Midwest ISO open-access tariff is a regional tariff that recovers revenues and then allocates those revenues back to its member TOs. Consequently, the Midwest ISO TOs' respective shares of the Midwest ISO T&O revenues are based on the Midwest ISO Revenue Distribution Reports. Midwest ISO TOs IB at 20.

67. In Step 2, Mr. Heintz and the Midwest ISO TOs obtained the OATi data and summarized the total through and out MWhs from the OATi tag data. OATi, the entity that keeps the NERC energy scheduling data, produced reports summarizing how many MWhs each TO transmitted that sank in each zone in the Combined Region. OATi tag data shows information regarding transmission transactions including the MWhs, the sink, the market path, the physical path, and energy and transmission profiles. Mr. Heintz adjusted the OATi tag data for 2002 and 2003 to: (1) correct spelling errors; (2) use a uniform naming convention; (3) split the control area data for MECS into two transmission zones, METC and ITC; (4) split several control area data to exclude transmission zones where a TO is not a member of Midwest ISO; and (5) adjust control area boundaries and the transmission system boundaries that are not identical to ensure that the load is reflected in the proper transmission zone.

68. In Step 3, Mr. Heintz calculated the total MWhs for all T&O transactions, excluding grandfathered transactions and adjustments. Finally, in Step 6, the Midwest ISO TOs reconciled their 2002 and 2003 open-access tariff out and through revenues and associated MWhs to FERC Form No. 1 or other operating reports to ensure the accuracy of the open-access tariff out and through revenue calculation for the months that the TO was not in the Midwest ISO. Midwest ISO TOs IB at 15-43.

AEP/Exelon Compliance Filing

69. As noted in the background section, AEP by itself or with other TOs, and/or PJM together with various PJM TOs, submitted compliance filings to establish, *inter alia*, lost revenues.[39] The AEP proposal included a proposed SECA mechanism as Attachment X

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[38] Tr. 966, *l.* 24 – 967, *l.* 18.

[39] Eleven compliance filings were made: November 24, 2004 (PJM and PJM TOs), November 24, 2004 (AEP), December 13, 2004 (AEP, ComEd and Dayton), March 22, 2005 (AEP, ComEd, Dayton and Duquesne), March 25, 2005 (AEP, ComEd, Dayton and Duquesne), April 20, 2005 (PJM), April 22, 2005 (AEP, ComEd, Dayton and

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

to the PJM open-access tariff. These overall compliance filings were supported by the testimony of Dr. Henderson on behalf of AEP, Dayton, Exelon, and Dominion. Additional witnesses testified to the level of T&O revenues for their respective TOs.

70. AEP and ComEd, a subsidiary of Exelon, calculated their T&O revenues for 2002 and 2003 based on actual billing determinants and rates charged for Point To Point transmission service through and out of their respective systems to PODs in the Combined Region. AEP witness, Mr. Bethel, supported AEP's claim for T&O revenues, and Exelon's witness, Mr. Bustard, reviewed internal billing data and OASIS reservation data to verify its T&O revenues. Ex. AEP-1 at 10:18-11:7; AEP-2 and AEP-3.

71. Both witnesses removed grandfathered transactions. AEP/Exelon IB at 19. The estimated T&O revenues for PJM for 2002 and 2003 are approximately $48 million and $18.5 million. Due to the correction to the 2003 PJM average rate, PJM T&O revenues for 2003 will need to be restated in a future compliance filing. AEP/Exelon IB at n.54.

72. To determine 2002 revenues for AEP, Mr. Bethel made the following adjustment. He added revenues to the 2002 T&O revenues that are associated with In-Out transactions.[40]

73. AEP/Exelon contend that AEP's adjustment for In-Out transactions during 2002 is reasonable because a significant portion of the energy delivered by AEP to Dominion, and lesser amounts of other deliveries to other PODs outside the Combined Region, was scheduled for ultimate delivery to loads within the Combined Region, *i.e.*, to "sinks" within the Combined Region. In-Out transactions represent $4.2 million of revenues ($12.7 million on an annualized basis, but only during the first four months of the transition period). AEP/Exelon IB at 19-20.

74. Mr. Bethel's removal of transactions for deliveries from AEP-East to AEP-West located in the Southwest Power Pool region, reflects the fact that the AEP open-access tariff did not impose exit fees on network customers in the AEP-West zone when they use the facilities in AEP-East (or vice versa). *Id.*

75. AEP/Exelon note that as a result of the entry of new TOs within PJM at various times during the transition period, and the annual revision to billing determinants under

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Duquesne), April 29, 2005 (AEP, ComEd, Dayton and Dominion), May 3, 2005 (AEP, ComEd, Dayton and Dominion), June 13, 2005 (AEP, Exelon, Dayton and Dominion) and January 31, 2006 (AEP, ComEd, Dayton and Dominion).

[40] The term "In-Out" refers to transactions that cross a seam within the Combined Region and sink outside the Combined Region. AEP/Exelon IB at 7, 29.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the PJM open-access tariff, five different effective periods for SECAs have been established: (1) December 1, 2004-December 31, 2004; (2) January 1, 2005-March 31, 2005; (3) April 1, 2005-April 30, 2005; (4) May 1, 2005- May 31, 2005, and (5) June 1, 2005-March 31, 2006. Ex. AEP-1-3.

76. PECO Energy Company (PECO) is a subsidiary of ComEd. PECO's claimed T&O revenues are supported by Mr. Bustard and Dr. Henderson, with reliance upon the revenue calculations presented by PJM's witness, Mr. Dessender, in testimony submitted on behalf of PECO. Exs PECO-1; EXE-1 at 8; and PTO-1 at 23. Mr. Bustard recommends how the revenues presented in Mr. Dessender's testimony should be treated in the determination of PJM lost revenues and Dr. Henderson calculates PJM lost revenues on behalf of PECO. Mr. Bustard recommends that all revenues for firm T&O service, except those with a POD of the New York Independent System Operator (NYISO), be included in the T&O revenue amount. He recommends that revenues associated with deliveries to the NYISO should be excluded because those deliveries are not likely to return to the Combined Region. Mr. Bustard also recommends that all revenues for non-firm T&O transmission service be included in the lost revenue amount with two adjustments. First, all revenues for non-firm transactions with a POD of the NYISO should be excluded. Second, the remaining revenues for non-firm T&O transmission service should be adjusted to account for the congestion component on revenue distribution under Section 27A of the PJM Open-access tariff, as identified by Mr. Dessender. AEP/Exelon IB at 19.

Dayton

77. Dayton states that its total T&O revenues for transmission service during calendar years 2002 and 2003 were $19.1 million and $31.3 million, respectively. Dayton notes that these revenues are based on the actual billing determinants and the actual, Commission-approved rates from Dayton's OASIS and do not include grandfathered transactions. Dayton further notes that these figures are not disputed or challenged. Therefore, Dayton contends that it is entitled to collect $37.7 million in SECA revenues during the transition period due to the elimination of T&O rates. Dayton IB at 11-13; Dayton RB at 10-11.

Parties' Contentions

Arguments on the Midwest ISO TOs' Filing

78. FirstEnergy states that it supports the position presented in the Initial Brief of the Midwest ISO TOs, which addresses the T&O revenues of each TO. FirstEnergy further states that with regard to PJM, the testimony of Mr. Dessender identifies the lost RTOR revenues for the TOs in Classic PJM, which include FirstEnergy affiliates Jersey Central Power and Light (JCPL), Metropolitan Edison Company (MetEd) and Pennsylvania

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Electric Company (Penelec). Finally, FirstEnergy notes that its witness, Mr. Fuerst, described PJM's T&O transmission revenues. FirstEnergy IB at 8.

79. On the other hand, AEP/Exelon and BGE contend that the Midwest ISO TOs have not adequately supported their lost revenue claims. AEP/Exelon note, for example, that NIPSCo and ATSI, who were transmission providers (*i.e.*, not yet members of the RTO) during all of 2002 and for the first 9 months of 2003, and Ameren, who was a transmission provider during all of 2002 and 2003, provided no witnesses to support their lost revenue claims, which are based on T&O transmission service that they provided during all or portions of the historical periods. Further, AEP/Exelon note that although Mr. Heintz testified that the other Midwest TOs "provided" him with their 2002 and 2003 T&O transmission revenues during the period of each of the years the TOs were not in Midwest ISO, he testified that he never independently verified this information, nor did the TOs submit sworn testimony supporting the data that they provided to Mr. Heintz. Similarly, for those months of 2002 and 2003 when a TO was in the Midwest ISO, Mr. Heintz testified that revenues were derived from T&O transmission service under the Midwest ISO open-access tariff, but no sworn testimony from a Midwest ISO witness was presented by any Midwest ISO TO to support the lost revenue claim based on revenues derived from T&O transmission service provided by the Midwest ISO. AEP/Exelon IB at 19-32.

80. BGE notes that Mr. Heintz purposefully did not exclude transactions that left the Combined Region. BGE RB at 14.

81. In response to AEP/Exelon's contention that the Midwest ISO TOs did not adequately support their lost revenue claim, the Midwest ISO TOs note that they submitted hundreds of pages of testimony, exhibits, and workpapers of Mr. Heintz providing the narrative description, calculations, and OATi tag data used in the development of the Midwest ISO TOs' lost revenues. Specifically, the Midwest ISO TOs note that each TO provided to Mr. Heintz its 2002 and 2003 T&O transmission revenues. Further, each TO provided a reconciliation of the amounts Mr. Heintz calculated as non-grandfathered T&O revenues and MWhs for the portion of the historical periods that each Midwest ISO TO was a transmission provider. Likewise, the Midwest ISO provided to Mr. Heintz the T&O revenues received and distributed to the Midwest ISO TO for the portion of the test periods in which the Midwest ISO was the transmission provider. The Midwest ISO TOs further note that Mr. Heintz analyzed the data to calculate the Midwest ISO TOs' lost revenues. The MISO TOs contend that since their witness, Mr. Heintz, supports through his sworn testimony the calculation and the resulting amount of the Midwest ISO TOs' lost revenues, no other witnesses are necessary to support their lost revenues. Finally, the Midwest ISO TOs state that they satisfied their burden to support their lost revenues and that if AEP/Exelon believe otherwise, that they should have provided evidence to the contrary. Midwest ISO TOs RB at 16-24.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Arguments on New PJM Companies Filing

82. AMP-Ohio, the Midwest ISO TOs and Quest contend that the level of lost revenues claimed by the New PJM Companies[41] are inflated and are in violation of the Commission's orders in this proceeding. There are three reasons proffered as to why the New PJM Companies inflated their level of lost revenues. First, they include revenues for In-Out transactions that sank outside the Combined Region.[42] Second, they include revenues for transactions for TOs that were not yet members of either the Midwest ISO or PJM. Third, they include revenues for transactions which they were not entitled to recover under PJM's open-access tariff. AMP-Ohio IB at 30-33; Midwest ISO TOs IB at 15-43; Midwest ISO TOs RB at 16-24; Quest IB at 22-34.

83. The first reason involves In-Out transactions, which are transactions that originate in AEP, ComEd, Dayton, or Dominion, have a point of delivery either in PJM or the Midwest ISO, but ultimately sink outside the Combined Region. The Midwest ISO TOs argue that In-Out revenues are not legitimate components of recoverable lost revenues. Further, the Midwest ISO TOs note that the Commission expressly stated that the lost revenues to be recovered pursuant to the SECA mechanism relate to the elimination of the RTORs. Midwest ISO TOs RB at 16-24.

84. Similarly, AMP-Ohio submits that no recovery at all is appropriate because RTORs were not eliminated for sinks outside the Combined Region.[43] Further, AMP-Ohio

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[41] The PJM TOs include AEC, AEP, ComEd, Dayton Allegheny Power, Dominion, Duquesne, BGE, FE (on behalf of its operating company affiliates), PECO, the PHI Operating Companies, PPL Electric Utilities Corp, Public Service Electric and Gas Company, Rockland Electric Company, and UGI Utilities, Inc. The Classic PJM or pre-expansion PJM excludes those entities joining PJM after Allegheny Power (Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company do business as Allegheny Power). Allegheny Power became a member of PJM on April 1, 2002. Commonwealth Edison Company and Commonwealth Edison Company of Indiana, Inc. (ComEd) joined PJM on May 1, 2004. AEP (on behalf of certain operating companies) and Dayton Power & Light joined PJM on October 1, 2004. Duquesne became a member of PJM on January 1, 2005 and Dominion on May 1, 2005. AEP, ComEd, Dayton, Dominion and Duquesne are commonly referred to as the New PJM Companies. AEC-SMECO IB at 2-3 n. 2 and 3.

[42] "Combined Region" refers to the footprint of Midwest ISO and PJM, combined with the footprint of the former Alliance Companies. *See* November 17 Order at P 3 and n.30.

[43] In the alternative, AMP-Ohio offers a compromise position. As the starting point for the compromise position, all corrections supported by the record should be made. Then, because there is absolutely no support for the significant difference between

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

contends that the New PJM Companies did not support their proposed level of lost revenues. For example, AMP-Ohio notes that PJM's witness, Mr. Dessender, merely assumed that any transmission to the PJM border created recoverable lost revenue, but did not confirm or evaluate the "ultimate sinks" associated with such transactions. AMP-Ohio IB at 31. Furthermore, AMP-Ohio notes that Dr. Henderson's defense of his proposed lost revenues is ineffective and unconvincing because he had to base "estimated zonal benefits" on a load-share ratio, since benefits could not be traced to load within the Combined Region. *Id.* at 32.

85. BGE also notes that the AEP/Exelon proposal includes "reverse hubbing," which is an "Out-In" transaction. BGE contends that reverse hubbing is detrimental to ratepayers and is not in compliance with the Commission's orders. *Id.* at 18-19.

86. According to AEP/Exelon, the elimination of rate pancaking has resulted in the loss of revenue for TOs within the expanded PJM for those legs of a transaction that are internal to the expanded PJM where the transaction ultimately sinks outside the RTO. AEP/Exelon argues that it is indisputable that the transmission fee has been lost and therefore In-Out revenues are a legitimate component of the lost revenue claims of AEP, ComEd, PECO, Dayton and Dominion. AEP/Exelon IB at 31-32.

87. With respect to the second reason why the New PJM Companies' lost revenues are overstated, Quest notes that during the historical periods of 2002 and 2003, AEP, ComEd, and Dayton were not part of PJM, and therefore imposed separate, "pancaked" transmission charges on power transactions that crossed each TO before going across the PJM/MISO border. Quest further notes that these TOs joined PJM before the elimination of the RTOR on December 1, 2004. Thus, immediately prior to December 1, 2004, there was only one single charge for exiting PJM regardless of how many PJM TO areas were crossed before going across the PJM/MISO border. Quest contends that only one single RTOR was eliminated. Therefore, Quest contends that lost revenues of the TOs should reflect only the single PJM border charge that was eliminated, not the pancaked charges that were in effect during the test periods. Quest IB at 34. Further, Quest argues that disputes over the inclusion of lost revenues based on intra-PJM transactions would be eliminated because relevant PJM entities would already have been integrated into PJM.

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the figures for 2002 and 2003, the 2002 figures should be reduced to the 2003 level. Finally, AMP-Ohio proposes a further reduction of 20 percent, a number that is no less supported than the lost revenues but that reflects a modest reduction to account for the likelihood that other redirections and points of delivery outside of the Combined Region exist. AMP-Ohio IB at 7. No party agreed to AMP-Ohio's compromise in its reply brief. Based on the discussion below, it is found that more reasonable alternatives were offered. As a result, AMP-Ohio's suggestion is rejected.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Id. at 19-20.

88. In response, AEP/Exelon note that the Commission in its Order on Clarification stated that intra-PJM lost revenues may be recovered in this proceeding. Midwest ISO, 109 FERC ¶ 61,243 at P 9 (2004) (November 30 Order). AEP/Exelon further argue that the timing of when various companies joined PJM cannot be considered a legitimate determinant of whether revenues have been lost as a result of the Commission's orders in this proceeding. AEP/Exelon RB at 11-24.

89. AEP/Exelon also state that there is inconsistent treatment of TOs within the two RTOs. For example, AEP/Exelon note that the MISO TOs have not excluded revenues associated with the initial legs of a T&O transaction that was internal to the expanded Midwest ISO where the transaction sank within PJM (*e.g.*, Midwest ISO-Ameren-FE-PJM). However, AEP/Exelon states that Quest's position is that AEP should not be permitted to include the same type of revenues associated with T&O transmission provided over its system to another PJM zone where the transaction was delivered to MISO. AEP/Exelon RB at 11-24.

90. The third reason for the overstatement of the New PJM Companies' lost revenue claim has to do with the terms and conditions of PJM's open-access tariff. PJM's open-access tariff does not distinguish between a "POD" and a "sink" when determining whether the RTOR will apply. AEP/Exelon RB at 15. Further, as Mr. Dessender testified, PJM has never based T&O charges on where the energy to be delivered ultimately sinks, and PJM does not currently assess a RTOR to reservations with a POD of MISO, regardless of where the energy to be delivered ultimately sinks. Thus, the New PJM Companies, under Schedules 7 and 8 of the PJM open-access tariff, did not collect revenues for transmission service provided through or out of their systems if the POD is MISO, regardless of the sink. AEP/Exelon note that if such revenues are not included as lost revenues, the New PJM Companies would lose revenues which they would have no ability to recover. Furthermore, AEP/Exelon contends that even if PJM were able in the future to modify its systems in a manner that would permit it to charge a RTOR on transactions with a POD of MISO but a sink outside the Combined Region, there is no way for PJM to collect such charges on transactions that occurred since December 1, 2004. *Id.* at 11-24.

Arguments on Certain Classic PJM TOs Filing

91. The Certain Classic PJM TOs[44] support Dr. Henderson's T&O revenues of

[44] The Certain Classic PJM TOs include: Allegheny Power System Operating Companies, *i.e.*, Monongahela Power Company, Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power; PHI Operating Companies, i.e., Potomac Electric Power Company, Delmarva Power & Light Company,

$48,143,947 for calendar year 2002 for the pre-expansion TOs (including Allegheny Power), and T&O revenues of $18,662,327 for calendar year 2003. Certain Classic PJM TOs IB at 5-6. In their Initial Brief, the Certain Classic PJM TOs state although initially there were errors in the calculations of the lost revenues, they are unaware of any unresolved issues relating to the calculation of their lost revenue claims. *Id.* at 5.

92. The optimism of the Certain Classic PJM TOs was misplaced. AMP-Ohio, AEP/Exelon and Quest raised serious issues in their briefs about the level of T&O revenues for the pre-expansion PJM TOs. For example, they note that the Certain Classic PJM TOs did not sponsor a credible witness to support either the TOs' or the RTO's T&O revenues. In addition, they note that there is no reasonable explanation as to why the lost revenues for 2002 are so much greater than the revenues for 2003. AEP/Exelon IB at 19-32; AMP-Ohio IB at 25-26; Quest IB at 32-34.

93. AEP/Exelon and AMP-Ohio claim that the witness for Certain Classic PJM TOs, Mr. Dessender, did not support his lost revenue claims. Rather, they note that his task was simply to quantify the amount of RTOR revenues during 2002 and 2003. Further, when asked under cross-examination, Mr. Dessender testified that he did not know what revenues the PJM TOs included in "the lost revenue calculation" and that he did not even know how "lost revenues" are defined. AMP-Ohio RB at 10 citing Tr. 751:19:24; 757:20-21.

94. AMP-Ohio avers that not only did Certain Classic PJM TOs not support their claim for lost revenues, they didn't even try to support them. AMP-Ohio claims that the pre-expansion PJM TOs, T&O revenue calculations are the "regulatory equivalent of three-card monte, in which . . . the person responsible for the numbers -- can never be found." AMP-Ohio IB at 24. Accordingly, AMP-Ohio contends that it would be fair and lawful to simply deny any SECA recovery to the PJM TOs (with the exception of PECO). AMP-Ohio IB at 29.

95. In response, FirstEnergy notes that the level of the pre-expansion PJM TOs' lost RTOR revenues are well-supported and easy to follow. FirstEnergy RB at 7-8. For example, Mr. Dessender, testified to the amount of RTOR revenues received by PJM during the historical period for both firm and non-firm transmission service for T&O transactions that did not have a point of delivery in NYISO. In addition, Mr. Fuerst and Dr. Henderson, the witnesses for FirstEnergy and PECO, testified that the amounts described in Mr. Dessender's testimony and the corresponding MWhs were the proper way to determine PJM's T&O revenues, *i.e.*, the amount of T&O revenue PJM received

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and Atlantic City Electric Company, Baltimore Gas and Electric Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; Rockland Electric Company; and UGI Utilities, Inc.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

in the historical test period. Thus, FirstEnergy argues that the claims that the pre-expansion PJM TOs' lost RTOR revenues are not supported and should be rejected. Id at 7-10.

96. Another issue has to do with the discrepancy between the T&O revenues for PJM for 2002 of $48 million and the T&O revenues, as adjusted, of $18.5 million for 2003. AMP-Ohio and Quest suggest that there may need to be a further adjustment to the proposed lost revenues, once a reasonable explanation of the discrepancy is provided. AEP/Exelon state that mere suppositions do not suffice, particularly in light of the fact that after extensive discovery by numerous active litigants, no one has identified any corrections other than the one made by Dr. Henderson. AEP/Exelon RB at 11-13.

Discussion/Findings/Conclusions

History of the Elimination of RTORs

97. The first part of the background analysis on the appropriate level of lost revenues deals with the reasons underlying the elimination of the RTORs. RTORs were eliminated because of the Commission's concern over the former Alliance Companies' RTO choices.[45] The Commission noted some of the former Alliance Companies, including the New PJM Companies, were "located in the heart of the Midwest ISO region and had close links with their neighboring utilities in the Midwest ISO." July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at 30. In addition, the Commission noted that "by virtue of their location and ties to their neighbors, the former Alliance Companies, through their failure to join RTOs, and also through their proposed RTO choices, [would] create a barrier that [would] obstruct more efficient and competitive electricity markets and the realization of adequate RTO scope and configuration in the region, thereby denying the benefits of more efficient and competitive regional electricity markets to customers in 21 states and one Canadian province. *Id.* at P 32. By way of example, the Commission found that accepting the former Alliance Companies' RTO choices unconditionally would result in fewer benefits from one-stop shopping or the elimination of rate pancaking than if AEP joined the Midwest ISO. *See id.* at P 33 (internal citation omitted).

98. Further, the Commission found that "other market participants would be adversely

[45] For a history of the proposed Alliance RTO, *see Alliance Companies, et al.*, 89 FERC 61,298 (1999) (Alliance I Order), order on reh'g and compliance, 91 FERC 61,152 (2000) (Alliance II Order), 94 FERC 61,070 (2001) (Alliance III Order), *order denying reh'g and providing clarification*, 95 FERC 61,182 (2001) (Alliance IV Order), 96 FERC ¶ 61,052 (2001) (Alliance V Order), and *order on requests for reg'h*, 97 FERC ¶ 61,327 (2001) (Alliance VI Order). The original Alliance Companies were AEP, Consumers Energy Company (Consumers), Detroit Edison Company (Detroit Edison), FirstEnergy, and Virginia Electric and Power Company (now Dominion).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

affected by continued rate pancaking across the proposed seam, effects that would have been eliminated had certain of the former Alliance Companies joined Midwest ISO instead of PJM." *Id.* Thus, the Commission noted that the RTO choices of the former Alliance Companies would: "(1) exacerbate rate pancaking across the proposed seam for transactions sinking within the RTOs, thereby obstructing more efficient and competitive electricity markets in the region; (2) violate the fundamental requirement of Order No. 2000 that RTOs eliminate rate pancaking over a region of appropriate scope and configuration; and (3) result in unjust, unreasonable, unduly discriminatory or preferential RTO rates." *Id.* at P 35.

99. Accordingly, the Commission found that "given Order No. 2000's requirement that RTOs eliminate rate pancaking over a region of appropriate scope and configuration, rate pancaking across the proposed seam of the New PJM Companies is incorrectly characterized as "inter-RTO" rate pancaking; rather, it constitutes "intra-RTO" rate pancaking which is unequivocally prohibited under Order No. 2000." *Id.* Therefore, the Commission eliminated the T&O rates that constituted both rate pancaking and "the seam." *Id.*[46]

Conflicting Goals

100. The next part of the background analysis for the appropriate level of lost revenues addresses the specific but often conflicting goals which the Commission has advanced over the course of this lengthy proceeding. One goal was the parties' concerns over cost shifting as a result of the elimination of RTORs. To minimize cost shifting among parties, the Commission allowed a "lost revenue recovery mechanism." November 17 Order, 105 FERC ¶ 61,212 at P 42. This mechanism eventually became known as the SECA.

101. A second goal was to hold utilities "revenue neutral." Under this goal, utilities would earn the same revenue under the SECAs as they would have earned under the to-be-eliminated through and out rates. The Commission explained that SECAs were not intended to provide greater revenues. *Id.* at 20.

102. A third goal was to recognize that with the elimination of RTORs there could be load growth. Such load growth would be supplied by increased imports from the other side of the seam. The Commission reasoned that even though companies may have increased revenues from load growth, they could incur increased transmission costs to

[46] The Commission initiated a Section 206 proceeding under Docket EL03-212-000 for the T&O rates of the former Alliance Companies, finding that the T&O rates under the tariffs of Ameren, AEP, ComEd, FirstEnergy, Illinois Power, NIPSCO and Dayton may be unjust, unreasonable and unduly discriminatory or preferential. July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 41.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

support the additional trading in the region. Nevertheless, the Commission noted that the "effect of [such] load growth on [a] SECA is typical for stated rates that are routinely accepted by the Commission." *Id.* at P 50.

103. A fourth goal of the Commission was to recognize the administrative savings associated with the integration of ComEd, AEP and Dayton into PJM. In fact, the Report on Going Forward Principles stated that PJM's rates would be adjusted to reflect the administrative savings associated with their integration. *Midwest Indep. Sys. Operator Inc.*, 106 FERC ¶ 63,024 at P 9 (2004) (Report on Going Forward Principles). The Commission approved this concept in the Order Approving the Going Forward Principles made to implement the rate changes. Order Establishing Going Forward Principles, 106 FERC ¶ 61,262.[47]

104. A fifth goal was to minimize the level of lost revenues. To address this goal, the Commission directed that lost revenues are to be recovered pursuant to a SECA mechanism would be for new transactions serving load within the other RTO during the transition period and for transmission service taken under the open-access tariff of the other RTO. *See* November 18 Order, 109 FERC ¶ 61,168 at P 66. Thus, the Commission did not eliminate RTORs for existing transactions sinking in the Combined Region or those existing prior to April 1, 2004. November 17 Order at P 14-15.

105. In an order issued concurrently with the November 17 Order, the Commission eliminated the T&O rates under the open-access tariffs of AEP, Ameren, ComEd, Illinois Power and Dayton effective April 1, 2004, for transactions sinking within the Combined Region. *Ameren*, 105 FERC ¶ 61,216. A revenue recovery mechanism for these companies was established to follow the SECA methodology described in the November 17 order. *Id.* at P 59.

106. Subsequently, the Commission noted that the level of lost revenues from the November 17 Order and the *Ameren* Order, would be reduced from $325 million/year to approximately $215 million/year by only allowing lost revenues associated with inter-RTO transactions. November 18 Order, 109 FERC ¶ 61,168 at P 61 n.41.

Order on Clarification

107. The third part of the background analysis for determining the appropriate level of lost revenues concerns the November 30, 2004 Order on Clarification. *See* November 30 Order, 109 FERC ¶ 61,243. On November 23, 2004, AEP filed an emergency motion for clarification of the November 18 Order. Specifically, AEP was concerned about the

[47] The Order Establishing Going Forward Principles states that the T&O revenues would be eliminated December 1, 2004 without any further transitional lost revenue mechanism. Order Establishing Going Forward Principles, 106 FERC ¶ 61,262 at P 23.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

language in footnote 41. AEP argued in its request for clarification that if the compliance filings had been made in March or April, 2004, as originally intended, SECA rates to recover lost revenues between the New PJM Companies and the pre-expansion PJM TOs would have been included in the filings. AEP stated that if intra-PJM SECAs are not allowed, it would lose approximately $35 million, and would be in a worse position than it would have been if it had delayed its entry into PJM until after December 1, 2004. On November 30, 2004, several parties filed timely answers to AEP's motion.

108. On November 30, 2004, the same day that answers to the motion were due, the Commission issued an order granting AEP's request for clarification. The Commission stated:

> We clarify that AEP, ComEd and Dayton may recover lost revenues associated with the elimination of intra-RTO rate pancaking through the SECA transition methodology in Docket No. EL04-135-000. AEP, ComEd and Dayton are in a different position than other transmission owners because they were integrated into PJM in the midst of the inter-RTO rate proceedings and have not had an opportunity to fully recover their lost revenues associated with the elimination of intra-RTO rate pancaking. Therefore, we will permit AEP, ComEd and Dayton to make appropriate filings for recovery of lost revenues associated with the elimination of intra-RTO rate pancaking through March 31, 2006 through the SECA transition methodology.

Id. at 9 (footnote omitted).

109. In the November 30 Order on Clarification, the Commission noted that "the arguments raised in [these] answers speak to the merits of the Commission's November 18 Order, and are therefore more properly raised in requests for rehearing of the November 18 Order. *Id.* at n.8. Furthermore, the Commission stated that with respect to any filings that may be made, parties will have an opportunity to respond to those filings. *Id.*

110. On December 6, 2004, a joint, expedited request for rehearing of the November 18, 2004 Order was filed by PJM and MISO members, customers and consumer representatives. The motion raised due process and procedural concerns. In addition, the motion asserted that there was no record support for AEP's claimed lost revenues of $35 million. Further, the motion asserted that by granting AEP's motion, the Commission increased SECA revenues by $110 million. On December 30, 2004, additional requests for rehearing of the November 18 Order were filed; those requests are still pending before the Commission.

111. The procedural history of this case along with the Commission's specific goals for establishing a SECA provide the background for evaluating the evidentiary record. The purpose of this hearing was to determine whether the compliance filings comport with the

Commission's directives in these proceedings and result in a SECA mechanism which is just and reasonable and not unduly discriminatory.

112. Since the Commission has not addressed the rehearing requests, there is ambiguity and uncertainty in the Commission's change of position from its July 23 Order, the November 17 Order and the *Ameren* Order, and its position in the November 30 Order. In the earlier orders, the Commission found that the former Alliance Companies' RTO choices constituted rate pancaking, were in violation of Order No. 2000, and were unjust and unreasonable. Later, however, the Commission found that the same entities "are in a different position because they were integrated into PJM in the midst of inter-RTO rate proceedings" and "have not had the opportunity to fully recover their lost revenues associated with the elimination of intra-RTO rate pancaking." November 18 Order, 109 FERC ¶ 61,243 at P 9. Given that the issue of whether and to what extent the New PJM Companies' lost revenues would be included in the calculation of the SECA is a fundamental aspect of this case a finding on the merits of this issue must be made.

Support for Lost Revenue Claims

113. A number of parties raised issues in their briefs about the lack of support for the level of T&O revenues during the base periods. This issue will be addressed by analyzing the quality of the testimony of those witnesses sponsoring claims for T&O revenues, which are used as the basis for calculating the SECA.

114. Mr. Heintz presented detailed testimony and exhibits on behalf of his clients, the Midwest ISO TOs. Under cross-examination, he showed his thorough knowledge of the case, explained his careful coordination of his presentation with Dr. Henderson's presentation, and was easily able to discuss the differences between the SECA methodology he proposed in the prior hearing in this case, which became the basis for the Commission's adoption of a SECA as a transitional mechanism, and the SECA mechanism he was sponsoring at this hearing.

115. However, there were flaws in Mr. Heintz' testimony. One flaw involved properly labeling the raw data contained in his exhibits. Although this flaw was corrected on the stand, it demonstrated that known and measurable changes were not taken into account when developing the lost revenues from the historical data. Another flaw was that Mr. Heintz did not independently verify the T&O revenue amounts provided to him by either the TOs or the Midwest ISO, nor did he request that they be independently authenticated. Ex. MTO 1 at 25:1-10. Further, he noted, "[N]ow it is almost impossible to calculate the transmission charges paid to other transmission owners because of the increased number of transactions.…" Ex. MTO-1 at 23:21-22.

116. Mr. Heintz' testimony does not lay a proper foundation as to the level of RTORs from which the level of lost revenues for the Midwest ISO TOs is derived. Further, it is

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

based on hearsay. Therefore, it is found that the level of T&O revenues, and thus, the level of lost revenues for the Midwest ISO is unacceptable.

117. Mr. Bustard, a witness for Exelon, testified as to the historical T&O transmission revenues of ComEd. Ex. EXE-1 at 3. He stated that he summed up all of the ComEd reservations that had a POD in the Combined Region. *Id.* at 5. He further stated that T&O transmission revenues were calculated based on the actual billing determinants and actual rates from ComEd's OASIS. *Id.* He reviewed internal billing data and OASIS reservation data to ensure that the results match ComEd's actual revenues. He also excluded all grandfathered transactions from his analysis. *Id.* at 6. His exhibits show his computations. Ex. EXE-2, Ex. EXE-3. Finally, Mr. Bustard stated that he provided his calculations to Dr. Henderson, who would develop the SECA. Ex. EXE-1 at 7. Mr. Bustard's testimony and exhibits adequately support ComEd's T&O revenue claims. However, his testimony does not adequately address known and measurable adjustments to the T&O revenues to develop lost revenues. Therefore, ComEd's lost revenues are not in compliance with the Commission's orders and are rejected.

118. Mr. Dessender, a witness for Certain Classic PJM Companies, testified that he quantified the actual RTOR revenues that all PJM Classic TOs received during calendar years 2002 and 2003 using PJM's actual billing records. Ex. CTO-1 at 2 and 6. Mr. Dessender excluded RTOR revenues for transactions to the NYISO. *Id.* at 4. In addition, he excluded revenues for grandfathered service. *Id.* at 6. This information was then provided to Dr. Henderson for use in determining the lost revenues for all of PJM. On cross-examination, Dr. Henderson testified he was not sponsoring the lost revenues for the Classic PJM Transmission Owners, but rather Mr. Bustard was. Tr. at 1108:6-1109:5. However, Mr. Bustard explained that "PJM actually did the calculation" of T&O revenues that should be used in calculating the lost revenue that's associated with those PJM Classic Companies." Tr. at 1382:18-23. No witness has supported PJM's lost revenues. Therefore, it is found that the Classic PJM Companies' lost revenues are rejected. It is further found that since the Classic PJM Companies failed to support known and measurable changes to the T&O revenues to develop lost revenues, the level of lost revenues is unaceptable.

119. Mr. Dessender also testified on behalf of PECO. He provided the dollar amounts and associated MWhs for both firm and non-firm T&O transactions. He used actual billing records for 2002-2003. Ex. PJM-2. He excluded firm transactions with a point of delivery in the NYISO. Ex. EXE-10 (Corrected). Mr. Dessender adequately provided the raw data supporting T&O revenues for PECO. He did not, however, support the level of lost revenues or SECA revenues. Dr. Henderson testified that he was not sponsoring PECO's lost revenues. Tr. 1108:24-1109:8. Further, contrary to AEP/Exelon's assertions, Mr. Bustard's testimony did not support PECO's lost revenue claims. AEP/Exelon IB at 14. Therefore, since no witness has supported PECO's lost revenues

claim, it is found that PECO's lost revenues are not supported by the record and that the compliance filing is rejected.

120. AEP's witness, Mr. Bethel, supported AEP's historical revenues based on the T&O transmission service revenues for the 2002 and 2003 calendar years, which were used as inputs to Dr. Henderson's SECA analysis. In addition, Mr. Bethel supported his proposed lost revenues with detailed exhibits Exhibit AEP-1 at 9-12; Exhibits AEP 2-6, 8A, Ex. S-3 at 4. Furthermore, on the stand, Mr. Bethel was a very credible witness, showing a thorough business, operational and financial understanding of both AEP and the energy industry throughout the Combined Region. Although, as discussed *infra*, some of AEP's proposed lost revenues are found to be inflated or not appropriate for including as lost revenues, Mr. Bethel's methodology for developing T&O revenues and lost revenues is sufficiently supported. The level of revenues, however, will have to be recomputed to conform to the findings of this Initial Decision.

121. Dayton's witness, Ms. Crawford calculated Dayton's T&O revenues of $19.1 million for 2002 and $31.3 million for 2003. Her calculations are based on the actual billing determinants and the actual, Commission-approved rates from Dayton's OASIS. Ms. Crawford confirmed the level of T&O revenues by reviewing internal billing data and OASIS reservation data to ensure that the results matched Dayton's actual transmission revenues. Further, Ms. Crawford excluded grandfather contracts by reviewing OATi tag data. Ex. DPL-1 at 4-7; Ex. DPL-2; and Ex. DPL-3 at 3-4; Ex. DPL-4. Ms. Crawford's T&O revenues were used by Dr. Henderson to compute the SECA.

122. Ms. Crawford's exhibits show how she computed Dayton's T&O revenues for the calendar years 2002 and 2003. However, Ms. Crawford did not support Dayton's lost revenues. Indeed, she stated that the 2002 and 2003 T&O revenues related to transactions within the Combined Region and are used as the revenue neutral target amount to be recovered by load throughout the Combined Regions. Ex. DPL-3 at 4. It is therefore found that Dayton's lost revenues are not supported by the record.

123. Dominion's T&O revenues for transmission service within the Combined Region for 2003 were $19,201,075.55. This amount was stipulated to in the Joint Stipulation of Facts. Ex. S-3 at 5. These revenues were provided to Dr. Henderson for computation of the SECA. Dominion did not support its lost revenues and therefore, its proposed lost revenue calculations are rejected.

124. Duquesne's T&O revenues were sponsored by Mr. Thomson. He derived the T&O revenues by determining the transmission service reservations granted through Duquesne's OASIS for transmission service in 2002 and 2003 for through and out service. He excluded all revenues for internal transmission service and grandfathered contracts. Mr. Thomson then multiplied Duquesne's open-access transmission rate for applicable T&O service to determine the amount of lost revenues. He then provided this

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

number to Dr. Henderson. Duquesne IB at 5. Mr. Thomson satisfactorily determined the level of T&O revenues for Duquesne. He did not, however, satisfactorily adjust those historical revenues to reflect known and measurable changes to develop lost revenues. Thus, the level of lost revenues for Duquesne is not accepted.

Revenues for In-Out Transactions

125. Another issue is the appropriate level of In-Out revenues for the New PJM Companies. In-Out transactions are transactions that originate in the service territory of AEP, ComEd, Dayton or Dominion, have a point of delivery either in PJM or in the Midwest ISO, and ultimately sink outside the Combined Region.[48] Most In-Out transactions were clearly identified in the testimony and exhibits. However, Mr. Heintz did not exclude the In-Out transactions he was able to identify. He stated, "I was not able to ensure that all of the MWhs associated with the reservations to those PODs actually left the Combined Region at that point and did not subsequently re-enter the Combined Region." Ex. MTO-1 at 14:5-7.

126. It is found that In-Out revenues are not a legitimate component of lost revenues. First, the Commission stated that lost revenues to be recovered pursuant to the SECA mechanism must relate to the elimination of the RTORs "for transactions to serve load *within the other RTO* where transmission service is taken under the open access transmission tariff of the other RTO." November 18 Order, 109 FERC ¶ 61,168 at P 66 (emphasis added). In addition, the Commission stated that "[a]s to the scope of the elimination of the RTORs, we will eliminate the RTORs for new transactions sinking in the [C]ombined [R]egion (*i.e.*, Midwest ISO, PJM, and the [former Alliance] Companies' footprints)." November 17 Order, 105 FERC ¶ 61,212 at P 14.

127. Further, the Commission stated that "the SECA is designed to recover all of the revenues lost due to the elimination of through and out rates on December 1, 2004." November 18 Order, 109 FERC ¶ 61,168 at P 61. Finally, even Dr. Henderson testified that only the PJM and Midwest ISO rates between themselves were to be eliminated. Tr. 1224:7-11. Therefore, contrary to some parties' contentions, the Commission did not require the elimination of RTORs for transactions that sank outside the Combined Region, nor did it allow for the collection of revenues associated with such transactions. November 18 Order, 109 FERC ¶ 61,168 at P 61, 66. It is found that inclusion of these transactions violates Commission orders. As a result, it is found that In-Out transactions must be eliminated from the lost revenue calculations.

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[48] In-Out revenues are distinct from intra-RTO revenues which were the topic of the November 30 Order.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Revenues for T&O Transactions by TOs (Intra-PJM Lost Revenues)

128. Another issue regarding the level of lost revenues has to do with rate pancaking. Rate pancaking occurs when power transactions cross one or more TO(s)' systems before going across the PJM/MISO border. With each border crossing, there is a separate transmission charge. As discussed earlier, the Commission was especially concerned about rate pancaking when some of the former Alliance Companies chose to join PJM rather than the Midwest ISO. Indeed, the Commission found that market participants would be adversely affected by continued rate pancaking across the proposed seam. The seam is not only non-contiguous, it is a classic example of gerrymandering. A map, showing the seam, is contained in Exhibit Nos. RTO 4-5, which is attached to this Initial Decision as an appendix. The Commission noted that the RTO choices of the former Alliance Companies would: (1) exacerbate rate pancaking across the proposed seam for transactions sinking within the RTOs, thereby obstructing more efficient and competitive electricity markets in the region; (2) violate the fundamental requirement of Order No. 2000 that RTOs eliminate rate pancaking over a region of appropriate scope and configuration; and (3) result in unjust, unreasonable, unduly discriminatory or preferential RTO rates. July 23 Order on Initial Decision, 104 FERC ¶61,105 at 35.

129. Furthermore, the Commission, on November 18, 2004, provided specific, detailed directives as to what the RTOs needed to file. The Commission stated:

> We direct Midwest ISO and PJM to submit revised tariff sheets by November 24, 2004, to implement the elimination of through and out rates, and adoption of the replacement rate design, effective December 1, 2004. These filings should: (1) reflect December 1, 2004, as the effective date for elimination of through and out rates[[49]] for reservations pursuant to requests made on or after November 17, 2003, for service commencing on or after April 1, 2004, *for transactions to serve load within the other RTO where transmission service is taken under the open access transmission tariff of the other RTO*; (2) reflect April 1, 2006 as the effective date for elimination of through and out rates *for all transactions to serve load within the other RTO where transmission service is taken under the open access transmission tariff of the other RTO*; and (3) incorporate the SECA

[49] We define the Midwest ISO through and out rate as the single, system-wide transmission rate in Schedules 7 and 8, and the Schedule 14 Regional Through and Out Rate. For PJM, the through and out rate is the single system-wide transmission rate for non-zone network load in section 34.1 and for delivery to the PJM border in Schedules 7 and 8, and the Transitional Revenue Neutrality Charge (TRNC).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

> mechanism as the transitional replacement rate effective December 1, 2004 through March 31, 2006.

November 18 Order, 109 FERC ¶ 61,168 at P 66 (emphasis added).

130. The above quote clearly shows that the Commission only intended that transmission service between the two RTOs, *i.e.*, between Midwest ISO and PJM, are to be included in the development of the SECA mechanism. As the footnote explains, only those TOs that take T&O service under the specific schedules in the Midwest ISO and PJM open-access tariffs could be charged a SECA. Clearly, revenues associated with a TO who did not take service under the defined RTO schedules (*i.e.*, Schedules 7, 8 and 14 of the MISO open-access tariff or Section 34.1 of the PJM open-access tariff) during the appropriate time frames could not be considered lost revenues.

131. As stated above, parties objected to the inclusion of intra-RTO lost revenues by AEP. They argued that this component shifts costs to the advantage of the New PJM Companies to the detriment of the Classic PJM Companies. AEP cites the November 30 Order to support its position. However, interpreting the Commission's orders in this proceeding (specifically, the *Ameren* Order, the November 18 and the November 30 Orders) and based on the evidence in this record, it is found that inclusion of the intra-RTO lost revenues is unjust and unreasonable. The *Ameren* Order, which eliminated the T&O revenues for a number of companies listed above, and created a SECA recovery mechanism for these revenues, specifically stated that it would not apply to companies that had joined an RTO. *Ameren*, 105 FERC ¶ 61,216 at P 34. AEP, joined the PJM RTO on October 1, 2004. Consequently, by the time the November 18, 2004 order was decided, AEP was in an RTO. Therefore, footnote 41 of the November 18 Order correctly states that the revenues to be considered in the proceeding were those dealing with inter RTO transactions. This item represents $35 million in revenues for AEP, but footnote 41 states that including only lost revenues for inter RTO transactions reduces the lost revenues by $110 million/year. November 30 Order, 109 FERC ¶ 61,168 at P 61 n.41.[50]

132. Since AEP, ComEd and Dayton joined PJM before the elimination of the RTOR on December 1, 2004, it is found that there was only a single charge for exiting either the Midwest ISO or PJM regardless of how many TOs' borders were crossed before going

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[50] It is noted that AEP received T&O revenues until it joined PJM. In addition, it received payments upon joining the RTO. For history fans, an excellent historical background and argument concerning these intra-RTO "lost revenues" is found in the December 6, 2004 Expedited Request for Rehearing filed by the PJM and MISO Regional Group (PJM and MISO members, customers and consumer representatives). Official notice is taken of this document.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

across the PJM/Midwest ISO border. Therefore, it is found that the level of lost revenues for either RTO should only reflect one border charge (*i.e.*, the border charge from the Midwest ISO to PJM or the border charge from PJM to the Midwest ISO), not the pancaked charges that were in effect during the test periods. Accordingly, AEP's SECA revenue calculations must be recalculated to exclude the intra PJM lost revenues.

PJM's Tariff Mechanism for Recovering Certain Types of Revenues

133. Another reason for the overstatement of the New PJM Companies' lost revenues has to do with the terms and conditions of PJM's open-access tariff. As noted earlier, under Schedules 7 and 8 of the PJM open-access tariff, PJM does not collect revenues for transmission service provided through or out of its network if the POD is MISO, regardless of the sink. According to AEP/Exelon, if these revenues are not included as lost revenues, the New PJM Companies would lose revenues which they would have no ability to recover them.

134. The Commission's orders were very clear that the ultimate sink should be the basis for charging the SECA. AEP/Exelon's argument that it has no way of recovering certain revenues because of the language in the PJM tariff is unpersuasive. First, as explained by Dr. Henderson, the revenues are lost because of how the PJM system works, not because of a Commission order. Tr. at 1216:13-22. Thus, the revenues would be lost regardless of whether the Commission eliminated T&O rates. Second, PJM and/or the New PJM Companies could have proposed tariff sheets to cover this scenario in a separate Section 205 filing. The time for proposing new rates for services not specifically provided for in the tariff is 60-120 days before the proposed rates are to take place. Given the unique circumstances of this case, PJM and/or the New PJM Companies could have even proposed the revised tariff sheets as part of their compliance filing in this proceeding. Regardless, imposing transmission charges for a service which the PJM open-access tariff does not contain, is prohibited by statute and the Commission's Regulations. Accordingly, it is found that the New PJM Companies may not include as lost revenues any revenues they were unable to collect due to the lack of provisions in the PJM open-access tariff.

Discrepancy Between 2002 and 2003 Lost Revenue Amounts

135. Another issue raised in briefs has to do with the discrepancy between the T&O revenues for PJM for 2002 of $48 million and the T&O revenues of $18.5 million for 2003. Some parties argue that this issue should have been raised during the discovery, pre-filed testimony or cross-examination process; not the briefing process. AEP/Exelon RB at 12. Regardless of where or how the issue should have been raised, there is still an unexplained discrepancy of almost $30 million. To be consistent with the finding in the "test period" section of this Initial Decision and to further the Commission's goal of

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

reducing lost revenues, it is found that 2003 revenues should be used as the basis for developing the level of lost revenues, and thus, the SECA.

Conflicting Goals

136. The final part of this analysis has to do with conflicting goals. A number of parties claim that "revenue neutral" means "guaranteed revenues." This is not so. "Revenue neutral" is interpreted to mean "revenue neutral, *ceteris paribus*." As discussed in the "test period" section of this Initial Decision, all other things did not remain the same between the historical periods and the transition periods. For example, in February 2002, the Midwest ISO started Day 1 operations, which means it began operating as an RTO; on April 1, 2002 Alleghany Power joined PJM; there was a major blackout in the Combined Region in August 2003; AEP, ComEd and Dayton integrated with PJM on October 1, 2004; Duquesne and Dominion joined PJM on January 1, 2005 and May 1, 2005, respectively; and on April 1, 2005, the Midwest ISO began Day-2 operations, which included a market-based mechanism for managing congestion.

137. Further, the Commission recognized quantifiable benefits of the New PJM Companies joining PJM, in Opinion No. 472 when it adopted the ALJ's extensive findings of fact. *New PJM Cos.*, 107 FERC ¶ 61,271 at P 52 (2004). These benefits included (1) $333 million in increased sales profits to AEP, (2) $149 million in reduced wholesale power costs to load during the 2005 calendar year, and (3) $300 million of annual production cost savings to PJM. *Id.* at P 48. Although there were cost offsets to these savings, the benefits remained significant. *Id.* Thus, with the magnitude of changes to the industry within the Combined Region, it would be extremely difficult, if not impossible, to determine what revenues were "lost" solely as a result of the elimination of RTORs. *See* Tr. at 2265:20-2267:13.

138. The Commission also has goals of recognizing increased costs as a result of load growth and recognizing administrative savings. Both Midwest ISO's and PJM's rates are cost-based. The theory of cost-based rates provides a utility a reasonable opportunity for the utility (or in this case, the TOs comprising the RTOs) to recover its cost of service or revenue requirement; it does not guarantee full recovery of the utility's revenue requirement. *See generally Fed. Power Comm'n et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

139. As the Commission stated in its November 17 Order, the revenue requirements of the TOs, which are cost based, are not at issue here. November 17 Order, 105 FERC ¶ 61,212 at 9. There is simply a shift from RTORs to a SECA. Further, for the SECA mechanism to be just and reasonable, it must be within a "zone of reasonableness." *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984).In addition, the SECA mechanism must be based on the costs of providing the service. The change from RTORs to the SECA mechanism should not allow overstated or inflated lost

revenues. *See generally Hope Bluefield Water Works and Improvement v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).

140. The final goal has to do with cost shifting. Although the issue of the appropriateness of the SECA was not set for hearing, arguments have been raised in this proceeding concerning its reasonableness. *See* BGE IB at 3-11, BGE RB at 5. The Commission may want to reconsider in its pending orders on rehearing whether the SECA mechanism is a just and reasonable method for dealing with cost shifting. As noted earlier, the SECA was intended as a transition mechanism for a limited period of time to reduce cost shifting and keep TOs revenue neutral as a result of the elimination of RTORs. The RTORs were eliminated primarily because of the decisions made by the former Alliance Companies which led to a gerrymandered border between the Midwest ISO and PJM. *See* Ex. RTO-4, 5 (attached as an appendix to this Initial Decision). The evidence in this case shows that the beneficiaries of the SECA are the Alliance members who decided to join PJM. Those that do not benefit are the other TOs in the Combined Region and their customers. Although the Commission strongly urged the TOs to join an RTO, it is those customers who are "penalized" by that decision in the form of a SECA. The admirable concept of minimizing transition costs and keeping TOs revenue neutral was lost during the costly litigation of this case.

141. The evidence in this case supports the following findings. Some TOs supported their 2002 and 2003 T&O revenues, others did not. Some included transactions which should have been excluded since they did not sink in the Combined Region. Others added transactions that did not sink in the Combined Region but "came back in." Additionally, others alleged they were entitled to lost intra-RTO revenues even after they had joined the RTO. Once they ascertained a 2002 and 2003 alleged T&O revenue number then all thinking stopped. Magically this number became the "lost revenues." The TOs did not adjust this "lost revenue" number for known and measurable changes. This cursory attempt and noncompliance with Commission orders must be rejected. As described below in the rate design section, there are additional reasons why these numbers are not acceptable and even after a hearing, the "lost revenues" are even more "lost."

Issue 2. Lost Revenues – Affiliate Issues

Parties' Contentions

142. FirstEnergy and Staff argue that inter-affiliate transactions should be included as part of the lost revenue calculations for SECA charges. FirstEnergy asserts that TOs included affiliate transactions in their lost revenue calculation in their compliance filings. FirstEnergy IB at 8-16; FirstEnergy RB at 11-14. Additionally, FirstEnergy argues that use of a corporate family theory to exclude these transactions would violate the Standards

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

of Conduct[51] and Commission policies on the treatment of affiliates,[52] which require that affiliates function separately. FirstEnergy IB at 10.

143. Staff asserts that much of the lost revenues claimed by the TOs can be attributed to transactions between affiliates. Staff IB at 8-22; Staff RB at 5-15. Staff defines affiliate transactions as those transactions involving transmission service reservation payments to a TO by its merchant affiliate. According to Staff, merchant affiliate transactions generally should be included in the calculation of a TOs' lost revenues. These revenues should only be excluded if their inclusion would lead to additional revenue recovery for the TO and its affiliates. Elimination of RTORs reduces the expense of transactions across transmission systems, and affiliate transactions are affected by this change. Thus, more than offsetting revenue and expense accounting entries must be included in the analysis of this subject. Staff postulates three conditions which must be met for the affiliate transactions to be included as lost revenues and concludes that the conditions have been met for most transactions included as lost revenues in this case.

144. Dominion,[53] Hoosier, BGE, AMP-Ohio and Quest oppose inclusion of affiliate transactions in the lost revenue calculations. Hoosier IB at 2-3; BGE IB at 28-30; RB at 20-21; AMP-Ohio IB at 30-31; RB at 17-25; Quest IB at 25-31; RB at 10-16. These parties maintain that in order for the SECA costs to be allocated in proportion to the benefits received, merchant affiliate transactions must be eliminated from the calculation of lost revenues used to determine the SECA charges. This is due to the fact that T&O transmission service revenues under the same corporate umbrella are not a net gain as a result of the underlying transmission reservations. Dominion IB at 9-13; Dominion RB at 5-17. The transaction really reflects the allocation of transmission costs and revenues on paper, there being no difference in the net outcome with respect to the corporate entity as a whole. Thus, if there is a loss of revenues for the transmission company due to the

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[51] Non-Discrimination Requirements, 18 C.F.R. § 358.5(c) (2005).

[52] FirstEnergy IB at 10 (citing Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Serv. by Pub. Util., Recovery of Stranded Costs by Pub. Util. and Transmitting Utilities; FERC Stats & Regs ¶ 31,036 (1996); order on reh'g, FERC Stats & Regs ¶ 61,248 (1997) (Order 888-A), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 86 FERC ¶ 61,048 (1998), aff'd and remanded sub nom Transmission Access Policy Study Group, v. FERC, 225 F.3d 667 (D.C. Cir. 2000)).

[53] Dominion filed a Motion to Strike portions of AEP/Exelon's Reply Brief. The Motion to Strike is denied. The record speaks for itself regarding Staff's proposals and appropriate consideration will be given to the arguments of all parties based on the record.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

elimination of the through and out rate, there is an equal and opposite cost saving to the merchant affiliate.

145. Dominion argues that there is no showing that merchant affiliate customers benefited from elimination of T&O rates and that without this showing, there is no basis to allocate SECA charges to the customers based on affiliate transactions. Additionally, Dominion argues that there is no evidence in this record that the market price charged by the merchant affiliate included a transmission component or the cost of this component. Dominion IB at 12.

146. It was a widespread practice during the test period, according to BGE, for RTOR payments made by an AEP company to go to another AEP company. BGE argues that since AEP has only one publicly traded stock, there was no net increase in income to the bottom line of AEP stockholders resulting from the affiliate transactions. Thus, allowing revenues from affiliates to be included in the SECA charges to be paid by third parties, provides a "windfall" to the corporate family, especially the "behemoth multi-state AEP complex of affiliate transmission companies." Quest IB at 22-34. BGE IB at 27-30. Parties also argue that the entire corporate family must be examined, not just the TO. This is because money is internally transferred from one affiliate to another with no impact on the corporation's total earnings. Quest IB at 22-34.

147. In addition, parties contend that allowing affiliate transactions will cause distortions in regional energy markets, as the extra payments will subsidize the generation affiliates of the companies collecting the SECA revenues. Hoosier IB at 2-3. These distortions in generation markets will reduce any benefits that LSEs like Hoosier might experience from elimination of RTORs. Additionally, allowing inter-affiliate revenues to be included in the SECA charges provides the generation subsidiaries an economic advantage over non-affiliated generators. Hoosier IB at 2-3; Quest IB at 22.

Discussion/Findings/Conclusions

148. In the compliance filings, the TOs included revenues they received from their affiliates as "lost revenues." FirstEnergy and Staff supported the inclusion of affiliate transactions in the lost revenues. On the other hand, AMP-Ohio, BGE, Hoosier, and Quest opposed the inclusion of revenues received from affiliates. The record shows that this issue is significant since at least half of AEP's lost revenues for SECAs involve inter affiliate transactions. Tr. at 1315:7-23.

149. The SECA was intended to hold utilities "revenue neutral," *i.e.*, to allow utilities the same revenue under the SECAs that they would have earned under the to-be-eliminated through and out rates. The SECAs were not intended to provide greater revenues." Order on Going Forward Principles, 106 FERC ¶ 61,262 at P20.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

150. Staff agrees that from a financial perspective or for accounting purposes, a TO records as revenue the payment for a RTOR made by a marketing affiliate and the affiliate would record as an expense the same amount to reflect the payment. It also agrees that the cash inflow to the corporate enterprise is substantively the same when you analyze it from the perspective of a payment made by a third party or an independent LSE, directly to the TO, or indirectly, through the marketing affiliate as an intermediary. Staff IB at 13-14.

151. Staff proposes three conditions that must be "conjunctively met for the transactions to be included as lost revenues: (1) an independent LSE is the ultimate source of the RTOR payment; (2) elimination of the RTOR causes the price to the merchant affiliate's LSE customer to fall; and (3) imposition of the SECA with respect to the affiliate transaction at issue is revenue neutral for all parties." *Id.* at 11. Thus, if the price to the LSE does not fall, the affiliate revenues should not be included in the lost revenue calculations.

152. Staff does not disagree with the fact that given the dynamics of energy pricing at the present time, the LSE's price will not necessarily fall (or not fall) in the same amount as the eliminated RTOR. Staff also agrees with the observation that in competitive bulk power markets, prices are not driven by fixed costs and rates which reflect recovery of fixed costs, but by the incremental costs of competitive suppliers and the marketplace demand for energy at a particular hour. *Id.* at 15.

153. Staff argues that its analysis is sound and that parties have not demonstrated that they met the test for exclusion of the affiliate revenues. Staff states, "[I]n general, there is likely to be a fall that would justify an inclusion of affiliate transactions in the calculation of the SECA charge." *Id.* Staff argues that elimination of the RTORs generally caused a downward pressure in energy pricing and if it is shown that the price of energy relevant to an affiliate transaction did not fall, all other factors being equal, that affiliate transaction should not be included in lost revenues. Thus, according to Staff, other factors may have prevented prices from dropping, or even caused an increase. However, Staff argues this does not negate the fact that elimination of the RTORs caused a downward pressure on prices, directly or indirectly. *Id.* at 17. Staff posits that the prices would have been even higher had the RTORs remained in effect. *Id.* at 9, n.11.

154. Staff's analysis is not supported by any underlying evidence[54] in this record and is based solely on theoretical assumptions that have been disputed by the testimony of Mr. Zakem. Mr. Zakem provided testimony concerning Staff's three-prong test. Mr. Zakem

[54] Staff supported its argument by stating that there was more efficient dispatch as a result of the elimination of RTORs. However, this argument does not support the inclusion of affiliate transactions as lost revenue for SECA charges.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

testified that Staff's first assumption is not borne by an understanding of market dynamics. Ex. QST-15 at 14:2-18:18. Mr. Zakem provided an example in response to the testimony of Staff witness, Mr. Pollock as discussed below. *Id.* at 15:14-18. Staff's second assumption is not correct. The record does not show that the price paid by the LSE included transmission equal to the amount "charged" the affiliate. As Mr. Zakem testified, T&O transmission rates paid by a merchant affiliate to its TO affiliate are not additive costs of the sale transaction. *Id.* at 12:1-5. Staff's third requirement is incorrect because the SECA would replace an internal cross-charge within AEP by money coming into AEP from external LSEs, which would result in a windfall for AEP. Consequently, Staff's witness' testimony is not given substantial weight and Staff's arguments are found unpersuasive.

155. Mr. Zakem's testimony has an example of market dynamics. To wit, a sale across the seam at $100 implies that the price for a comparable product sourced from within the buyer's RTO is at or above $100. This is the case because otherwise, the buyer would purchase the product at the cheaper, internal price. In addition, the price of power is not driven by the seller's costs – it is determined by what the seller can get for his product in the market. Ex. QST-15 at 9 and 20. While the RTOR was eliminated for power coming across the seam, the price for power within the RTO remains the same, telling the supplier across the seam that it still only needs to beat the price from within the RTO zone. The price the merchant affiliate is able to charge and make a margin does not change. In a well-run organization, it does not make a difference where--in which internal department--a margin is credited. The driving economic force is if the transaction is profitable to the entity as a whole. Thus, the price of $100 is viewed in the context of the cost to the total business entity-incremental revenue versus incremental cost. The internal-cross charge for transmission becomes irrelevant. Ex. QST-15 at 15:10-11. This testimony is entitled to significant weight.

156. Mr. Zakem testified that the evidence does not show that elimination of the RTOR resulted in lower power prices.[55] Ex. QST-15 at 8:4-11:14. A cursory look at market prices relevant to Quest/ESI shows no visible differences in prices before and after December 1, 2004 due to the elimination of the RTOR.[56] This is in keeping with what one would expect from an understanding of market dynamics.

157. Further, Mr. Zakem testified, that inclusion of inter-affiliate transactions creates a

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[55] Staff argued that Mr. Zakem's data is not meaningful since it is derived from a small sample. However, Mr. Zakem's testimony is the only quantified testimony on the record concerning this point and is given substantial weight.

[56] Exhibit No. QST-16 shows on-peak prices (day-ahead spot prices) for the Cinergy daily index and the North ECAR daily index, from mid-November through mid-December, excluding Thanksgiving.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

huge financial windfall for the TOs of approximately $243 million or 52 percent of the total SECA assessed by the TOs. Ex. QST-6, Ex. QST-11, Tr. 1773:7-11. Mr. Zakem gave an example of the merchant affiliate internal payment issue as it applies to Quest. AEP has a merchant affiliate within its integrated utility. That merchant affiliate pays the transmission affiliate for T&O service. Quest purchased power from AEP, and AEP delivered and paid its transmission affiliate for T&O service. Mr. Zakem contends and calculates that the entity, the AEP integrated utility, saw no gain or loss from that internal payment. When that internal payment stops, the SECA is being supplied by money that's coming from outside the corporation from Quest and other LSEs and is replacing the money that used to be paid internally within AEP, and therefore, AEP in total sees a net increase in money coming from outside the company due to the SECA. Tr. at 1771:6-16. Mr. Zakem's testimony will be given significant weight. [57]

158. Other parties also dispute Staff's assumptions. Staff assumes that the cost of transmission service is included in the price paid by the LSE to the merchant affiliate. [58] Dominion avers that Staff did not prove this critical assumption. Additionally, Dominion points out that the principle of comparability requires TOs to charge all entities, including itself and its affiliates, the open-access tariff rate for transmission service; it does not require the merchant affiliate to pass such charges to the LSE customer. Dominion RB at 12. In addition, according to Dominion, Staff incorrectly asserts that the transmission costs paid by the merchant affiliate are variable costs as to the affiliate (the costs as to the

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[57] This disputes Dr. Henderson's testimony. Dr. Henderson was asked the following hypothetical. Assume all of the RTOR was "paid" by the generator within the same corporate family as the TO. If the RTOR was eliminated and the SECAs were paid by load, would not the integrated utility receive an increase in revenues upon implementation of the SECA. Tr. at 1225:11-1226:7. Dr. Henderson stated that he did not think that was the integrated utility's position and went on to testify that the profit position of the affiliated generator would depend on delivered prices. *Id.* 1227:12-15. However, he did concede that the affiliated generator would have paid the RTOR and the load would pay the SECA during the transition period. *Id.* at1228:2-5. On redirect, Dr. Henderson made certain assumptions clarifying his response to the hypothetical. Dr. Henderson theorized that the delivered price paid by the LSE would include transmission plus the price of the power; therefore, load would have paid the RTOR and load would have paid the SECA. *Id.* at 1246:13-1247:5. Mr. Zakem was a more credible witness on this point. Additionally, Mr. Zakem testified that most of the savings from the elimination of the RTOR were likely captured by the merchants.

[58] Staff cites Dr. Henderson's testimony for the proposition that the load, as the ultimate customer, would have paid the price for transmission even though the affiliate generator served as the shipper. However, this testimony is not consistent with Mr. Zakem's testimony or the record concerning affiliate transactions and will not be given significant weight.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

TOs would be primarily fixed). Dominion avers that the merchant affiliate pays for transmission reservations and would be required to pay the fixed costs of the reservation regardless of how much power is shipped (reservations could last up to a year). Dominion asserts there is no evidence in this record to prove Staff's point and it is not known whether an affiliate used an existing reservation or a new reservation. Under Staff's test the market price must fall by the amount of the RTOR for the TO to be revenue neutral. There is no evidence in this record that this was the case. *Id.* at 13-14.

159. Further, Dominion agrees with Staff that from the perspective of overall corporate profits of a combined enterprise, the relevant drivers for a particular transaction are what the merchant affiliate's competitors are charging and whether the sale at a particular price will make an acceptable contribution to overhead, rather than the perceived need to recover a predetermined share of the transmission owner's fixed costs. According to Dominion, Staff recognized that any sale which exceeds variable costs, by definition, makes a contribution to overhead, and potentially to the profits of the overall enterprise. Dominion therefore avers that the central factors in the pricing and sale decision are (1) variable costs and (2) any forecast of potential opportunity costs associated with proceeding with a particular transaction. However, Dominion points out that even if the transmission costs paid by a merchant affiliate to its affiliated transmission owner were considered "variable" they would be offset by the corresponding "variable" transmission revenues received by the transmission owner, and there would be no need to include such cost in the price charged to the LSE in order for the corporate enterprise as a whole to make an acceptable contribution to overhead. *Id.* at P n.19, 20.

160. Dominion argues that there is no evidence that merchant affiliates did not operate with a goal of maximizing profits for the overall combined enterprise, in which case the costs of reservations made from the uncommitted transmission capacity of the enterprise would be regarded as sunk costs to the enterprise and would not enter into the calculation of a given transaction's contribution to margin.[59] These transactions would not meet the second prong of Staff's test, and would not be included in lost revenues. *Id.* at 11 n.23.

161. Additionally Dominion argues that Staff concludes that merchant affiliate transactions meet its test. However, there is no record support that the merchant affiliate revenues included in the companies' lost revenues satisfy the revenue neutrality requirement. As Dominion asserts, Staff includes the transmission expense paid by the merchant affiliate to the parent utility in its consideration of the overall profits of the combined enterprise, but ignores the offsetting transmission revenues received by the parent of the affiliate in its profit analysis. Dominion points out that if Staff had not

[59] Mr. Bethel testified for AEP that transmission reservations may be a "sunk" cost, such that once paid, there is an incentive to use the transmission whether the cost of transmission is recovered or not. Tr. at 1309:11-16.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

ignored these revenues, it would have realized that the merchant affiliate's payment to its parent corporation has no effect on the overall combined profits of the combined enterprise and is irrelevant to the consideration of the price charged an LSE. *Id.* at 14. As further analyzed by AMP-Ohio, Staff rejects the only quantified record evidence on price but excuses the TOs from proving this prong of Staff's test, since it argues that the TOs have demonstrated that affiliate transactions should be included. AMP-Ohio IB at 12.

162. According to Dominion, most sales by merchant affiliates were made at market-based rates or negotiated rates that did not necessarily include a transmission component.[60] In instances when a transmission component is identified, this does not necessarily reflect a determinant of market price but may reflect an after-the-fact allocation of a transmission component based on the preferences of the parties to the transaction. The record lacks evidence that a LSE paid a merchant affiliate for the costs of the RTORs; or that elimination of the RTORs resulted in a reduction in charges to the LSEs; or that imposition of the SECAs with respect to affiliate transactions results in revenue neutrality for all parties. Dominion asserts that the elements of the three-part test proposed by Staff have not been met and therefore, affiliate revenues must be excluded from the lost revenue calculations. Dominion IB at 19.

163. AMP-Ohio avers that where the seller of power is an affiliate, the seller may ignore some or all transmission costs in order to obtain a sale (profitable from the generation standpoint), because the cost of transmission is not truly an out-of-pocket cost to the integrated utility as a whole. The example below explains this well thought out argument.

> Suppose that when RTORs were in force Utility X and Utility Y were competing to supply a load in Utility Z, and Utility Z is interconnected to both X and Y. Utility X can earn a profit on its generation costs by selling the power for $10, but must also pay $2 to a non-affiliate for transmission to Z. In this example, Staff is correct that the price is likely to be no less than $12 and will include the transmission cost. Utility Y can earn an acceptable profit on its generation only by selling power for at least $11 (not $10), and it must pay a transmission charge of $2 to an affiliate. Utility Y can undercut Utility X's best price of $12, even though Y's cost of generation is higher, because it can reduce or eliminate the $2 "paid" to an affiliate from its price, thus selling for $11. Utility Y would still earn its desired profit, which shows that Staff's hypothesis that RTOR costs to affiliates were included in prices is not always correct, and in a competitive market rarely may be correct.

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[60] Mr. Bethel testified that rates are usually negotiated. Tr. at 1304:16-18.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

AMP-Ohio RB at 23 n.23.

164. In addition, AMP-Ohio disagrees with Staff's hypothesis that the cost of inter-affiliate RTORs were included in power prices and the elimination of RTORs would have reduced the price at which power was sold, necessitating additional, replacement revenues.

165. After due consideration of the parties' arguments and the record in this case, it is found that Staff's assumptions are not supported and Mr. Pollock's testimony is not entitled to significant weight. Furthermore, the testimony of Mr. Zakem is given significant weight due to the fact that this is the only evidence in this case which attempted to quantify the assumptions presented or the price paid by LSEs. Additionally, it is found that this evidence corroborates that Staff's test is not supported by the record evidence nor is it consistent with market dynamics. As a result, it is found that there is no record support for Staff's conclusions.

166. Furthermore, it is found that there is no record evidence of a transmission component being charged by AEP or any affiliate belonging to any party in this proceeding. Moreover, there is no evidence demonstrating that a transmission component was used to determine the market price paid by customers to justify including merchant affiliate revenues in the SECA charges paid by these customers. The record does not show that the costs to the merchant affiliate were substantiated. Consequently, it is found that the TOs did not prove Staff's second point or did not prove that elimination of the RTOR caused the price to the merchant affiliate's LSE customer to fall.

167. Additionally, it is found that Staff misplaces the burden of proof by assuming that affiliate transactions created revenues that should be included in the SECA obligations. The burden of proof should be on the proponents of the compliance filing to demonstrate that inter-affiliate transactions resulted in revenues that should be included as lost revenues in the calculation of the SECA charges. Staff does agree that transactions which result in additional revenue recovery for the TO and its affiliates should be excluded.[61] Staff IB 18-19 (citing July 23 Order on ID, 104 FERC ¶ 61,105 at P 17 (for the proposition the Commission intended to exclude such transactions from lost revenues)). This is exactly what the test should be: if transactions between affiliates did not result in net revenues, they should not be included as "lost revenues" in the calculation of SECA.

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[61] Staff cites with approval a relevant portion of the testimony of Mr. Solomon, the only other witness who attempted to submit evidence on this point. Staff IB at 18-19 (citing Ex. MTDU-40 at 5:18-17:8). Staff agreed with Mr. Solomon that the fixed-rate bundled services contract between Cinergy and Blue Ridge Power Authority (BRPA) would amount to double recovery for the TO and its affiliate.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

168. Staff argues that Dominion and Quest have not proved their points. However, Staff did not demonstrate its assertion that the price charged by the affiliate to the LSE decreased in correlation to the eliminated RTOR. Additionally, the inquiry really should be how the entire corporation reflected the affiliate transactions, not what the affiliate charged the LSE.

169. Staff's theoretical assumptions citing the Commission's assumptions are valid from the perspective of elimination of the RTORs *vis-a-vis* the market in general, not in the analysis of inter-affiliate transactions. As a matter of fact, the issue of affiliate revenues is not addressed by the Commission in any of its previous orders. Finally, Dominion is correct that this record does not show that the cost responsibility for recovery of merchant affiliate revenues through SECA obligations results in costs being allocated in proportion to the benefits received from the elimination of pancaked rates formerly charged to merchant affiliate transactions.

170. As for FirstEnergy, it argues that the proponents for removal of affiliate transactions are only responsible for paying PJM lost revenues.[62] This argument is meritless. Next, it argues that its affiliate (FirstEnergy Solutions is the affiliate of ATSI, a Midwest ISO TO) paid RTORs for Existing Transactions (ETs) citing to Exhibit No. S-3 at III.B.1.and thus did not save any expense from elimination of RTORs. As AMP-Ohio correctly points out, this would apply only to ETs; FirstEnergy must have had other types of transactions and not just ETs.

171. FirstEnergy argues that its affiliate, FirstEnergy Solutions, also an LSE paid SECA charges in the transition period for its usage in the test period. This argument does not support its contentions. Moreover, the Commission's comparability standards and requirements for separation of functions have no bearing on lost revenues for the imposition of SECA obligations contrary to FirstEnergy's arguments. *See* 18 C.F.R. §§358.5(c), (d) and 358.4(a)(1), (d).

172. Moreover, FirstEnergy's arguments are based on a number of incorrect assumptions. First, it argues that since the revenues recovered in 2002 and 2003 included inter-affiliate transactions, it was appropriate to include these revenues in the compliance filing. However, whether inter-affiliate transactions should be considered revenues for TOs to base SECA obligations on is an issue to be resolved in this proceeding.

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[62] AMP-Ohio sarcastically argues that consistent with all the interesting developments in this case, some TO's are cynically arguing in favor of recognition of a corporate family in order to recover payments from Green Mountain while at the same time arguing against recognition of the corporate family concerning this issue. AMP-Ohio RB at 17.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Additionally, FirstEnergy argues that the "recovery of the transmission owner's Commission–approved transmission revenue requirement is at issue in this case. FirstEnergy IB at 12 n.28. This is not correct; this case is not about the TOs' revenue requirements. As a matter of fact the Commission clearly stated this in its previous orders in this case. *See* November 17 Order, 105 FERC ¶ 61,212 at P 47, 49.

173. As AMP-Ohio correctly points out, the appropriate "transmission owner" for the purpose of measuring revenue neutrality is the parent, not the subsidiary; thus the replacement of an inter-affiliate RTOR (which produces no revenue for the integrated company) with a SECA charge to a third-party producing revenues, does not fulfill the requirement of revenue neutrality. Additionally, the record does not support the assertions made by FirstEnergy that native load customers will pay increased rates if affiliate transactions are not included in lost revenues.[63] Again, as asserted by AMP-Ohio, the Commission did not establish any mechanisms to impose transmission rate increases on native load customers if the SECA proponents calculated their revenues incorrectly.[64]

174. Although AEP/Exelon agree with Staff's conclusions that it has not been shown that affiliated transaction revenues should be excluded from the lost revenue claims, they argue that the test proposed by Staff should not be adopted. AEP RB at 23. AEP agrees that the behavior of delivered prices will be determined in the marketplace by marginal costs and the marginal costs of most transactions will include any transaction-specific transmission charges but does not provide any specific evidence of the market once RTORs were eliminated. *Id.* at 20.

175. AEP/Exelon criticize Mr. Zakem's study as being cursory and not evidence about the behavior of delivered prices in response to the elimination of T&O rates. However,

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[63] It is noted that T&O revenues result in credits against the TOs revenue requirements and thus reduce costs borne by native customers. November 17 Order, 105 FERC ¶ 61,212 at P 19 n.36. However, this record shows this does not refer to affiliate transactions.

[64] Although FirstEnergy believes that revenues between affiliates should be included it contends that if the Commission were to require their exclusion from lost RTOR revenues, it also must determine that no affiliate of a TO is responsible for paying a SECA obligation associated with T&O transmission service provided during the test period by its affiliated TO. As discussed above, it is not unjust, unreasonable, and unduly discriminatory to exclude affiliate transactions from the lost revenue calculations. Moreover, FirstEnergy has not supported its assertion for adjustments based on the exclusion of these transactions. Accordingly, its request is rejected.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

AEP did not offer any studies to contradict those of Mr. Zakem. Instead, AEP/Exelon cite Dr. Henderson's rebuttal testimony for the proposition that the standard for lost revenue recovery has always been lost transmission revenues, not lost corporate profits. However, Dr. Henderson was not qualified as a legal expert and thus, his assertions concerning affiliate revenues are not given significant weight. Dr. Henderson speculated that the elimination of affiliate transactions would discriminate against affiliated generators *vis-a-vis* independent generators. He postulated that if affiliate transactions are removed from the alleged lost revenues, the affiliated generator would be required to provide an offset to the lost transmission revenues of the utility's transmission function, which would be the financial equivalent of imposing a transition charge on the utility's generation function. Ex. PTO-81 at 71-72. This testimony is not supported by the record and not entitled to significant weight based on the findings concerning this issue.

176. AEP asserts that the T&O revenues from affiliated transactions traditionally have been a significant factor in lowering transmission rates since approximately one-half of the point-to-point revenues credited against cost of service in the last rate case were affiliate transactions. Tr. at 1315:18-23. However, as noted earlier, this case does not involve AEP's revenue requirements or transmission rate. Therefore, this testimony will not be given significant weight. This case does not involve the development of AEP's transmission rates in which case they would have showed revenues and these revenues would have to be credited against cost of service (affiliate revenues would have been netted out).[65]

177. The record in this case reflects that during the test period AEP companies paid each other RTOR. Mr. Bethel testified that when an affiliate sale occurs, the portion of the sale relating to transmission service is booked in a transmission revenue account. Tr. at 1304:1-4. Therefore, elimination of the RTORs has saved one AEP company the same amount of revenue lost by the other company. Mr. Norton explained that there is no real difference between these scenarios. Ex. AMP-1 at 30. For example, if pre-December 1, 2004, the generating entity paid the transmitting entity $1,000, the transaction showed up as an expense to the former and revenue to the latter, with a net of zero to the combined utility. After December 1, the generator saved $1,000, matched by the transmitter's "loss" of the same amount, with the same zero impact. If the utility in this situation is permitted to recover $1,000 in lost revenues from outside sources (like AMP-Ohio), the

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[65] AEP notes that Staff's assertion of an exclusion for a bundled price contract between Cinergy and BPRA which resulted in double recovery is not correct because Cinergy has not asked for a SECA for the contract from April 2005 through March 2006 and thus the only potential issue dealing with this contract is for four months (December 2004 through March 2005). AEP/Exelon admit that the issue could have been raised by BPRA as a shift-to-shipper claim had such a claim been brought. Based on the findings above the issue is a moot point.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

combined utility will not be "revenue neutral" but will be ahead by $1,000, on the backs of LSEs. This testimony is given substantial weight. Therefore, it is found that it is necessary to reduce the claimed lost revenues by eliminating from the claimed total any and all RTOR charges paid by an affiliate.

178. The expressed intent of the Commission in imposing a SECA is to provide for reimbursement of lost revenues to an entity; there should be no inclusion of payments that the entity made to itself in the quantification of lost revenues. In other words, no SECA should be collected for, and turned over to, an entity that formerly paid itself a RTOR that has now been eliminated. Most parties agree with Staff's assertion that merchant affiliate transactions should be excluded if their inclusion would lead to additional revenue recovery for the TOs and its affiliates from elimination of the RTORs.[66]

179. The TOs have the burden of proving both their lost revenues and lost revenue calculations were just and reasonable. As a matter of fact, the Commission directed the RTOs and TOs to "provide supporting documents containing calculations and data," including OATi tag data used, and "detailed narrative descriptions of all adjustments to data and calculations performed. . . ." June 16 Order, 111 FERC ¶ 61,409 at P 37 n.12.[67] There is no evidence demonstrating that affiliate transactions are properly recoverable as lost revenues for purposes of the SECA charges.

180. The inclusion of AEP intra-corporate RTOR payments in the lost revenues being submitted by AEP is substantial. The removal of the revenues associated with AEP-affiliate RTOR payments would reduce AEP's lost revenues by approximately $88 million. In other words, according to BGE, AEP will be picking up that amount of new net earnings never before realized at the expense of non-native load customer rate zones, and indeed in part from the stockholders of competitor TO companies, some of whom have no recourse under state settlements to pass on the payments in retail rates. BGE IB at 27-30.

181. Quest/ ESI provided an explanation of why inclusion of merchant function

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[66] As stated by BGE, this is strictly a factual matter that there are no lost revenues to a corporation when intra-company transfers are ceased; it is a non-economic event to the corporate shareholders. BGE RB at 20 n.20.

[67] Filing of Changes in Rate Schedules, 18 C.F.R. § 35.13(e)(3)(2005) (utility that files rate increase has burden of proof); *accord Am. Elec. Power Serv. Corp.*, 113 FERC ¶ 61,050 at P 22 (2005) (a company filing under §206 of the FPA bears the burden of proof); *see also Keyspan-Ravenswood, Inc. v. New York Independent System Operator, Inc.*, 101 FERC ¶ 61230 at P 28-30 (2002) (accepted Commission ordered compliance filing as reasonable).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

revenues in lost revenues creates a windfall for TOs: by including as lost revenues transactions from its merchant organization, the TO collects additional money coming in from outside of the utility in the form of the SECA from LSEs while its merchant organization merely no longer incurs an internal cross charge for transmission costs for RTOR service. Money formerly transferred from the left pocket to the right pocket within the utility is replaced by an equal amount of money coming into the utility from the outside – thus the "double recovery" for the TO and its affiliates. Quest IB at 22-34.

182. The record reflects that nearly fifty percent of AEP's transmission system is used by its generation/merchant function. These transactions were included in AEP's lost revenues. Tr. at 1315:22. Quest/ESI and Strategic imported power supplied from AEP generation and their SECA obligations to AEP are $15.5 million and $8.7 million, respectively. If AEP's generation/merchant function-related revenues are removed from AEP's lost revenues, each of Quest/ESI and Strategic's obligations to AEP will be cut approximately in half. Quest IB at 22-34.

183. As described by Quest/ESI, traditional utilities like AEP, which have not spun off their generation functions into a separate company, have transmission and generation components under the same corporate umbrella. AEP's generation/merchant function makes transmission reservations on the OASIS of AEP's transmission function. Rather than making a payment to its transmission function, AEP as a utility makes intra-company transfers for accounting purposes to reflect both the cost and the expense to the utility. Ex. QST-1 at 22:7-18; Ex. QST-1 at 22:1-27:11. On a total utility basis, AEP is therefore revenue neutral upon the elimination of the RTOR – the TO no longer collects a transmission revenue and the generation/merchant function no longer incurs a transmission expense. The revenue requirement of the TO is not affected. Quest IB at 22-34.

184. Mr. Zakem's testimony details how this "inter-departmental sale" of transmission works. Ex. QST-15 at 5:18-7:23. In Mr. Zakem's example, the merchant function has $200 of transmission expenses, of which $100 is for local network service by the generation function, $75 is for T&O service by the generation function and $25 is for transmission service paid to non-affiliated TOs. Before and after the elimination of the RTOR, the TO revenue requirement would be determined as follows, and does not change:

Item	**With T&O Rates**	**T&O Rates Eliminated**
Merchant generation cost	$2000	$2000
Merchant cost of transmission service	200	125
Transmission cost	1000	1000

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Transmission interdepartmental sales	- 175	- 100
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Revenue requirement	$3,025	$3,025

185. According to Mr. Zakem, the revenue requirement of $3,025 is independent of the amount of internal cross-charges. Internal corporate cross-charges do not create external costs. The inter-departmental sales adjustment recognizes the fact that internal cross-charges do not affect total corporate costs and so are not part of the revenue requirement. This testimony is given significant weight.

186. Evidence in this record demonstrates that AEP admits that it utilizes interdepartmental adjustments to account for its affiliated transmission transactions. In a memo dated September 30, 1998, AEP illustrates how to treat transmission expenses of AEP Power Marketing on the corporate books. Ex. QST-17. Corporate earnings are not affected by the elimination of the RTOR, there is no change in total money earned by the corporation. AEP's September 30, 1998, memo acknowledges that there is no impact on earnings from offsetting internal charges and revenues. This lack of effect on earnings is further supported by statements of Susan Tomasky of AEP in oral testimony in Docket No. ER03-262-001, *et al.*, on September 29, 2003, at Tr. at 55, where witness Tomasky states:

> **Q.** Then for the part that is transmission service, can you tell me the annual revenue from that?
>
> **A.** Last year, it was around $300 million. That was the discussion I gave you earlier, which was split between that which was paid internally and, therefore, does not produce net earnings, so from amounts that are paid under the FERC tariff by our generation to transmission and roughly the other half comes from third parties.

187. Consequently, it is found that affiliate transactions which are inter-departmental adjustments do not result in net earnings. The elimination of T&O rates does not affect a utility's costs attributable to internal charges by one affiliate to another. Therefore, inter-affiliate transactions should not be included in the lost revenues for the imposition of SECA obligations.

188. The Commission in the past has also been concerned with affiliate issues which may influence the decisions companies make to join RTOs. To wit,

> [D]ecisions as to which RTO to join may be affected by inter-RTO rate pancaking. That is, transmission owners may be driven by the interests of their merchant function, rather than motivated by a desire to achieve the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

> most rational and efficient RTO configuration, resulting in inappropriate RTO configuration that places the transmission owner's merchant function at a competitive advantage relative to other similarly situated market participants. Indeed, in this proceeding, one transmission owner stated that Midwest ISO's through and out rate was a factor in its decision to join PJM, and both Midwest ISO and PJM agreed that this is an issue.

July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at 34 (footnotes omitted).

However, this is not the matter at issue here since the TOs have already made their decisions as to RTO participation and the issue in this case is which are the lost revenues that should be used to determine the SECA to be imposed as a transitional rate for the elimination of rate pancaking across the two RTOs.

189. Therefore, it is concluded that inclusion of merchant affiliate transactions is unjust and unreasonable since it creates a financial windfall for the utility, contrary to the Commission order that "[t]he SECAs were not intended to provide greater revenues" for the utility. Order on Going Forward Principles, 106 FERC ¶ 61,262 at P 20. The SECA is not intended to supplement profits of a merchant affiliate. Therefore, affiliate transactions must be excluded from the lost revenues upon which the SECA is calculated.[68] It is concluded that the lost revenues in the compliance filings must be recalculated in accordance with this conclusion.

Issue 2. B. Should test period lost revenues include revenues for non-firm transmission service that are distributed by PJM under Section 27A of the PJM open-access tariff to firm transmission customers?

Parties' Contentions

190. Under Section 27A of the PJM open-access tariff, transmission revenues from non-firm point-to-point transmission service are credited by PJM to transmission customers. All parties to the proceeding agree that lost revenues for non-firm transmission service should be included as lost revenues and should continue to be credited to transmission customers. Staff IB at 6-8; Certain Classic PJM TOs IB at 6-7.

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[68] Ormet argues that if affiliate transactions are excluded, it should not be liable for any SECA charges for any transmission service related to the Exelon and PECO supply contracts since Exelon and PECO secured transmission service from their affiliate, ComEd. The findings and conclusions above are limited to the issue of affiliate transaction revenues as a component of lost revenues in the compliance filing. SECA obligations of particular entities will have to be recalculated based on the findings and conclusions finally ordered by the Commission on exceptions from this Initial Decision.

Discussion/Findings/Conclusions

191. As stated above the parties agree on this issue. Ex. Nos. CTO-6 at 5; S-1 at 12: 8-11; Tr. at 780:18-81:11. Given this agreement and in light of the fact that continuing revenue crediting will benefit customers, it is found that test period lost revenues shall include revenues for non-firm transmission service (distributed by PJM under Section 27A of the PJM open-access tariff to firm transmission customers).

Issue 3: Rate Design

A. Basic Structure – Allocation and Rate Design:

1. Do the proposed SECA rate designs comply with the Commission's orders and are the resulting lost revenue allocations just and reasonable?

2. Are there known and measurable changes that should be reflected in developing SECA charges?

3. Are the proposed revision to each RTO's tariff just and reasonable?

Midwest ISO TOs' Compliance Filing

192. As noted earlier, in the Midwest ISO TOs' compliance filings, Mr. Heintz, used a six-step process to analyze the OATi tag data, develop an average rate, and calculate the SECAs. Steps four and five deal with allocation and rate design issues involved in developing his proposed SECA.

193. In Step 4, Mr. Heintz calculated an average rate for T&O transactions for each transmission provider in the Midwest for each of the four time periods. The methodology Mr. Heintz used is referred to as the "total method." There are three calculations involved in Mr. Heintz' development of an average rate using the total method. Midwest ISO TO IB at 25-30.

194. First, Mr. Heintz calculated the average rate for each of the Midwest ISO TOs for that portion of 2002 and 2003 that the TO was not in the Midwest ISO. Mr. Heintz divided his T&O revenues from Step 1 by the non-grandfathered T&O MWhs calculated in Step 3. Rather than calculate an average rate for Northern States Power, Mr. Heintz used its hourly open-access transmission rate as a proxy for January 2002. *Id.* At 25-26

195. Second, Mr. Heintz calculated an average rate for MAPP. Because all MAPP members are not Midwest ISO TOs, only the MAPP out and through revenues associated with the Midwest ISO TOs were used. *Id.* At 26.

196. Third, Mr. Heintz calculated an average rate for the Midwest ISO. Mr. Heintz

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

made two adjustments related to this calculation. He removed both the revenues and MWhs associated with the transactions that left the Combined Region via the Midwest ISO point of delivery to Ontario Hydro and did not come back into the Combined Region. In addition, Mr. Heintz reduced the Midwest ISO TOs' revenues to reflect the Midwest ISO's refund report filed on November 14, 2005 to reduce the return on equity, as ordered by the Commission. *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,355 (2005). Then, Mr. Heintz calculated the average rate for the Midwest ISO for each rate period by dividing the adjusted lost revenues by the total out and through MWhs. Midwest ISO TO IB at 27-29.

197. In Step 5 of the six-step procedure, Mr. Heintz allocated to PJM entities the lost revenues of the Midwest ISO TOs. To calculate the allocated amounts, Mr. Heintz multiplied the average rates determined in Step 4 by the non-grandfathered out and through MWhs calculated in Step 3. The resulting monthly amounts are the SECAs, which are reflected on Schedule 21 of the Midwest ISO Tariff, included in *pro forma* format in Exhibit No. 148. *Id.* at 29-30.

AEP/Exelon Compliance Filings

198. Dr. Henderson, testifying on behalf of the New PJM Companies and Exelon, also proposed that an average rate methodology be used for designing the SECA charges. Dr. Henderson used the "footprint method" to allocate lost revenues on behalf of AEP, ComEd, Dayton and Dominion; he used a "modified total method" on behalf of PJM. Exhibit Nos. PTO-1 at 20-25; AEP/Exelon IB at 25-26.

199. According to Dr. Henderson, the footprint method is used because it is possible that reservations with PODs inside the PJM-MISO Combined Region were used to deliver power to sinks outside the Combined Region, and conversely, that PODs outside the Combined Region could have been used to deliver power to sinks inside the Combined Region. He therefore testified that it is important in developing SECA obligations (1) to account for deliveries outside of the Combined Region, and (2) to recognize that only load located inside the Combined Region is required to bear any responsibility for recovery of lost revenues. According to AEP/Exelon, the footprint method used by Dr. Henderson for AEP, ComEd, Dayton and Dominion includes only those revenues that are lost due to the elimination of T&O rates, and allocates those lost revenues to load within the Combined Region. *Id.* at 25.

200. Dr. Henderson used a modified total method on behalf of PJM. Using information provided by Messrs. Dessender and Bustard, Dr. Henderson calculated the PJM average rate by including all revenues and MWh for *firm* T&O transmission service provided by PJM, except those with a POD of the NYISO. For calculating non-firm revenues, he made two adjustments. First, he excluded all *non-firm* revenue and MWh with a POD of the NYISO. Second, he excluded the congestion component of the non-firm revenues

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

quantified by Witness Dessender. *Id.* At 26; Ex. PTO-1 at 23-25. Next, Dr. Henderson developed the amount of energy delivered over the non-NYISO PODs. Finally, he divided the revenue figure by the total amount of energy delivered over non-NYISO PODs. Ex. PTO-1 at 25:11-16. The average rate developed for PJM would apply to all Classic PJM members, including PECO. PTO-1 at 23:14-25:16.

201. The SECA rates for the FirstEnergy zones in PJM were calculated for December 1, 2004 by dividing the Midwest ISO SECA obligation allocated to the FirstEnergy zone by the 2003 zonal peak load for the FirstEnergy zone. Ex. FE-1 at 8:20-22. The FirstEnergy SECA obligation for 2003 and 2004 was determined on the basis of the ratio of FirstEnergy's zonal peak load to the sum of the zonal peak loads for all of the TOs. *Id.* at 8:1-8.

202. Dr. Henderson determined the average effective transmission rate for T&O transactions from the Duquesne zone by dividing the lost revenues by the eligible MWh of transmission service. Ex. DLC-1. SECAs owed to Duquesne were then calculated by applying the average rate to the applicable scheduled transmission service sinking in the Combined Region, as determined through the OATi tag data consistent with Commission orders. Duquesne IB at 5-6.

203. To develop the proposed SECA for AEP, ComEd, Dayton and Dominion, prior to each company's integration into PJM, Dr. Henderson divided each company's lost revenues by the amount of energy (in MWh) sinking in the Combined Region. Ex. PTO-1 at 23. To develop the average SECA rate for T&O transmission service provided by the pre-expansion PJM TOs under the PJM open-access tariff, Dr. Henderson divided lost revenues by the total amount of energy (in MWh) delivered over the non-NYISO PODs. Ex. PTO-1 at 24-25. The proposed SECAs for each PJM TO are set forth in Attachment X to the PJM open-access tariff. In his Supplemental Direct Testimony, Dr. Henderson corrected the 2003 PJM average rate based on information received during discovery concerning a reservation to a Dominion POD where 97.98 percent of the energy was redirected to the NYISO. AEP/Exelon IB at 26. Dr. Henderson testified that in a future compliance filing, the 2003 average rates will have to be reduced to correct that error.

Parties' Contentions

204. Both the Midwest ISO TOs and the PJM TOs contend that calculating an average rate as one of the steps in designing the SECA comports with the Commission's November 17 and 18 Orders. They further contend that an average rate is consistent with the methodology used in the earlier proceedings in these dockets to which the Commission pointed as guidance for the development of the SECA mechanism. Finally, as a practical matter, they contend that an average rate is the only way to calculate SECAs using the OATi tag data. For example, Mr. Heintz explained that with the advent of power marketers, it is almost is impossible to calculate directly the transmission

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

charges paid to transmission owners because of the increased number of transactions involving power marketers who do not have detailed bills showing the amount of transmission charges paid by the power marketers, nor do the bills show to whom the marketers paid those transmission charges. Ex. MTO-1 at 23:21-24:3 and 25:1-2. Further, AEP/Exelon argue that the application of an average rate is the only practical method to implement this energy-based allocator for recovering transmission revenues that, during the test periods, were derived from a capacity-based reservation system. AEP/Exelon IB at 24.

205. Although the Midwest ISO TOs and the PJM TOs agree on the use of an average rate, they do not agree on how an average rate should be calculated. AEP/Exelon argue that the Midwest ISO TOs' total method for developing an average rate method does not rely upon an independent calculation of lost revenues, but rather estimates such revenues by taking a transmission provider's total amount of T&O revenues in the test period (without regard to whether such revenues were for transactions to sinks in the Combined Region), and divides this amount by the total amount of energy delivered (without regard to whether the sink was inside or outside of the Combined Region). Thus, the total method estimates lost revenues through an indirect allocation measure. AEP/Exelon contend that the footprint method is a more accurate measure of revenues lost due to the elimination of rate pancaking within the Combined Region. *Id.* at 25.

206. On the other hand, Four TDUs, the Midwest ISO TOs, Ormet and Quest oppose the footprint method.[69] Ormet and Quest note that the footprint method for developing an average rate creates an asymmetry which inflates the SECA for load in the Midwest ISO and in the Classic Area of PJM. Ormet IB at 36; Quest IB at 34-43. Further, the Midwest ISO TOs, Ormet and Quest note that the footprint method is inconsistent with cost causation principles, because it creates situations in which parties may be responsible for costs which they could not have caused. Four TDUs RB at 15-20; Quest IB at 34-43; Ormet IB at 37; Midwest ISO TOs IB at 38-41.

207. Quest uses as an example a transaction with energy sourcing in the AEP control area, exiting AEP at a PJM POD, and subsequently exiting PJM and sinking in the Carolina Power & Light control area. The cost of transmission associated with this transaction, and other transactions similar to it, resides with the entity outside the Combined Region where the energy was ultimately delivered. Ex. SE-1 at 12:11-17. The opponents of the footprint method argue that cost responsibility is shifted to entities inside the Combined Region from those entities outside the region which receive the benefit from the elimination of RTORs for transactions that either cross the MISO-PJM

[69] Quest supports the Midwest ISO TOs' total method for developing an average rate. Quest IB at 34-43.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

border or exit the New PJM companies and pass through PJM prior to sinking outside the Combined Region. Quest IB at 34-43.

208. Further, AMP-Ohio contends that the use of an average rate in both the Midwest ISO TOs' proposal and the PJM TOs' proposal does not produce just and reasonable allocations of the SECA responsibility. AMP-Ohio IB at 33. AMP-Ohio's witness, Mr. Norton, explains that the average rates proposed in this proceeding assume that all entities scheduled load at similar load factors, a fact which is clearly not true. Ex. AMP-1 at 16. As Dr. Henderson notes, the average rate approach shifts cost responsibility from low- to high-load factor transmission users. Ex. PTO-1 at 16 (corrected) MISO TO witness Heintz agreed that, under the average rate approach, an LSE that reserved 100 MW of cross-border transmission in the historical period, but scheduled nothing over that path would be responsible for lost RTOR revenues; but would pay no SECA, because the lost revenues would be charged to others. Tr. At 915-10-17:18. AMP-Ohio argues high-load factor customers are penalized for using the transmission systems efficiently. AMP-Ohio contends that this result is unjust, unreasonable and unduly discriminatory. AMP-Ohio IB at 33-34.

209. As a hypothetical example, Mr. Norton explained that if each of two LSEs had reserved one MW of transmission that crossed the PJM/MISO border for one year, and if the RTOR was $1,000 per MW month, there would be total lost revenues of $24,000 ($1,000 per month for twelve months for each of the LSEs). The next assumption is that one LSE used its reservation for 1,000 hours during the year, while the other used it for 7,000 hours. Under the average rate method used by the TOs, the average rate would be calculated by dividing the $24,000 of lost revenues by the 8,000 MWh of schedules, producing a rate of $3 per MWh. Application of that rate to the schedules of each LSE produces an annual SECA charge to the low-scheduling LSE of $3,000 and an annual SECA charge to the high-scheduling LSE of $21,000, even though each had paid $12,000 in RTORs. Ex. AMP-1 (corrected) at 17-18.

210. Mr. Norton explained that this type of disparity in scheduling is, unfortunately, all too real, as are the unduly discriminatory impacts. He describes the impact on AMP-Ohio member Cleveland Public Power (CPP) which schedules 10 MW, around the clock, from an AMP-Ohio power plant located in PJM. In 2002, CPP scheduled 87,600 MWh from the plant, creating an annual SECA obligation of $890,900.76. The PJM RTOR in effect as of April 1, 2002, was $21,363 per MW/year, which multiplied by the 10 MW transmission demand resulted in an "out" transmission charge for CPP of $213,600 for one year of service. Under the proposed average rate methodology, CPP was assessed a SECA of nearly $900,000 on an annualized basis to replace "lost" RTOR revenues of a little more than $200,000. *Id.* at 18-19.

211. Mr. Norton presented another real-life example: the City of Painesville, Ohio, which has a 2 MW transmission reservation that is near a one hundred percent load factor

usage. As a result of the proposed average rate methodology, Painesville has been assessed a monthly SECA of approximately $7,440, which is equivalent to a $10 per MWh transmission adder. *Id.* at 20.

212. AMP-Ohio further contends that the Midwest ISO TOs and AEP/Exelon do not even attempt to defend that the rates are just and reasonable in the face of contentions by AMP-Ohio and others that the average rate method produces unjust and unreasonable results. AMP-Ohio RB at 29-30. AMP-Ohio further contends that it is not appropriate for the TOs to assert that they relied on prior Commission orders and practicalities to justify an unreasonable end result. Here, it is especially inappropriate to rely so heavily, if at all, upon what can best be described as the Commission's understanding that a "load" and OATi tag-based charge would be in the form of an energy charge. According to AMP-Ohio, the Commission's orders were issued in a vacuum and written on a previously pristine slate. There had never before been SECA charges of the type imposed here, where prior usage of capacity-based transmission was to be translated on a dollar-for-dollar basis into future energy-based charges. At the time of the Commission's orders setting the SECA in motion and this case for hearing, there was no basis on which the Commission could have known what level of SECA charges would result, and how those charges would compare with the eliminated RTOR revenues on anything other than a total system basis. *Id.* at 30-31.

213. AMP-Ohio proposes a creative approach, to the extent SECA charges exceed the level of past RTORs, or, alternatively, exceed the amount that would have been received under the highest applicable filed RTOR. Under this approach, the SECA is reduced and any unpaid amounts get "socialized" to all load in the region, on the theory that all load benefits from the elimination of RTORs. AMP-Ohio IB at 36-37.

214. Ormet objects to the rate design proposals set forth by the Midwest ISO TOs and the PJM TOs because the methodology differs in two significant ways from that presented by Mr. Heintz in his November 14, 2002 testimony. The 2002 testimony set forth a SECA methodology upon which the Commission provided guidance for this proceeding. Ex. ORM-4. First, Ormet notes that in his 2002 testimony, Mr. Heintz proposed a more traditional rate design methodology, in which rates are designed to recover test period revenues by transition period billing determinants. Ormet IB at 17, 31- 41.

215. Ormet opposes this change from a usage charge to a stated rate based on the wishes of unidentified parties. Ormet IB at 13-16. Secondly, Ormet objects to the fact that the stated rate is specifically designed to recover the amount of revenue for T&O transmission service received during the historical period. Tr. at 1154:1-13, 1155:2-9, 2180:20-24. Ormet notes that Dr. Henderson testified that the amount collected under the New PJM Companies' proposal would not be the same as the amount of revenue which would have been collected by charging the RTOR during the transition period. Ex.

ORM-2 @ 19; Tr. at 2178-80:13-25. Thus, Ormet contends that under the compliance filings, the TOs will collect from LSEs during the transition period the same amount of revenues attributed to LSEs during the test periods. Ormet IB at 30-65.

216. BGE also argues that LSEs may be paying double charges because historical data causes billings to go to the same load, even though a different LSE may be serving that load under a new contract, that LSE would pay a SECA to replicate payments made by its predecessor under an expired contract as well as payments to currently serve the load under a different contract with another supplier. BGE IB at 23.

217. Mr. Heintz proposed that the PJM open-access tariff include a collection mechanism that provides a means to avoid shortfalls in collection of lost revenues. Ex. MTO-4. AEP/Exelon state that Mr. Heintz' proposal should be rejected because the SECA rates filed by the New PJM Companies will recover all of MISO TOs' lost revenues. AEP/Exelon further state that the compliance filing made by the MISO TOs fails to recover significant portions of the lost revenues allocated to the ATSI zone. Therefore, AEP/Exelon recommend that the Midwest ISO open-access tariff should be revised to comport with the PJM open-access tariff in a manner than ensures full collection of the PJM TOs' lost revenues. AEP/Exelon IB at 15-17.

218. AEC and SMECO argue that the SECAs are unjust and unreasonable because they are not limited to those importing utilities that actually benefited from the use of the exporting utility's facilities in the historical test period, nor do they allocate cost responsibility in proportion to such benefits. According to these companies, the proposed SECAs result in the improper imposition of charges on entities such as AEC and SMECO, for which there is no evidence to demonstrate that they used the TOs' transmission systems. AEC-SMECO IB at 14-15. Further, AEC and SMECO fault the compliance filings because they do not attempt to apply the new charges in the same proportion as entities' former payments of RTORs in the historical period. For example, within PJM, the filed SECAs are paid equally by all transmission users that serve load, regardless of their imports during the historical period. Moreover, in retail choice states in PJM, it is impossible to collect charges in 2005 on the entities that originally entered into transactions in 2002. This is so because entities are constantly entering and exiting the market. AEC and SMECO aver they did not pay RTORs and should not pay any SECAs since they did not use power that crossed the PJM/MISO border. *Id.* at 18.

219. Unlike the development of a transmission rate, Quest/ESI explain that the TOs have developed a transition charge based on "lost revenues" for a period that is only four months long and the TOs were already compensated for transmission revenues with the RTOR. They suggest that the factual circumstances are more akin to a utility changing its rate design, not just its rates.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Ormet's Proposal

220. Ormet proposes an alternative to the SECA developed in the compliance filings. In its proposal, which is sponsored by Mr. Russell, Ormet proposes that SECA rates be developed in the traditional manner – by dividing test year revenues by test year load (MWh). Ormet proposes that the resulting per unit MWh SECA rate be applied to actual monthly billing determinants for the transition period. Ormet's proposed SECA is a usage rate.[70]

221. The Midwest ISO TOs contend that under Ormet's proposal, most of the LSEs they serve will pay more in SECA revenues than they would pay under the Midwest ISO TOs' proposal. The Midwest ISO TOs also contend that since the Commission's general policy is to make rate design changes prospective and because the transition period has ended, any radical changes in rate design may result in the shift of millions of dollars of SECA costs.

222. At first, AEP/Exelon argue that such a proposal "would have been met with fervent opposition from the vast majority of stakeholders." In fact, Mr. Heintz stated that he "heeded the wishes of the majority of stockholders [*sic*]," who expressed a desire for a stated rate. AEP/Exelon IB at 35. However, in their reply brief, AEP/Exelon agree that rates could be designed using test period load and applying the rate to an LSE's load during the billing period. Within PJM, the commonly used measure of an LSE's load is the prior year's 1-CP, not actual load each billing month. See Section 34.1 of the PJM open-access tariff. AEP/Exelon contend that if the Presiding Judge determines that the proposed SECA, which is designed to recover test period lost revenues, regardless of increases or decreases in load, violates ratemaking principles, then the rate design should be revised for all non-settling parties, not just Ormet. Moreover, AEP/Exelon contend that the billing determinants for applying rates during the transition period should be consistent with those commonly used by PJM – the prior year's 1-CPs. During cross-examination, Mr. Whitfield agreed that use of the prior year's 1-CP as the billing determinant would result in an intra-PJM SECA obligation for Ormet of approximately $3.5 million. Tr. at 2230:23-2231:18; AEP/Exelon RB at 26-27.

Discussion/Findings/Conclusions

223. The allocation and rate design proposals for determining SECA responsibilities

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[70] Mr. Russell sets forth an alternative rate in which subzones are reflected. Exhibit No. ORM-2 at 43. He also recommends that if MWh rates are not adopted, that MW rates reflect monthly coincidental peaks (CP). *Id.* at 45.

proposed by the Midwest ISO TOs and the PJM TOs do not comply with the Commission's directives in these proceedings. First, both sets of compliance filings use an average method for allocating revenue responsibility among customers. While the average method can be a legitimate way to allocate revenue responsibility, as suggested in the July 23 Order on Initial Decision, in this proceeding the use of the average methodology produces absurd results. Second, both sets of filings deviate from the guidance provided by the Commission on how the SECA should be developed. Third, the allocation and rate design methodologies proposed by both the Midwest ISO TOs and the PJM TOs do not follow cost causation principles. Finally, the proposed allocation and rate design proposals do not balance the expressed Commission goals for developing a SECA mechanism. Therefore, the allocation and rate design methodologies do not result in a SECA mechanism which is just and reasonable and not unduly discriminatory.

224. Based on the testimony of Mr. Heintz on November 14, 2004, the Commission provided guidance on how the SECA mechanism should be developed. July 23 Order on ID 104 FERC ¶ 61,105 at P 54. Under Mr. Heintz' 2004 proposal, the SECA would be based on actual billing units, which is a type of usage charge. Ex. ORM-4 at 25-26 and 39. In the compliance filings, the Midwest ISO TOs and the PJM TOs changed the SECA mechanism from a usage charge to a fixed charge. Under a usage charge, the SECA would be assessed on actual monthly billing units. With the proposed fixed charges, the SECA is a fixed demand-type charge which is not based on current usage.

225. Both Mr. Heintz and Dr. Henderson tried to explain the rationale which led to the change from a usage charge to a stated rate. Mr. Heintz stated that the MISO stakeholders conducted a meeting at which participants determined they wanted a stated charge and so he had developed MISO's SECA charges as a stated monthly amount. Tr. at 861:4-12. Mr. Heintz further stated that as far as he knew, no PJM customers were at the stakeholder meeting, even if PJM TOs were in attendance. Tr. at 867:10-16. Dr. Henderson cited the same meeting as the reason behind the PJM TOs using a fixed dollar obligation, but stated that he had only heard about the stakeholder meeting from Mr. Heintz. Tr. at 2193:3-16.

226. The record does not support the proposition that the majority of stakeholders supported the change. Mr. Heintz' recollection of the meeting was poor. Tr. at 867:10-16. Dr. Henderson's knowledge of the meeting was hearsay. Further, there is a lack of evidence demonstrating that the issue was brought before the stakeholders, much less supported by the majority of them. Finally, neither Mr. Heintz nor Dr. Henderson provided reasonable explanations as to why a change from a usage charge to a stated rate is required.

227. The SECA proposals filed by the Midwest ISO TOs and the PJM TOs do not follow the principles of cost causation. Cost causation is one of the bedrocks of cost allocation and rate design principles. As far back as 1944, the Supreme Court approved

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the Commission's setting a gas pipeline rate utilizing "actual legitimate costs" to set a rate of return. In so doing the Supreme Court stated that the rate-making process to be followed by the Federal Power Commission under the Natural Gas Act (15 U.S.C. § 717 (2005)) should include consideration of the interests, not only of the consumers, but also of the investors, in order that returns on investments may be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. *See Fed. Power Comm. v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

228. In a more recent case, in which a utility was proposing a change in ratemaking to recognize the shift from the era of non-interconnected utility systems to an era of integrated, open-access electric industry, the Commission again addressed this bedrock issue when it stated, "[T]he fundamental theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred." *Northern States Power Co., 64 FERC* ¶ 61,324 at 63,379 (1993).

229. In addition, the Commission addressed the bedrock issue of cost causation in its orders in this proceeding. Specifically, the Commission stated:

> Consistent with the principle of cost causation, the load of an importing utility should pay a fair share of the costs of the exporting utility's transmission facilities for its use of those facilities. Historically, such payments were made via transactional-based charges which have been determined by the Commission to no longer be just and reasonable for the combined region. Therefore, the Commission is developing the transitional rate mechanisms to ensure that the parties continue to pay the costs of facilities that they use and from which they benefit. The lost revenue recovery mechanisms are calculated based on the revenue recovered through the just and reasonable rate charged in a historical period for through and out service and will approximate the exporting utility's cost of providing such service to the importing utility's load. The new transition rate mechanism would allocate such costs in proportion to the benefits received while holding transmission owners revenue neutral. The transitional rate mechanism is designed to approximate the expected use of the exporting utility's transmission system during the two year transition period. Therefore, these lost revenue recovery mechanisms are consistent with the principle of cost causation during the transition period.
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> November 17 Order, 105 FERC ¶61,212 at P 48 (*footnotes omitted*).

See also California Indep. Sys. Operator Corp., 113 FERC ¶ 63,017 at P 39 (2005); *Louisiana Pub. Serv. Comm. v. FERC,* 184 F.3d 892, 896 (D.C. Cir. 1999). Such rates

should "fairly track the costs for which [the customers] are responsible." *Pennsylvania Elec. Co. v. FERC*, 11 F.3d 207, 211 (D.C. Cir. 1993), *citing Town of Norwood v. FERC*, 962 F.2d 20, 25 (D.C. Cir. 1992); *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1198 (D.C. Cir. 1989).

230. The Commission clearly intended that the SECA mechanism allocate costs to load in proportion to the benefits they receive from the elimination of the RTOR. The compliance filings in this proceeding do not achieve this objective. For example, by using an average rate as one of the steps in designing the SECA, and by developing a fixed charge rather than a usage charge, the SECAs are designed to guarantee that SECA revenues during the transition period equal T&O revenues from the historical period. With all of the changes in the electric industry during the time of these proceedings, an assumption that load will remain constant is a faulty assumption. The only way to assure that costs associated with providing transmission service are equitably paid by those that receive the benefits of the elimination of the T&O rates is to adopt a non-by-passable usage charge. As shown by Ormet, assessing a demand-type SECA, which is based on historical data, inequitably assigns to Ormet costs for transmission services in the transition period for which it did not benefit. Ex. Nos. ORM-2 at 13 Table 1 and ORM-2 at 44, Table 2, Column G.

231. The footprint method for designing an average rate is an example of how the PJM TOs' compliance filing does not follow cost causation. The footprint method is especially egregious, as it assesses costs to parties who could not possibly be responsible for costs associated with the elimination of the T&O rates. As stated above, Quest cites an example of a transaction with energy sourcing in the AEP control area, exiting AEP at a PJM point of delivery and subsequently exiting PJM and sinking in the Carolina Power & Light control area. The cost of this is being shifted to the LSEs in the Combined Region when it is really the entities outside the Combined Region who benefit. Under the bedrock principle of cost causation, parties may not be responsible for costs for which they could not have caused. *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300-01 (D.C. Cir. 1992) ("[p]roperly designed rates should produce revenues from each class of customers *which match, as closely as practicable, the costs to serve each class or individual customer*" (citation omitted) (emphasis retained)). Moreover, the examples cited above by AMP-Ohio and AEC and SMECO demonstrate how the rate design in the compliance filing results in unjust and unreasonable rates.

232. Based on the above, the SECA proposals of the Midwest ISO TOs and PJM TOs clearly violate the Commission's long-standing principle of cost causation.

233. In the section of this Initial Decision on "Lost Revenues," the conflicting goals set forth by the Commission for developing a SECA mechanism were addressed. Several of those goals need to be re-visited for the analysis of the appropriate allocation and rate design for the SECA mechanism. One goal was to minimize cost shifting as a result of

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the elimination of RTORs. November 17 Order 105 FERC ¶ 61,212 at P 42. A second goal was to hold utilities revenue neutral. Order Establishing Going Forward Principles, 106 FERC ¶ 61,262 at P 20. A third goal was to recognize that with the elimination of RTORs, there could be load growth and increased revenues and costs associated with such load growth. November 17 Order 105 FERC ¶ 61,212 at P 50.

234. The avoidance of cost shifting was one of the primary reasons for requiring a SECA as part of the elimination of the RTOR. *Id.* at P 9 and 44; November 18 Order 109 FERC ¶ 61,168 at P 56. As discussed above, the SECAs proposed by the Midwest ISO TOs and the PJM TOs do not avoid cost shifting; rather, by use of the average rate in the development of the SECA and in the use of a demand-type rate rather than a usage charge, the SECA proposals aggravate cost shifting among TOs. PJM witness, Mr. Dessender, clearly explains the issue -- the proposed SECA rate designs and resulting lost revenue allocations require payment of SECA charges by entities that did not benefit from the elimination of RTORs:

> **Q.** During the SECA period from December '04 through March '06, load within PJM would pay the zonal network rate in the zone in which they're located; is that correct?
> **A.** That's correct.
> **Q.** And on top of that, there will be a SECA; correct?
> **A.** Correct.
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> * * *
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> **Q.** We're back in the beginning of the RTORs, but I wasn't importing from either MISO or any of the New PJM Companies. I'm load within PJM. What would I pay?
> **A.** The network service rate [….] In the zone in which you're serving load.
> **Q.** Now let's go forward into the SECA period.
> **A.** You're still not importing?
> **Q.** I'm still not importing. What would I pay?
> **A.** The network service rate for the zone in which you're serving load and the two-part SECA rate for the zone or subzone in which you're serving load.
> **Q.** And that's without regard to whether I was ever importing from any of the entities that are collecting the SECA?
> **A.** Correct.
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> Tr. at 809:19-25; 810:25-811:15.

235. As shown in this colloquy, Mr. Dessender testified that prior to the elimination of RTORs, an entity that neither imported from either the Midwest ISO, Midwest ISO TOs or New PJM Companies paid only a network service rate in the zone in which that party was serving load. However, since the elimination of the RTORs and imposition of SECA that same load that is within PJM, including AEC and SMECO, pays the network service

rate for the zone in which that entity was serving load and the two-part SECA rate (one part for MISO TOs and one part of the New PJM TOs) for the zone or subzone in which it is serving load, without regard to whether that entity was ever importing from any of the entities that are collecting the SECA. Tr. at 811:8-15. As testified to by Mr. Solomon, this is precisely the case for AEC and SMECO. Ex. Nos. AEC-1 at 4:10-8:11 and SMC-1 at 4:12-5:8. Thus, it is clear that the methodology does not lend itself to revenue neutrality, but a cost shift imposed on entities such as AEC and SMECO.

236. In addition, Mr. Heintz, testified that "I did" impose a SECA on customers that would pay "zero" RTORs on current transactions if the RTOR were still in effect. Tr. at 903:19-904:16. Nevertheless, even AEP/Exelon agrees that the rate could have been designed differently. AEP/Exelon RB at 26-27.

237. Some parties argue that revenue neutrality means that the TOs are guaranteed recovery of 100 percent of their T&O revenues. This is not the case. Since cost-based SECAs are replacing cost-based T&O rates, revenue neutrality can only mean that TOs are provided a "reasonable opportunity" to recover their lost revenues through the SECA mechanism. In this proceeding the Commission concluded that it did not need updated cost studies for reviewing the companies' revenue requirement. *See* November 17 Order, 105 FERC ¶ 61,212 at P 49. Stated in a different way, the SECAs were devised to give the TO's a reasonable opportunity to recover what they would have recovered had the T&O rates not been eliminated. This is consistent with the Supreme Court's finding:

> [R]egulation does not insure that the business shall produce net revenues, nor does the Constitution require that the losses of the business in one year shall be restored from future earnings by the device of capitalizing the losses and adding them to the rate base on which a fair return and depreciation allowance is to be earned.

*Fed. Power Comm. v. Natural Gas Pipeline Co.***,** 315 U.S. 575, 590 (1942). (*question on other grounds by In Re Valuation Proceedings under Sections 303 cc)and 306 etc.,* 445 F. Supp. 994 (Regional Rail Reorg. Ct. 1977) (citations omitted).

238. Thus, the SECA mechanism should not provide a greater opportunity for TOs to recover their transmission revenues than they had with their now unjust and unreasonable T&O rates. Although the Commission's intent was for the SECA revenues to approximate the level of lost revenues, it would be merely coincidental if they were identical.

239. The Midwest ISO TOs contend that a shift from a stated rate to a usage charge will result in most of the LSEs they serve paying more in SECA revenues than they would pay under the Midwest ISO TOs' proposal. To the extent that a LSE transmitted more

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

energy over the Midwest ISO/PJM seam during the transition period than during the test period, that LSE should be responsible for increased transmission charges; conversely, to the extent that an LSE's cross-seam usage decreased, its transmission costs should also decrease. This is consistent with the Commission's goal that increased growth in transmission as a result of the elimination of T&Os may result in increased costs. A properly designed SECA will provide the opportunity for TOs to recover such costs. *See Fed. Power*, 315 U.S. 575.

240. Based on the above, it is found that the SECA mechanisms proposed by the Midwest ISO TOs and the PJM TOs do not comply with the Commission's directives in this proceeding and must be rejected. On the other hand, Ormet's SECA proposal satisfies the Commission's goals for developing a transitional mechanism. Consistent with the Commission's directive, the Ormet proposal uses OATi tag data and develops lost T&O revenues using 2003 data, the data for the most recent twelve months at the time of the first compliance filing, with adjustments for known and measurable differences, to most closely reflect future trading patterns. In addition, the Ormet proposal will recover revenues from customers, in proportion to the benefits that such customers receive from the elimination of T&O rates through a non-bypassable usage charge on load. Ex. ORM-2 at 45.

241. The Midwest ISO TOs note that the Commission usually makes changes in rate design on a prospective basis. Had the Midwest ISO TOs' November 2004 filing comported with the Commission's July 23 Order on Initial Decision and November 17 Order, the rates which took effect on December 1, 2004, subject to refund, would have been prospective. Any suggestion that this Initial Decision is recommending a radical change in rate design is misplaced; the Midwest ISO TOs purposefully changed the rate design method from a usage charge to a stated rate. The "blame" for any shift in dollars as a result of the lack of compliance rests solely on the TOs.

242. AEC's and SMECO's arguments will be resolved by the allocation and rate design methodology adopted in this Initial Decision. If it is correct that their supplies were largely met through their own generation or from contracts that did not require the payment of an RTOR during 2002-2003 then the new methodology should not reflect charges for them.

243. AMP-Ohio's creative approach is rejected since its socialization method would have the same cost causation flaws which have been found unjust and unreasonable. Ormet's alternative rate proposal is rejected as moot. Finally, based on the findings above, yet another set of compliance filings will need to be submitted to the Commission.

Issue 3. B: Existing Transactions & Relationship to the SECA Charges:

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

1. Should a customer's SECA obligation serve as a cap upon the total amount of revenues that can be collected from the customer under the combination of SECA charges and Existing Transactions?

2. Is the proposed process for crediting revenues from Existing Transactions reasonable?

Parties' Contentions

244. FirstEnergy argues that a customer's SECA obligation should serve as a cap on the total amount of revenues that can be collected for both SECA charges and Existing Transactions (ETs). FirstEnergy IB at 17. Under the transitional lost revenue recovery mechanism, transmission customers and LSEs are only obligated to pay the amount equal to its SECA obligation. *Id.* FirstEnergy claims that to ensure that this occurs, the Commission required the Midwest ISO and PJM to credit a customer's ETs RTOR charges against its SECA obligation. *Id.* It contends that, if a customer's ETs RTORs were less than its SECA obligation the customer paid the difference and if the ETs RTORs were more than the SECA charge the customer is entitled to a credit. *Id.* at 18.

245. FirstEnergy avers that the ET RTOs were intended to reduce the SECA obligations of LSEs.[71] In addition, FirstEnergy claims that the Commission required the unused credit for ETs RTOR payments to be rolled over and applied to the next month's SECA obligation. *Id.* at 22-23. FirstEnergy argues that any ETs RTOR credits unused at the end of the transition period should be refunded to the appropriate transmission customer. *Id.* at 23.

246. According to FirstEnergy, if a customer's SECA obligation does not serve as such a cap, the Midwest ISO TOs will realize a windfall. *Id.* FirstEnergy claims that it was assessed $6 million in SECA obligations for load served in PJM and paid $26 million in ETs RTOR charges to the Midwest ISO. *Id.* at 25 (citing Ex. FE-5). According to FirstEnergy, $6 million of the $26 million it paid in ETs RTORs was credited toward its assessed SECA charges satisfying its obligation to pay the Midwest ISOs their lost revenues. *Id.* However, FirstEnergy argues, the Midwest ISO TOs were not kept revenue neutral because it paid $20 million more than its fair share of the Midwest ISO TOs lost revenues. *Id.* This result, FirstEnergy contends, is unjust, unreasonable and unduly discriminatory. *Id.* at 27. FirstEnergy states that to remedy this, the Commission must require the Midwest ISO to refund FirstEnergy its $20 million in excess ETs RTOR credits. *Id.* at 26.

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[71] FirstEnergy IB at 22 (quoting November 17 Order at P 14, 45, November 18 Order at n.41, June 16 Order at P 32).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

247. FirstEnergy claims that it was assessed $26 million in ETs RTORs because FirstEnergy Solutions rolled over transmission transactions one business day before the Commission issued the November 17 Order eliminating RTORs. FirstEnergy. *Id.* at 27 (citing Ex. FE-2 at 11:19-24). The Midwest ISO deemed the rollovers ETs and billed FirstEnergy $26 million over the transition period. *Id.* (citing Ex. RTO-2; Ex. FE-5). FirstEnergy asserts that if the rollovers would have occurred one day later, on November 17, 2003, it would not have been subjected to any RTOR charges for ETs or otherwise. *Id.* FirstEnergy claims that this is *prima facie* evidence of undue discrimination since it is being assessed four times the amount of its assigned SECA than a similarly situated customer would have been assessed. *Id.* at 27-28.

248. FirstEnergy also argues that the proposed process for crediting Revenues from ETs is not reasonable. *Id.* at 29. Allowing the LSEs unused ETs RTOR credits to expire contravenes Commission orders and would be unjust, unreasonable, and unduly discriminatory, FirstEnergy argues. *Id.* at 30, 32. The unused credits will expire at the end of the transition period although the Commission directed the Midwest ISO and PJM to continue to apply the ETs RTOR credits against SECA charges each month. *Id.* at 30. The Commission viewed the credit as belonging to the individual transmission customer, FirstEnergy contends. *Id.* at 30-31 (citing Tr. at 1064:21-1066:9). Thus, FirstEnergy states, nothing in the Commission's orders allows the Midwest ISO to retain the credits (by allowing them to expire) and then distribute these amounts to the Midwest ISO TOs. *Id.* at 31-32.

249. FirstEnergy also contends that permitting the unused ETs RTORs to expire also violates the Federal Power Act because it would allow the Midwest ISO TOs to collect more than the lawful amount filed under the Midwest ISO open-access tariff in violation of the filed rate doctrine. *Id.* at 33-34. FirstEnergy asserts that the Commission should require the Midwest ISO to refund the amount of unused ETs RTOR credits with interest in accordance with 18 C.F.R. § 35.09a (2006). *Id.* at 35. FirstEnergy claims that since the methodologies used to implement the SECAs differ, the only crediting approach that can be applied generally is to cap ETs at the transmission customer's SECA obligations. *Id.*

250. Dayton claims that the TOs are not likely to recover their full amount of lost revenues as a result of any ruling that eliminates a LSE's SECA responsibility for charges assessed during periods when no service was provided. Dayton IB at 27. In addition, Dayton argues that since the Commission has ruled that TOs are entitled to recover all of their lost revenues, any elimination of SECA responsibility must be replaced by another source of funding. *Id.* at 27. Dayton also contends that the over-payments the Midwest ISO has collected for ETs should be used to fund any SECA revenue shortfall caused by the Midwest ISO's failure to fully recover the PJM TOs lost revenues. *Id.* at 28.

251. The Midwest ISO TO's argue that a customer's SECA obligation should not serve

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

as a cap on the total amount of revenues that can be collected under the combination of SECA charges and ETs RTORs. Midwest ISO IB at 50. According to the Midwest ISO TOs, the Commission's orders provided that RTORs for existing transactions were to continue to be assessed and remain the responsibility of the shipper and only be adjusted to provide a credit to the SECA obligation in the amount of the ETs RTORs they continue to pay.[72] In addition, they argue that the Commission did not direct that a customer's total obligation be capped at an amount equal to the SECA obligations.[73] They also contend that the Commission's language in the November 17 Order intended that the adjustments only mitigate the SECA obligations and not cap ETs RTOR obligations.[74] The Midwest ISO TOs state that it and the Midwest ISO revised the appropriate schedules of its open-access tariff so that under the revised open-access tariff customers under ETs continue to pay RTORs during the transition period. *Id.* at 52. The Midwest ISO TOs also contend that the Midwest ISO and PJM jointly submitted a filing on April 25, 2005 stating that they are coordinating to ensure customers receive a credit for the ETs RTORs they have paid. *Id.* at 53. Thus, the Midwest ISO TOs conclude the proposed revisions to the Midwest ISO open-access tariff and methodology for the treatment of ETs conform with the Commission's orders in this proceeding and should be accepted. *Id.*

252. Imposing a cap, would terminate payments under the ETs contracts once the SECA obligation is reached. *Id.* The Midwest ISO TOs claim that imposing a cap is inconsistent with the Commission's orders which directed that RTORs for ETs continue and is therefore a collateral attack on such orders and should be rejected. *Id.* In addition, the Midwest ISO TOs state that the Commission recognized that eliminating RTORs for ETs would not produce efficiencies because the customers had already contracted for service and therefore could not change their behavior. *Id.* at 55. The crediting mechanism proposed by the Midwest ISO and PJM is reasonable and consistent with the Commission's orders because it insures that ETs are not billed for both SECA and ETs RTORs. *Id.* at 57. The Midwest ISO TOs also state that, to the extent that ETs charges were greater than SECA obligations in a given month, both the Midwest ISO and PJM used the excess ETs charges to credit SECA obligations in future months.[75] In addition, the Midwest ISO TOs state that the ETs RTOR credits that remain at the end of the

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[72] Midwest ISO TOs IB at 50 (citing November 18 Order 109 FERC ¶ 61,168 at P 66; November 17 Order, 105 FERC ¶ 61,212 at P 9, 14, 45).

[73] *Id.* at 50-51.

[74] *Id.* at 52 (citing November 17 Order, 105 FERC ¶ 61,212 at P 45 n.94).

[75] *Id.* at 58 (citing Midwest ISO and PJM's April 25, 2005 joint filing certifying their readiness to bill and settlement SECA payments to the PJM transmission owners and the Midwest ISO Transmission Owners, Certification Submission, Docket No. ER05-6, *et al.* (Apr. 25, 2005) ("Readiness Filing")).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

transition period expire because at that point, the SECA obligations will have been properly adjusted. *Id.* at 58 (citing Ex. FE-4).

253. AEP/Exelon also argue that the Commission's orders do not require a customer's obligation to pay SECAs and ETs to be capped at the amount of the customer's SECA obligation. AEP/Exelon IB at 16. In fact, AEP/Exelon claim that the Commission did not eliminate T&O rates for ETs because there would be no resulting economic efficiency gains. *Id.* AEP/Exelon contend that Dr. Henderson stated that economic circumstances of the ETs and SECA obligations may not be coincident and a LSE may conduct more business under its ETs than it conducted in the test year used to calculate its SECA obligation. *Id.* AEP/Exelon also argue that the process proposed by PJM and the Midwest ISO for crediting revenues from ETs has been accepted by the Commission and is reasonable. *Id.*

254. Next, AEP/Exelon aver that FirstEnergy's argument that the proposed crediting mechanism is unreasonable and should be rejected. AEP/Exelon RB at 32. AEP/Exelon claim that this is incorrect because the Commission did not limit customer's obligations to pay RTORs under ETs which the Commission intended to continue until either the transaction itself ended or the transition period. *Id.* at 33. In addition, AEP/Exelon claim that although the Commission allows a customer to propose adjustments to its SECA so that it does not pay an RTOR for ETs and SECAs, it implemented no such adjustment for a customer's ETs payments. *Id.* Although Mr. Sprague described the ETs credits as belonging to the customer, AEP/Exelon argue that the statement does not support FirstEnergy's argument that the credit should also reduce a customer's ETs payments by the amount of its SECA charges. *Id.* at 34. Finally, AEP/Exelon request that FirstEnergy's proposal to cap ETs be rejected and that excess ETs revenues received by the Midwest ISO TOs be treated as a backstop to protect it and the other PJM TOs from under recovery of their "lost revenues." *Id.* at 34-35.

255. The Midwest ISO TOs also claim that FirstEnergy's arguments that the ETs charges result in rate discrimination must be rejected as a collateral attack on the Commission's orders and thus outside the scope of this proceeding. *Id.* at 42. In addition, the Midwest ISO TOs contend that FirstEnergy's example used to illustrate rate discrimination is not a valid comparison of similarly situated entities because customers that had transactions before November 17, 2003 are not similarly situated to entities that had transactions after that date. *Id.*

256. Midwest ISO TOs state that contrary to FirstEnergy's, Dayton's and AEP/Exelon's arguments the RTORs for ETs are not a windfall to the TOs or in excess of the Commission's orders directing recovery of the "lost revenues." *Id.* at 43. They assert that ETs revenues are separate from the "lost revenues" associated with the elimination of the RTORs and therefore are not left over amounts that should be used to cover shortfalls in "lost revenues." *Id.* (citing November 17 Order, 105 FERC ¶ 61,212 at P 9). Contrary

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

to FirstEnergy's assertions, the Midwest ISO TOs state that the proposed crediting mechanism is reasonable because, consistent with the Commission's orders, it ensures that customers are not charged both a SECA and RTORs for ETs during the transition period.[76] The Midwest ISO TOs further assert that the treatment of unused credits is just and reasonable since the credits associated with payments made for RTORs for ETs may only be used to offset a SECA obligation and once the transition period ends, there are no more obligations to be offset by any remaining credits. *Id.* at 45.

257. Next, Midwest ISO TOs contend that FirstEnergy's arguments that the SECA obligations as filed rates represent the maximum amount recoverable are incorrect since the collection of RTORs for ETs during the transition period, SECA charges during the transition period and SECA credits for amounts collected for RTOR ETs are all filed rates under the Midwest ISO TEMT.[77] Likewise, the Midwest ISO TOs claim that FirstEnergy's argument that amounts received for the ET RTORs should be credited to the SECA obligations would violate the Filed Rate Doctrine because such arguments disregard the filed rates related to the RTOR service schedules. *Id.* at 45-46.

258. First Energy argues that the Commission determined that a customer's SECA obligation is that customers fair share of the Midwest ISO TOs lost revenues. FirstEnergy RB at 21. Allowing the credits to expire would result in a windfall for the Midwest ISO TOs, FirstEnergy claims. *Id.* Thus, FirstEnergy argues, the Midwest ISO TOs are only entitled to recover the amount of a customer's SECA obligation and not the higher of a customer's SECA obligation or its ETs RTOR charge. *Id.* FirstEnergy notes that it agrees with the Midwest ISO TO's statement that the Commission orders stated that ETs would continue to pay RTORs. *Id.* at 22 (citing Midwest ISO TOs IB at 50). FirstEnergy states that the Midwest ISO TOs stated that the two reasons why the Commission did not eliminate RTORs for ETs was to: (1) minimize the lost revenues to be recovered through the lost revenue recovery mechanism and (2) address the concern of some parties that generators may benefit from the elimination of the RTORs and that those savings may not be passed on to LSEs. *Id.* (citing November 17 Order, 105 FERC ¶ 61,212 at P 14, 45). However, FirstEnergy states, capping a customers' ETs charges at its SECA obligation does not affect the Commission's purposes. *Id.* FirstEnergy states that contrary to the Midwest ISO TOs' contentions, both ETs RTOR charges and SECAs are part of the transitional rate mechanism that was designed to collect the TOs' lost revenues and the Commission left the RTORs for ETs in place only to the extent that

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[76] MISO TOs RB at 44 (citing Midwest ISO TOs IB at 56-58; Ex. RTO-1 at 2; Ex. PJM-1 at 1).

[77] Midwest ISO TOs RB at 45 (citing February 10 Order at ordering para. (B); June 16 Order at ordering para. (A) September 12 Order, 12 FERC ¶ 61,267, at ordering para. (B) October 6 Order, 113 FERC ¶ 61,010, at ordering para. (A) Ex. MTO-189 at 7; Midwest ISO Tariff, Original Sheet Nos. 895, 911, 988-989, 1046).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

such charges amounted to the customer's fair share of the transitional rate mechanism. *Id.* at 23 (citing November 17 Order, 105 FERC ¶ 61,212 at P 9).

259. Capping a customer's ETs charges at its SECA obligation is not a collateral attack of prior orders FirstEnergy asserts, because the continuation of the ETs charges and its proposal to cap such charges are not inconsistent. *Id.* In fact, FirstEnergy claims that if the Midwest ISO's believed that a customer's ETs charges should not be capped it should have filed a request for rehearing or clarification and filed tariff provisions providing for the expiration of the unused ETs credits at the end of the transition period. *Id.* at 24. FirstEnergy claims that the crediting provision for ETs under the Midwest ISO's TEMT does not state that ETs credits will be capped at the entity's SECA obligation or that any unused credit will expire. *Id.* at 24-25 (citing Ex. MTO-51 at 7). Finally, FirstEnergy argues that the Commission's June 16 Order stated that a customer is entitled to a credit for the amount of its ET charges in excess of its SECA obligation, but the Commission did not state that such credits would expire at the end of the transition period or that the Midwest ISO TOs would be entitled to keep the ETs charges that are in excess of a customer's SECA obligation. *Id.* at 25.

260. FirstEnergy also contends that capping ETs charges at a customer's SECA obligation does not eliminate ETs as the Midwest ISO TOs claim, because customer's are responsible for paying the exact amount of their SECA obligations. *Id.* at 25-28. In addition, under the Midwest ISO TO's argument, FirstEnergy claims, the customer would have to pay the higher of its SECA obligation or its ETs charges. *Id.* at 29. This is problematic because the Midwest ISO TOs are only entitled to recover the amount of the customer's SECA obligation, FirstEnergy claims. *Id.* at 29-30. FirstEnergy contends that the Midwest ISO TOs argument that customers under ETs are bound and cannot change their behavior has nothing to do with whether a customer's ETs charges should be capped at a customer's SECA obligation. *Id.* at 30. The customer is obligated to pay its share of the lost revenues via ETs charges, SECA obligations or both, FirstEnergy argues. *Id.* Thus, FirstEnergy claims, capping a customer's ETs charges at the SECA will not require other entities to absorb lost revenue collection short falls since the total amount of the SECA obligation will be paid by either one of both types of charges. *Id.* at 31.

261. FirstEnergy states that it does not disagree with the crediting mechanism employed by the Midwest ISO and PJM. *Id.* at 32. However, FirstEnergy argues that the Midwest ISO's and the Midwest ISO TO's assertion that ETs credits expire at the end of the transition period is not supported by Commission precedent or the Midwest ISO's open-access tariff. *Id.* Thus, customers are entitled to their remaining credits at the end of the transition period. *Id.*

262. Finally, FirstEnergy asserts that there is no support in the Commission's orders for AEP/Exelon's and Dayton's request to use excess ETs credits as a backstop. *Id.* at 33 (citing AEP/Exelon IB at 50; Dayton IB at 28). First Energy claims $20 million of the

approximately $26 million in ETs credits belongs to it. *Id.* (citing FirstEnergy IB at 17-35). There is no Commission order that supports this use of ETs, FirstEnergy argues. *Id.*

Discussion/Findings/Conclusions

263. FirstEnergy is adamant that ETs should be capped at the amount of a customer's SECA obligation. FirstEnergy IB at 17. This contention is incorrect because the Commission has not held that such a cap should be employed. In the November 17 Order the Commission stated that "for existing transactions, we will allow the existing RTOR rate design to remain in effect during the transition period." November 17 Order, 105 FERC ¶ 61,212 at P 9. That same order also stated that "we will not eliminate the RTORs for existing transactions that sink in the combined region…." *Id.* at P 14. The Commission also stated that "any transmission customer that currently has a long-term firm transmission reservation effective before April 1, 2004, including those that are not load serving entities will continue to pay the RTOR, thus limiting the amount of lost revenues to be recovered from load." *Id.* at P 45. Thus, the Commission clearly stated that customers under ETs would continue to pay the RTORs. The Commission recognized that LSEs paying T&O rates for existing transactions may be assessed disproportionate SECA charges and proposed:

> Similarly, we recognize that a LSE with existing T&O service reservations that will continue into the transition period will continue to pay the RTORs. If such an LSE does not have its own sub-zonal SECA, the SECA may assess such LSE a disproportionate share of lost RTOR revenues. Therefore, we will allow such LSEs with existing transmission arrangements that continue into the transition period to demonstrate to the Commission *the extent of disproportionate impact of paying both the RTOR and the SECA* and propose an adjustment to its SECA obligation proportional to the RTOR charges it will continue to incur under the existing transmission arrangements.

Id. at P 45 n.94 (emphasis added). It is clear that the Commission only intended this mechanism to apply to LSEs with ETs which would pay T&O rates and SECA charges. The adjustment proposed would be to the SECAs and not to the T&O rates for ETs.

264. FirstEnergy's arguments attempt to expand the scope of this mechanism to limit the TO's charges for ETs and is thus contrary to the Commission's orders. As a matter of fact, the Commission's pronouncement would adjust the SECA in proportion to the T&O payments that the entity incurs. This is exactly the opposite of what FirstEnergy proposes, which is to limit the ETs RTORs to the SECA obligations. FirstEnergy's contentions are contrary to the Commission's orders and are thus rejected.

265. The June 16 Order does not support FirstEnergy's contentions. That order required

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

billing procedures for crediting ETs. The June 16 Order did not limit ETs RTOR payments. In addition, the June 16 Order did not establish a cap on the amount of ETs T&O charges a customer could be billed and it most definitely did not transform ETs credits into refundable amounts as FirstEnergy asserts. FirstEnergy IB at 23. Such credits exist only to the extent that a T&O ETs' payment exceeds a SECA obligation in a particular month and the ETs payment is carried over as a credit against the SECA for the following month. June 16 Order, 111 FERC ¶ 61,409 at P 41.[78] Moreover, from the Commission's language one can determine that RTORs for ETs and SECA payments were two distinct types of charges for separate transactions.[79] It is found that the amount that a customer can be billed for ETs RTORs should not be capped at a customer's SECA obligation. Accordingly, FirstEnergy's arguments are meritless.[80]

266. The Midwest ISO's and PJM's proposed crediting process is reasonable. Specifically, Schedule 21 of the Midwest ISO TEMT and Attachment X of the PJM Tariff provide for customers to receive credits for RTORs paid for ETs.[81] In addition, the record indicates that the Midwest ISO and PJM also carried excess ETs credits forward to offset SECA payments in future months.[82] As discussed above, the fact that the credits expire or are not refunded at the end of the transition period is irrelevant.

Issue 3.B.3: Whether the Boroughs of Lansdale, Blakely, Catawissa, Duncannon, Hatfield, Kutztown, Lehighton, Middletown, Mifflinburg, Olyphant, Quakertown, Royalton, St. Clair, Schuylkill Haven, Watsontown and Weatherly, Pennsylvania should be excluded from SECA charges due to firm power requirements contracts that existed during the test years but made no explicit statement regarding the location of the generation that supplied power under those contracts?

267. This issue was resolved by settlement is thus considered moot. AEP/Exelon RB at 35.

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[78] Thus, although it may not be completely accurate to say that any unused credits expire at the end of the transition period, the same result occurs because there is no longer a SECA obligation for ETs credits to offset. FirstEnergy's arguments that these credits should not "expire" are rejected since the Commission only intended the credits to remedy the billing disparities. *See* November 17 Order, 105 FERC ¶ 61,212 at P 45 n.94.

[79] *See id.* at P 14; June 16 Order, 111 FERC ¶ 61,409 at P 32.

[80] No refunds are due for excess credits that remain after the transition period, and thus no associated interest.

[81] *See* Ex. MTO-148 at 7, PJM Tariff, First Revised Sheet No. 545D.

[82] *See* Readiness Filing at 3.

Issue 3.B.4: Should the PJM RTOR rate for transactions exiting PJM via the ComEd zone be credited to an effective rate of $1.00/kW and, if not, what should the rate be?

268. This issue was resolved by settlement and is considered moot. AEP/Exelon IB at 17.

Issues 1.C. and 3.C. (OATi Tag Data and Zones/Sub-zones)

A. Issue 1.C. Is the analysis of OATI tag data to identify, and to allocate a SECA responsibility to, importing zones or sub-zones adequately supported?

B. Issue 3.C. Zone/Sub-zone:

1. Are the proposed zones and sub-zones appropriate?

2. For each TO, is the method for developing a transmission rate to derive the SECA obligation of each zone or sub-zone appropriate?

3. Has Alleghany Power demonstrated that it should be a separate sub-zone for the entire transition period?

Compliance Filings

269. The Midwest ISO TOs used the OATi tag data to develop sub-zones and the SECA charges for sub-zones to be assessed on entities in the Midwest ISO to recover the lost revenues claimed by the PJM TOs. Specifically, the Midwest ISO TOs assigned as sub-zones within each zone the OATi tag data with specific sink codes. They reviewed 2002 and 2003 OATi tag data to identify the transactions exiting PJM and sinking in the Midwest ISO zones. Midwest ISO TOs IB at 59-60. A sub-zone was established for each entity that was identified through analysis of the OATi tag data for the 2002 and 2003 test years as the sink, with the identified MWhs assigned to that sub-zone. Due to the fact that an entity could have multiple sink codes, the Midwest ISO TOs assigned the sink codes to the appropriate sub-zones. Several adjustments were made within Ameren, ATSI, Cinergy, AmerenIP, METC and Otter Tail zones.[83] The sub-zone charges are reflected in Schedule 22.

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[83] In Ameren and AmerenIP zones, where the OATi tag data did not always reflect a specific sink, these entities used their internal scheduling data to reassign MWhs to the proper sinks; in the ATSI zone certain transactions reflected invalid sink codes for MSG and PJM and other information was used to reassign the MWhs to the correct sub-zone; Cinergy used its retail settlements data base to assign the MWhs to each retail

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

270. The Midwest ISO TOs set forth their lost revenues in Schedule 21. Ex. MTO-148 at 1. Those lost revenues are to be collected pursuant to sub-zone charges developed by the PJM TOs and stated in the PJM open-access tariff. Midwest ISO TOs RB at 30. The Midwest ISO TOs also included a default collection provision for the purpose of allocating lost revenue obligations in case the PJM TOs did not file sub-zone charges. However since the PJM TOs filed sub-zone charges to recover the Midwest ISO TOs' lost revenues, the default provisions were never implemented. *Id.* (citing Ex. MTO-1 at 17:12-14).

271. Dr. Henderson developed zonal SECA obligations to be recovered by the Midwest ISO to compensate PJM TOs for their lost revenues. He also developed zonal and sub-zonal SECA obligations to compensate PJM TOs for their lost revenue claims against one another (intra-PJM SECA obligations). AEP IB at 32. The OATi tag data was used to identify the importing zones. The SECA obligation in each zone or sub-zone was developed by multiplying the average rate of each TO by the amount of MWh it delivered to that zone or sub-zone, and aggregating the obligations to the TOs. Ex. PTO-23, 27, 41, 45, 60 and 63. The sub-zones created for AEP, ComEd, Dayton and Dominion reflect LSEs identified on the OATi tag data as being served by energy imported over the system of a transmission provider within the Combined Region other than the LSEs host transmission provider. No sub-zones were proposed for the Classic PJM zone since it is not possible to create sub-zones with the OATi data for the Classic PJM. The SECA obligations owed to the Midwest ISO TOs and the Intra-PJM SECA rates are described in Attachment X of the PJM Tariff. AEP IB at 32.

Parties' Contentions

272. The Midwest ISO TOs argue that the use of OATi tag data to identify sub-zones in the Midwest ISO to recover the PJM TOs' claimed lost revenues complies with the Commission's Orders and is adequately supported. Midwest ISO TOs IB at 12. The Midwest ISO TOs argue that their calculations are supported by spreadsheets, which include a full set of NERC OATi tag data summarizing the MWhs each TO transmitted that sank in each zone in the Combined Region during 2002 and 2003 calendar years. *Id.* at 13 (*see* Ex. MTO-14, Ex. MTO-38). Specifically, the Midwest ISO TOs filed exhibits depicting the analysis of the NERC OATi tag data to identify the lost revenues of the Midwest ISO TOs and the allocation of the responsibility of the lost revenues to the various zones in the PJM region. *See* Ex. MTO-104 to MTO-147; Ex. MTO-190.

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supplier; METC individually cross-referenced each OATi tag for each day against customer billing schedules or used other information on the OATi tags to assign the sink codes; in Otter Tail the sink codes for Minnkota, were removed since it is not a Midwest ISO member.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

273. The Midwest ISO TOs contend that the proposed zones and sub-zones are appropriate, just and reasonable. Midwest ISO TOs IB at 60. The Midwest ISO TOs assert that the lack of ultimate sink data within Classic PJM does not alter the Midwest ISO TOs total lost revenues allocated to "Other PJM Entities" nor represents a flaw in the OATi tag data analysis. *Id.* at 13. The Midwest ISO TOs further claim that the Commission has recognized that certain transactions may not be traceable to load because of the PJM spot market. *Id.* (citing July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 54). The Midwest ISO TOs reject BGE's claims that the data processed by Mr. Heintz have not been tested nor the steps verified. In response, the Midwest ISO TOs assert that BGE, other parties and the Commission have had access to Mr. Heintz's workpapers and the OATi tag data, and over a year to analyze the OATi tag data and Mr. Heintz's analysis set forth in his workpapers or to ask Mr. Heintz to explain his calculations. *Id.* at 14-15.

274. AEP/Exelon state that they have adequately supported the analysis of OATi tag data to identify and allocate SECA responsibility to importing zones or sub-zones reflected in the PJM TO's compliance filings. *Id.* at 12. AEP/Exelon reject the arguments concerning the general reliability of OATi tag data asserted by BGE. AEP/Exelon argue that such concerns were already addressed by the Commission in the November 17, 2003 Order on Rehearing at P 84 where the Commission directed the Classic PJM TOs to address alternative methodologies for evaluating the relative benefits from import transactions between the various zones of the Classic PJM region. AEP/Exelon RB at 10 (citing November 17 Order, 105 FERC ¶ 61,212 at P 84).

275. AEP/Exelon maintain that the creation of sub-zones is consistent with the Commission's orders and generally should be approved. AEP/Exelon IB at 9. However, AEP/Exelon contend that the creation of sub-zones within the ATSI zone of the Midwest ISO may not be appropriate in light of the under collection of the lost revenues allocated to the ATSI zone. *Id.* at 17. The Midwest ISO's failure to track the activity of retail electric suppliers through retail ticketing, raises significant concerns. *Id.* AEP/Exelon aver that the Midwest ISO TOs allocated $31,599,161 of the total ATSI zonal SECA obligation to the Green Mountain sub-zone, and the Midwest ISO has not collected any of it. AEP asserts that its share is $10,037,319, ComEd's share is $1,179,954 and the Classic PJM TO's share is $1,930,655. *Id.* at 49. AEP/Exelon argue that the Commission must decide who is responsible for paying the SECA obligation for the Green Mountain sub-zone.[84]

276. AEP/Exelon also urge the Commission to consider requiring the Midwest ISO TOs to provide a "backstop" for payment of these amounts owed to AEP/Exelon from the

[84] Green Mountain's sub-zone issues are addressed below.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

approximately $26 million in ETs revenues received by the Midwest ISO TOs in excess of their lost revenue amounts. *Id.* at 49-50. AEP/Exelon state that the sub-zones proposed for the AEP, ComEd, Dayton and Dominion zones reflect LSEs that were identified on OATi tags as being served by energy imported over the system of a transmission provider within the Combined Region other than the LSE's host transmission provider. *Id.* at 32.

277. Ormet asserts that placing it in its own sub-zone is unduly discriminatory and preferential. The Ormet sub-zone is the only sub-zone in the AEP zone restricted to a single end-use customer. Ormet argues that under the proposed rate design, its SECA costs far exceed its benefits from seams elimination, and under the circumstances, it would be appropriate to alter the proposed Ormet sub-zone. Ormet IB at 5. Ormet recognizes that the Commission has ordered sub-zones, but in light of the record developed in this proceeding, suggests that the Presiding Judge recommend a zonal approach and broader allocation of SECA costs. *Id.* at 6, 19, 72.

278. AEP/Exelon argue that placing Ormet in its own sub-zone is fair, appropriate and economically efficient in light of Ormet's unique characteristics. AEP/Exelon IB at 33-34. According to these entities, Ormet's position is a collateral attack on the Commission's orders which require that the calculation of SECAs be on a sub-zonal basis unless all of the sub-zones within a zone agree otherwise. AEP/Exelon RB at 35 (citing November 17 Order, 105 FERC ¶ 61,212 at P 86). AEP/Exelon reject Ormet's proposal for the establishment of a single PJM-wide SECA, or elimination of the sub-zones within the AEP zone. If Ormet's proposal is adopted, the SECA charges for every native load customer of AEP would increase substantially. AEP/Exelon assert that this is contrary to cost-causation and rate design principles, as well as the Commission's rationale in approving SECA sub-zones. AEP/Exelon IB at 32.

279. FirstEnergy takes no position with regard to Ormet's claim regarding its sub-zone. However, FirstEnergy argues that Ormet's requested relief, to eliminate sub-zones within the PJM zone or merge the sub-zones within AEP into one sub-zone, should be denied. FirstEnergy asserts that Ormet's request is a collateral attack on the Commission's orders and beyond the scope of this proceeding. FirstEnergy RB at 36.

280. The SECA rates for the FirstEnergy zone in PJM for January 1, 2005 through March 31, 2006 were calculated by dividing the Midwest ISO SECA obligation allocated to the FirstEnergy zones by the 2004 zonal peak load for the FirstEnergy zones. *See* Ex. FE-1 at 8:22-9:6. The FirstEnergy zonal peak load for 2003 and 2004 was determined on the basis of the ratio of FirstEnergy's zonal peak load to the sum of the zonal peak loads for all of the TOs. See *Id.* at 8:1-8. FirstEnergy contends that this testimony is unchallenged in the record. FirstEnergy IB at 16-17.

281. BGE argues that the use of OATi tags is unreliable and inadequate for the purpose

of providing an estimation of the transactions formerly subject to RTORs that sank within the PJM-Midwest ISO footprint. BGE IB at 25 (citing Ex. CTO-4 at 16: 17-18). BGE asserts that the OATi tags fail to perform their prescribed role in the calculation of SECA zonal and sub-zonal charges. For example, it is not possible to create sub-zones within the Classic PJM because PJM operates as a single control area and OATi tags do not identify sink loads within PJM. *Id.* at 25-26. BGE also points out that Congress was troubled that the SECA lacks "a clear accounting of actual costs or proper allocation." BGE RB at 12 (citing 151 Cong. Rec. H 9813, 9911-12 (daily ed. Nov. 7, 2005)).

282. AEC/SMECO argue that using OATi tag data is not adequately supported because such data does not provide cost causation information for entities in the Classic PJM zone, such as AEC and SMECO. AEC/SMECO IB at 14-15. Entities in the Classic PJM region have the SECA charges and resulting lost revenue allocations based generally on the amount of load served in the Classic PJM region without regard to each Classic PJM transmission user's specific use of resources that crossed the seam within the Combined Region. *Id.* Since the specific usage of entities in Classic PJM is unknown, AEC/SMECO assert that there is no evidence that the costs are allocated in proportion to usage; and thus, the proposed SECA rate designs and resulting lost revenue allocations and rates are unjust and unreasonable. *Id.* at 15-18. They assert that the method used for imposing SECA charges is unfair because for some entities it was based on OATi tag data, while for the "Other PJM LSEs" the SECAs were based on the ratio of their load divided by the load of all entities that are lumped together in a zone. *Id.* at 34.

283. AEC/SMECO argue that the imposition of SECA charges on a zonal basis to LSEs that did not import power across any relevant seams to serve load is improper. AEC/SMECO contend that they should not be required to pay a SECA because neither AEC nor SMECO paid a RTOR, used or benefited from the transmission facilities and further, no TO is seeking a SECA from them. *Id.* at 26-27. Even if they were assessed a SECA, AEC/SMECO maintain that the record demonstrates that the sub-zonal charges to AEC and SMECO would each be zero. *Id.* at 19.

284. Quest/ESI and Strategic argue that AEP's suggestion of eliminating the sub-zones in the First Energy/ATSI zone should be rejected. Quest/ESI and Strategic argue that spreading Green Mountain's $32 million SECA responsibilities to other LSEs in the zone would violate cost causation principles, constitute retroactive ratemaking and result in unjust and unreasonable charges. For similar reasons, Quest/ESI and Strategic disagree with AEP's suggestion that any excess collection of SECA should be applied against amounts owed by Green Mountain. Quest/ESI and Strategic RB at 24-27.

285. Green Mountain argues that the OATi tag data is not reasonable and reliable and the allocation of cost responsibility based on this data violates cost causation principles. Green Mountain IB at 7-9. It also objects to having been identified as a sub-zone because it never purchased T&O transmission service.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

286. Wolverine argues that the Wolverine sub-zone is appropriate and requests approval of the Wolverine Power Marketing Cooperative sub-zone (Wolverine sub-zone) in the ITC pricing zone. Wolverine states that its sub-zone is included in the list of zones and sub-zones found in Schedule 22. Wolverine further claims that its position is supported by the exhibits and testimony of Mr. Heinz. *See* Ex. MTO-92 at 32, 40 and MTO-189 at. Wolverine avers that no one opposes the Wolverine sub-zone. Wolverine IB at 2-3.

287. Dominion argues that the sub-zones of the Dominion zone are appropriate. Dominion IB at 18.

288. AMP-Ohio requests the identification of individual sub-zones within the AEP zone. AMP-Ohio alleges that certain problems exist with the manner in which its members were aggregated into sub-zones. *See* Ex. AMP-1 at 11. Grouping all of the sub-zones within one sub-zone had the effect of creating an average SECA rate for all of them. According to AMP-Ohio, creating a unique sub-zone for each municipal or group will assure that one municipal or group of municipals will not be assessed a SECA based upon the loads and power supply selections of others. AMP-Ohio IB at 39-40.

289. Notwithstanding the Certain Classic PJM TOs opposition to the SECA mechanism, they reject AEC/SMECO's assertion that no portion of the SECA responsibility allocated to the loads in the PJM Classic zones should be apportioned to AEC and SMECO. For instance, they argue that AEC/SMECO did not provide evidence that their supplier was required to provide the MWh consumed by the loads with in-zone generation. Additionally, they argue that AEC/SMECO which had loads served in the Allegheny Power (AP) sub-zone received the benefits of the settlement dealing with the creation of the AP sub-zone. Finally, these entities argue that the remedies sought by AEC/SMECO would unfairly shift costs to other loads within Classic PJM zones. Certain Classic PJM TOs RB at 6-7.

Discussion/Findings/Conclusions

290. The Commission determined that the SECA should be charged on a sub-zone basis. The SECA is designed to collect revenue from each zone, or sub-zone, in proportion to the benefits that the load within the zone, or sub-zone will realize when it no longer has to pay pancaked rates for the transmission purchased from transmission owners in the RTO to serve its load. The Commission found that with charges on a sub-zone basis, the benefits of eliminating rate pancaking are more closely aligned with the associated lost revenues so that load will not be significantly burdened by the transition to a common market. November 17 Order, 105 FERC ¶ 61,212 at P 85. The SECA charges were to be done utilizing OATi data. *See* i*d*. at P 67.

291. There was recognition that sub-zone SECAs may be difficult to administer and

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

customers will have to balance the benefits of creating sub-zonal SECAs against the difficulty in administering the SECA on a sub-zone basis. Thus, the Commission stated it would accept calculation of the SECA on a sub-zonal basis unless all the sub-zones within a zone agree otherwise. *Id.* at P 87. The Commission noted that if the SECA is calculated on a zonal or sub-zonal basis, the overall cost responsibility for the zone should remain the same. *Id*. at P 86.

292. The Commission directed the Midwest ISO to consult with customers regarding "calculating the SECAs on a zonal or PJM-wide basis." *Id.* at P 51. If the customers agree, then the Midwest ISO may file a SECA on a PJM-wide basis. Otherwise, MISO and PJM should work together so that Midwest ISO can provide the data on a sub-zonal basis. *Id.* at 51.

293. The Commission further directed "the RTOs and their transmission owners to provide supporting documents containing calculations and data, including NERC e-tag data used, and detailed narrative descriptions of all adjustments to data and calculations performed, to develop the proposed SECAs." February 10 Order, 110 FERC ¶ 61,107 at P 38; *see also* June 16 Order, 111 FERC ¶ 61,409 at P 37 n.12.

294. In addition, SECAs are to be "[c]onsistent with the principle of cost causation…." The load of an importing utility should pay a fair share of the costs of the exporting utility's transmission facilities for its use of those facilities. *Id.* The lost revenue recovery mechanisms are calculated based on the revenue recovered through the just and reasonable rate charged in a historical period for T&O service and will approximate the exporting utility's cost of providing service to the importing utility's load. *Id.* The allocation of SECA charges should be tied to "the proportion of benefits that such customers will receive from the elimination of the unjust and unreasonable rate design…." *Id.* at P 9.

295. The Commission also found it necessary to "evaluate the resulting rates to ensure that the mechanism produces a reasonable result." July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 54 n.85. "The Commission opted to not render a decision on any particular methodology without the actual rates before it." *Id.*

296. The record in this case establishes that OATi tag data cannot be used to create sub-zones in the Classic PJM zone. Mr. Bourquin testified that PJM maintains an advanced, highly liquid energy market that is independent of actual flows, and consequently, it has no need for, and does not use, this NERC or OATi tag data to track physical activity that occurs within PJM's borders. Typically, once energy is delivered into PJM, it is indistinguishable from any other energy that may be sold into the PJM spot market or transactions that are specifically designated for deliveries outside the footprint. Even in this latter situation, the actual exports by necessity cannot be traced to any particular source without undermining the principle of liquidity upon which the PJM market

operates. Put simply, as Mr. Bourquin, a licensed professional engineer, has affirmed, "it is not possible to determine from e-tag data the ultimate sinks for deliveries of energy into PJM." Ex. CTO-4 at 16:19 – 20. The *quid pro quo* for an integrated, pancake-free, seamless market in PJM is that contract flow-based data becomes obsolete and is not maintained from source to sink. That has never been a concern, and indeed cost savings are realized by not attempting to tag flows.

297. Additionally, Mr. Bourquin further testified that absent (1) this detailed OATi tag information, (2) all market-participants' contract data, and (3) a way to allocate spot market suppliers for everything that transpires within the entire PJM RTO, it is not possible to determine what loads used energy from which sources. There is no way of telling what control zone bought transmission capacity for energy, let alone which retail choice supplier or LSE within a control zone bought transmission capacity, or which reservation was used to supply any control zone. Tags from the mid-West into PJM typically tag "PJM" or its border-entry point as the sink without further identifying the destination within PJM, or whether the energy leaves PJM for another destination. Ex. CTO-4 at 13:4-6. Although energy is always balanced in the aggregate, PJM has several hubs from which energy is exchanged without trace. PJM's market is essentially a liquid market, much like a commodity exchange. *Id.* at 13:13-18. "The liquidity of the spot market allowed AEP and others, such as Midwest ISO TOs, to effectuate transactions that are untraceable by OATi tags once they got the power into PJM. These entities are now benefiting from the partial tracking afforded by the tag information to draw faulty inferences that PJM was the sink in order to drive up the SECA." *Id.*

298. In addition, Mr. Borquin maintained that use of OATi tags are unreliable and are hopelessly inadequate for the purpose of providing "an estimation of the transactions formerly subject to RTORs that sank within the PJM-Midwest ISO footprint." Ex. CTO-4 at 16:17–18. Some OATi tags are not completely filled out. To the extent that they give any information, most of these tags simply show that deliveries were made to PJM, but not which control zone, and not which transmission zone, let alone which LSE. These tags do not typically identify who is the recipient other than PJM. Some of the OATi tags that were submitted are duplicates, which leads to the suspicion that some transactions are being double counted in the tally of lost revenues. Mistakes made in compiling OATi tags, including lost tags, and clearly erroneous tags which describe transactions that were disproved by other TO records. As Mr. Bourquin observed, there is no indication "whether a nominal sink was really a mid-way point to a further delivery control area." Ex. CTO-4 at 10:15–16.

299. The lack of reliable OATi tag information and "difficulty in matching tag data" (Ex. CTO-4 at 11:5) makes it impossible to comply with the Commission's requirement to allocate lost revenue responsibility among PJM zones, or even smaller sub-zones. Moreover, the tags marked "PJM" in many cases merely recorded transactions that were passing through PJM. For example, for energy to go from AEP to New York, it first

enters PJM. If AEP tagged 100 units to PJM's Western Hub, and also tagged 80 units to New York from the Western Hub and 40 units to Carolina Power & Light from the Western Hub, it would be impossible to tell if some or all of these 100 units were hubbed out of PJM or not. PJM's spot market does not track the source to the sink of its transactions.

300. Mr. Bourquin's testimony is given significant weight. Additionally, BGE asserts that the processing of the OATi tag data done by Mr. Heintz and the accuracy of such data has never been tested. Summaries have been provided but there is no way for the Commission or the parties to follow the steps that led up to the conclusions that Mr. Heintz gives. While the underlying data can be obtained, it would require literally tracking piece by piece each transaction that occurred in all of the affected areas for the entire test period. Nobody has yet undertaken that monumental verification task. Without doing so, it is impossible for anyone, including the Commission Staff, to confirm the accuracy of the aggregate numbers upon which the SECA calculations are based. Even Mr. Heintz admitted that "it would be almost impossible to calculate the actual transmission charges paid directly or indirectly by any given load." Ex. MTO-1 at 25:1-2.

301. The record in this case supports the finding that parties have not independently verified the accuracy of the data. However, parties have identified transactions that were incorrectly included. Therefore, some type of cross checking of the data has taken place. The Commission decided that this is the data that would be used in this proceeding. Alternative methodologies were not provided. The findings above concerning the test periods, lost revenues and rate design, coupled with the recommendation below, mitigate any anomalies from the use of this data.

302. Costs should be allocated to customers in a way that reflects the costs of providing transmission services to those customers. *See PJM Interconnection L.L.C.*, 116 FERC ¶ 63,007 at P 237 (2006) *citing Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, FERC Stats. & Regs ¶ 31,005 at 31,144 (October 26, 1994) (*Transmission Pricing Policy Statement*). Commission precedent indicates that "cost causation and received benefits are two methods of expressing the same concept." *California Indep. Sys. Operator, Corp.*, 103 FERC ¶ 61,114 at 61,357 (2003), *reh'g denied*, 106 FERC ¶ 61,037 (2004). In *KN Energy, Inc.*, the D.C. Court of Appeals stated that the received benefits cost allocation was another method of cost causation, and simply an extension of the chain of cost causation. *KN Energy*, 968 F.2d 1295, at 1302. In *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004), the Court of Appeals also found that cost causation principles compare the costs assessed to benefits drawn or burdens imposed. 373 F.3d at 1368. Commission precedent holds that in order for benefits based cost allocation to occur the benefits must not be "insubstantial,

limited or purely speculative." *California Indep. Sys. Operator Corp.*, 113 F.E.R.C. ¶ 63,017 at 65,125 (2005) (citations omitted).

303. The SECA allocation to entities in the Classic PJM region, set forth in the compliance filings, is unjust, unreasonable and discriminatory. For entities in the Classic PJM region the SECA obligations are based on a load ratio without regard to each LSEs use of the other RTO system. The SECA calculations for the Classic PJM entities were based on the ratio of their load divided by the load of all entities that are included together in a zone defined as "Other PJM LSEs." Due to the fact that the OATi tag data cannot identify specific sinks within PJM, allocation of SECAs within PJM was not based on a sub-zonal basis. The rest of the PJM zones were allocated SECAs based on the OATi tag data. The lack of a reliable mechanism to establish sub-zones within PJM makes the compliance filings contrary to the Commission's requirements that "the load of an importing utility should pay a fair share of the costs of the exporting utility's transmission facilities for its use of those facilities." November 17 Order, 105 FERC ¶ 61,212 at P 48. The record demonstrates that the proposed sub-zonal cost allocation filings fail to properly allocate charges consistent with cost causation and benefit derivation, and as a result did not comply with Commission requirements.

304. AEP witness Bethel stated that he did not take into consideration the benefits any particular sub-zone would expect to receive from the elimination of RTORs. Tr. at 2160:23-61:20. Dr. Henderson stated that the TO's did not need to trace benefits to sub-zones when creating sub-zones. Tr. at 1255:13-25. This is further evidence that the sub-zones allocations were not done in compliance with cost causation principles. It is found this violates Commission requirements that benefits be closely aligned with lost revenues.

305. AMP-Ohio provides another example of cost shifts created by the sub-zone allocation in the compliance filing. The AMP-Ohio municipalities were aggregated in one-sub-zone and allocated costs based on an average rate. This results in SECAs being assessed on the municipals based on the loads and power supply selection of others.

306. Ormet is another example of the anomalies created by the sub-zone allocations in this proceeding. Under the proposed SECA, a zone or sub-zone that did not enter into transactions outside its zone during the test period does not have a SECA obligation, regardless of its usage during the transition period. However, this entity would benefit from transactions it would enter into during the transition period as a result of the elimination of RTORs (reduced costs through access to more suppliers). The Commission anticipated that the SECA charges would recover lost revenues from those transmission customers who will benefit from the elimination of rate pancaking; but LSEs that may not have used any through and out service during the test period, but acquired substantial out of zone service during the transition period pay little or nothing for the benefit of pancake elimination, particularly if that LSE is in its own zone. In contrast, loads like Ormet's, which had a reduction in load during the transition period

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

and thus potentially did not benefit from elimination of the RTORs, are forced to pay a SECA based on service taken and rates paid during the test period. Thus, when applied to actual load, the proposed SECA shifts substantial costs from those entities actually purchasing power in the region during the transition period. Ex. ORM-2 at 16:17-17:4. Dr. Henderson admitted that even though all load benefits from the elimination of RTORs, the use of sub-zones could result in payments by LSEs which imported a substantial amount during the test period but nothing in the transition period. Tr. 2173:24-75:2.

307. The sub-zones created by AEP punish Ormet and other retail choice customers who chose to leave AEP and took advantage of competitive opportunities in 2002 and 2003. Ormet did not receive benefits from the elimination of RTORs which would justify the enormous differential between Ormets SECA rates and the SECAs of the other AEP native load customers. Especially in light of the fact that Ormet did not import power from the Midwest ISO after December 31, 2004 and its load was an average of 8MW during the transition period.

308. Ormet contends that the proposed sub-zone for Ormet fails to comport with the Commission's comparability doctrine. For instance, FirstEnergy and Strategic, which served AEP retail choice customers, are similarly situated to Ormet (they obtained power from outside the AEP system and paid RTORs to other TOs). However, these two entities were grouped together for SECA and pay a much lower SECA than Ormet $634 to$1285 per MW-mo. Ex. ORM-2 at 55:4-7. Additionally, a West Virginia based aluminum smelter that competes with Ormet and is an AEP native load customer will be charged $75 to $91 per MW-mo.

309. Ormets's SECA is $11 million for 2002 and $4.7 million for 2003. The proposed Ormet SECA rate ranges from $1329-$22,187 per MW-mo and the "effective" Ormet SECA rate actually ranges from $4,170 to $50,068. Ormet RB at 28-32. Ormet argues that it is the only individual end-use customer placed in its own sub-zone by AEP. AEP maintains it is appropriate to place Ormet in its own zone given Ormet's unique characteristics: (i) Ormet was not a retail customer; (ii) Ormet is not within the certified service territory of AEP; and (iii) Ormet imported most of its power supplies from the wholesale market through an energy manager by using back-to-back supply arrangements and (iv) Ormet's load was dynamically scheduled by ComEd, so instantaneous changes in Ormet's load did not affect AEP's system. AEP/Exelon RB at 33.

310. Contrary to AEP/Exelon's argument, the fact is that Ormet reduced its load during the transition period. Ormet did not import any power after December 31, 2004 and power was not dynamically scheduled by ComEd after April 2004. Ex. ORM-1 at 4:11-5:23. Because Ormet is in a sub-zone by itself, it cannot benefit from the diversity of load common to other sub-zones and rather must bear the entire burden of its load reduction, even though no transmission revenues were actually lost as a result of the load

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

reduction. Ex. ORM-2 at 56:10-12. The benefit of diversity is that if one industry closes, another may take its place or load growth may make up the difference. *See* Ex. ORM-2 at 54-58. If Ormet is placed in the AEP sub-zone, the resulting increase in the rate for the AEP sub-zone is minimal by comparison to the proposed SECA rate for Ormet of up to $50,068/MW-mo. The AEP-East sub-zone rate is approximately $90.84/MW-mo. Even if all the zones were eliminated, the rate for the AEP zone LSEs would increase to no more than $142.19/MW-mo. Ormet RB at 30-31. The record establishes that it is unduly discriminatory to segregate Ormet in its own sub-zone. This is not consistent with cost causation principles.

311. The record as developed does not support a finding that use of sub-zones produces just and reasonable results. First, it creates unjust, unfair and preferential results in the PJM zone as between the Classic PJM and the New PJM. This is due to the fact that sub-zones could not be created in the Classic PJM and the allocation into this zone does not comply with cost causation principles. Consequently, cost shifting occurs between the Classic PJM and the New PJM. Second, the allocation of SECAs to sub-zones created unfair results, the primary example being Ormet. Therefore, it is found that the compliance filings produced unjust and unfair rates. As a result, it is concluded that the compliance filings did not comply with Commission rules and must be rejected.

312. The Commission provided the option to the entities to collectively determine whether their SECAs should be calculated on a zonal, or sub-zonal basis and directed the Midwest ISO and PJM to consult with the customers in the other RTO as to whether they want their SECA calculated on a zonal or sub-zonal basis. November 17 Order, 105 FERC ¶ 61,212 at P 87. The parties did not agree to a comprehensive solution of this issue.

313. The record in this case establishes an alternative approach which may result in a more equitable allocation of SECA charges. To remedy the sub-zone problem, the sub-zones could be eliminated. As with a proposed rate design, it is also necessary to "take into consideration the effect" of the proposed cost allocation method "on all parties to avoid undue discrimination or preference." *See Dominion Transmission, Inc.*, 105 FERC ¶ 61,350 at P 15 (2003). By eliminating sub-zones, as Ormet recommends, cost causation considerations will be addressed. Ormet asserts that if the sub-zones within the AEP zone were eliminated, the proposed SECA rate to all LSEs in the AEP zone would range from $103 to $159 per MW-mo.

314. As stated by Mr. Russell in ORM-2 at 58-61, the benefits of a combined zone that would have no end-use customer sub-zones include:

- avoid rate shock, and the resulting rate would be low enough not to push load serving entities out of business;

- eliminate the issue of collecting the SECA not paid by entities no longer in business;

- a rate would also be low enough not to interfere with the development of the region-wide energy market, and it would not provide an incentive for utilities to either increase or decrease their loads;

- practical, transparent and simple to implement; and

- significantly diminish the amount of dollars to be adjusted for known and measurable differences.

315. For reasons stated above, one combined zone with a single "footprint" SECA for PJM and Midwest ISO, as a combined zone will alleviate concerns of preferential treatment between PJM and Midwest ISO, as well as allocation issues. Therefore, based on the record, it is recommended that one combined zone be used in the next compliance filing.

316. Should the Commission reject the recommendation for one combined zone, two separate zones, one PJM and one Midwest ISO, is the next best option based on the record in this proceeding. Under this alternative, there is also no end-use customer sub-zones, and therefore this would mitigate anomalies. Furthermore, combined with the findings above, this should resolve a number of problems in the compliance filings. Therefore, based on the record, separate Midwest ISO and PJM zones is an appropriate, just and reasonable alternative. While the alternative option is not perfect, it has the potential to allocate SECAs in a more fair manner than that proposed in the compliance filings. These proposals alleviate the problems of allocating costs proportionate to benefits received and costs causation principles. These approaches seem to result in a more reasonable allocation of costs to all entities.

317. Based on the finding that there should only be one zone (alternatively two zones), arguments on the issue of particular sub-zones are moot. However, should the compliance filings, which established sub-zones, be accepted, then individual sub-zones are appropriate for Wolverine and AMP-Ohio.[85] If the Commission rejects the

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[85] AMP-Ohio (Glouster, Jackson, JV4 Meter Point, St. Marys), Columbus, Dover, OMEG, Orrville, Shelby, Westerville, and Woodsfield. Creating a unique sub-zone for each municipal or group will assure that one municipal or group of municipals will not be assessed a SECA based upon the loads and power supply selections of others. AMP-Ohio I.B at 39-40. AMP-Ohio states that it will work with AEP and PJM to identify deliveries to these sub-zones based on the existing tag and other data. AMP-1 at 12.

recommendation to eliminate sub-zones and accepts the compliance filing as filed, then the Ormet sub-zone should be eliminated based on the findings above. This would entail a zone consisting of AEP, its retail and wholesale requirements customers and its former retail customers (Ormet and Ohio Retail Choice customers).

Issue 3.C.3 : Has Allegheny Power demonstrated that it should be a separate sub-zone for the entire transition period?

318. The AP sub-zone issue is deemed resolved pursuant to a contested partial settlement (Settlement) certified to the Commission on May 11, 2006. *See Midwest Indep. Transmission Sys. Operator, Inc*., 115 FERC ¶ 63,031 (2006).

Issue 3.D: Hubbing Adjustments:

1. For each proposed hubbing adjustment (including cascading hubbing), is the transaction appropriately shifted?

Parties' Contentions

AEP/Exelon

319. AEP/Exelon believe that certain proposed hubbing adjustments have become moot as a result of the settlements that have already occurred in this proceeding. AEP/Exelon IB at 18. Specifically, the settlements between the PJM TOs and Consumers Energy have mooted the hubbing adjustment proposed by Consumers Energy Witness, Mr. Gaarde. *Id.* Similarly, the settlement between AEP and DTE has mooted the hubbing adjustment proposed by DTE. *Id.*

320. AEP/Exelon supports and requests that the Commission approve the proposed hubbing adjustment for generation-only control areas, as implemented by Dr. Henderson on behalf of Duke Energy North America (DENA) and Allegheny Energy (Allegheny). *Id.*

321. Mr. Bethel adds additional adjustments to account for "Out-In" revenues. AEP/Exelon IB at 14. Aware that transactions sinking outside of the Combined Region are to be removed from the SECA calculations, Mr. Bethel notes that some of these transactions actually re-entered and ultimately sank in the Combined Region. *Id.* For instance, in determining 2002 T&O revenues, Mr. Bethel added revenues associated with transactions involving the delivery of energy that first exited AEP at non-Combined Region interfaces and then re-entered and sank within the Combined Region. *Id.*

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Baltimore Gas & Electric Company

322. BGE maintains that hubbing adjustments are the responsibility of the SECA applicants, subsequently arguing that the applicants' compliance filings must be rejected for failing to include such adjustments. BGE IB at 10.

323. BGE criticizes Mr. Heintz for failing to include hubbing adjustments in his analysis and instead passively waiting for other parties to recalculate SECA based on these required adjustments. *Id.* at 10; BGE RB at 15. BGE believes that Mr. Heintz went so far as to admit his non-compliance with the Commission's directive by failing to make hubbing adjustments despite his understanding that such adjustments were required. BGE RB at 13-14.

324. BGE faults Mr. Heintz for failing to exclude from the SECA calculations certain transactions that he identified as having left the Combined Region merely because he was unsure whether these transactions would subsequently re-enter the Combined Region. BGE RB at 14. In response, BGE emphasizes that if the POD is outside the Combined Region, then that transaction is not within the prescribed category of transactions with both a source and a sink within the Combined Region to which the SECA applies. *Id.*

325. BGE notes that the SECA filings ignore power transactions that involved the Combined Region, but which were part of additional transactions that ultimately deliver the power outside of the Combined Region. *Id.* BGE emphasizes that this oversight is in direct opposition to the Commission's determination of what must be done at a minimum to render a SECA just and reasonable. *Id.* at 10, 35. Specifically, BGE criticizes the applicants for failing to comply with the express language of Paragraph 80 of the Commission's November 17 Order, which states: "We . . .order the parties to make adjustments to the NERC tag data submitted in the compliance filings . . . to remove 'hubbing transactions.'" *Id.* at 35.

326. BGE admits that hubbing transactions are not always easy to detect, requiring matching tag data to show where multi-link transactions started and ended. Nevertheless, the applicants' failure to even make the attempt constitutes a clear disregard for the Commission's requirements. *Id.* at 36.

327. Without the appropriate hubbing adjustments, the resulting SECA charge includes revenues associated with non-qualifying transactions that sunk outside the Combined Region. *Id.* at 10. BGE explains that the Commission's definition of SECA did not contemplate such transactions because these continue to be subject to T&O charges, leaving no lost revenue to be made up. *Id.* at 36. BGE believes that the imposition of SECA for these transactions would result in the unfair double recovery of revenue. *Id.*

328. BGE criticizes Mr. Heintz for his assumption that power with a POD outside of the Combined Region ultimately sank back to the Combined Region, and therefore should be included as lost revenues to be collected in the SECA. *Id.* at 37. BGE disapproves of the proposition that revenues belong in the SECA unless someone can prove otherwise, stating that this would turn the burden of proof on its head so that the ratepayer is essentially forced to prove the negative. *Id.*

329. BGE also challenges the approach taken by AEP witness, Mr. Bethel. BGE IB at 37. BGE criticizes Mr. Bethel for taking OATi tag data showing that power was transmitted out of the Combined Region in 2002 and then using matching OATi tag data to hub the power back into the Combined Region as a means of increasing the SECA. *Id.* According to BGE, this reverse hubbing increased SECA revenues to PJM by $12.7 million. BGE contends that Mr. Bethel than loses interest in the exercise of matching tags and does not find hubbed-out transactions. *Id.* Further, BGE faults Mr. Bethel for not submitting work papers that would allow others to determine the correctness of his work. *Id.*

330. Mr. Bethel identifies approximately 2.2 million MWh of power transmitted by AEP-West/CSWS to AEP-East and 2.6 million MWh going in the exact opposite direction. *Id.* at 38. BGE contends that Mr. Bethel is inconsistent in his treatment of these two transmissions because he reduces lost revenues by $4.26 million for the 2.6 MWh moving east to west but makes no comparable reduction for the 2.2 million MWh moving west to east. *Id.* BGE asserts that Mr. Bethel ignores that AEP's open-access tariff allows a customer to pay one rate for service to both AEP zones. *Id.* Using the same pricing in AEP-East and AEP-West, BGE argues that the SECA in PJM should be reduced by an additional $3.6 million. *Id.*

331. BGE accuses AEP and Exelon of inventing "In-Out-In" and "Out-In" transactions in order to inflate their lost revenue claims. BGE RB at 4. BGE remarks that the Commission does not allow multiple tying arrangements in order to declare a sink that increases the SECA. BGE takes the position that once a transaction leaves the Combined Region, it should be exempt from a SECA regardless of where the power subsequently sinks. *Id.*

332. BGE urges the Commission to ban all hubbing-in inferences drawn by the SECA applicants given that the hubbing-out transactions are being missed due to the incomplete information contained in the OATi tags. BGE IB at 39.

333. BGE emphasizes that because hubbing adjustments are an integral feature of a properly constructed SECA, their absence from the applicants' filings is "fatal" to the applicants' case. *Id.* If the filings are accepted notwithstanding this fatal flaw, BGE requests that the most extreme assumptions as to hubbing be imputed to the filings. *Id.* at 10. For instance, BGE requests that the Commission take the maximum conceivable

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

amount of hubbing as its starting point by imputing that anything that was exported out of PJM by entities that imported power into PJM was hubbed, and should be excluded from the lost revenue calculations. *Id.* at 39.

334. BGE refutes AEP/Exelon's contention that "In-Out" revenue is a legitimate component of the lost revenues claims of AEP, ComEd, PECO, Dayton and Dominion and should be recovered in this proceeding. BGE reemphasizes the Commission's express ruling that these types of transactions be excluded from lost revenue claims as a mandatory hubbing adjustment. BGE RB at 4. BGE adds that AEP/Exelon cannot justify their non-compliance based solely on their disagreement with the Commission's directive, as this type of collateral attack on the underlying Commission Orders falls outside of the scope of the instant compliance proceeding. *Id.* at 17.

Midwest ISO Transmission Owners

335. The Midwest ISO TOs did not themselves propose any hubbing adjustments in the development of lost revenues or SECAs. Midwest ISO IB at 67. Nevertheless the Midwest ISO TOs do support DENA's proposed hubbing adjustment, as articulated in Dr. Henderson's analysis. *Id.* The Midwest ISO Transmission Owners also indicate their willingness to include other hubbing adjustments in the development of lost revenues or SECAs, provided that such adjustments are approved by the Commission. *Id.*

336. The Midwest ISO TOs oppose BGE's position that the failure to include hubbing adjustments in the original analysis should negate the entire analysis. Midwest ISO RB at 48. The Midwest ISO TOs remark that although BGE had every opportunity to analyze the data and submit hubbing adjustments, it elected not to do so. *Id.* Having agreed to support all hubbing adjustments that are approved by the Commission, the Midwest ISO TOs fault BGE for failing to make whatever hubbing adjustment proposals it believed were necessary. *Id.*

337. Despite BGE's argument to the contrary, the Midwest ISO TOs deny that double recovery would automatically occur if the SECA obligations reflect the costs of moving power into regions where RTORs have not been eliminated. *Id.* The Midwest ISO TOs explain that under a scenario where a transaction from a source in the Midwest ISO moves through PJM and sinks in New York, the RTORs for the transaction would continue to be collected during the transition period because such RTORs were not eliminated. However, this type of transaction would not be included in the calculation of SECA obligations during the test period because it did not sink in the Combined Region. Because there are no "lost revenues" associated with such a transaction, there would be no double recovery. *Id.* at 48-49.

338. The Midwest ISO TOs aver that BGE is incorrect in its calculation of the average rates used in allocating the lost revenues of the Midwest ISO TOs. *Id.* at 49.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Specifically, the Midwest ISO TOs fault BGE's witness, Mr. Bourquin, for multiplying the average rate by only the MWhs associated with out and through transactions that sank in the Combined Region and inappropriately removing all revenues and MWhs sinking outside of the region. *Id.* According to Mr. Heintz, this methodology improperly restricts the collection of lost revenues associated with the elimination of RTORs, as such revenue recovery was never intended to be confined to transactions sinking in the Combined region. *Id.*

Discussion/Findings/Conclusions

339. Hubbing transactions are those in which power is transmitted through or out of either PJM or Midwest ISO to the other RTO, but the ultimate delivery is outside of the importing RTO. November 17 Order at P 77. AEP correctly notes that the settlements in this proceeding have mooted many of the hubbing transaction issues. Nevertheless, the important question to be addressed here is whether the compliance filings are adequate given the applicants' failure to include adjustments for hubbing transactions. For the reasons discussed below, the response is negative.

340. The Commission recognized that the OATi tag data showed certain transactions sinking in a particular control area even though the underlying transactions actually served load in another control area. In response to this, the Commission drafted Paragraph 80 of the November 17 Order, which required the parties "to make adjustments to the NERC tag data submitted in the compliance filings ordered herein to remove such 'hubbing' transactions." November 17 Order at P 80.

341. The Commission's order is clear in its requirement that the SECA applicants were the responsible parties for making the hubbing adjustments. The applicants' blatant non-compliance with the Commission's directive necessitates the rejection of their filings. Notwithstanding the Midwest TOs' "willingness" to accept hubbing adjustments made by other parties, such a passive approach does not constitute sufficient compliance with the express language of the order. See Ex. MTO-1 at 27:17-21; MTO-103 at 23:1-13, 2; See also Ex. MTO-99 at 4:3-6.

342. BGE correctly points out the fatal flaw in the testimony of Mr. Heintz, who essentially conceded his non-compliance with the Commission's order. In response to questioning about hubbing adjustments, Mr. Heintz candidly stated "I have none" while nevertheless acknowledging that such adjustments "need to be shown." Tr. 905 at 17-23. It is simply inadequate for Mr. Heintz to passively state that, "Once those hubbing adjustments have been proven, I will incorporate the hubbing adjustments." Exhibit. No. MTO-94 at 22:2-3.

343. By failing to include the required hubbing adjustments, the applicants' proposed SECA charges are unjust and unreasonable because they ultimately provide the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

applicants with double compensation. Transactions that sink outside of the Combined Region continue to be subject to T&O charges, and thus, there is no "lost revenue" for the applicants to recoup via the SECA. Imposing a SECA for these transactions would thus constitute a double recovery, making the charges unjust and unreasonable. Accordingly, all transactions sinking outside of the Combined Region must be removed from the SECA calculations. Because the applicants took no proactive steps in the removal of these transactions from their SECA calculations, the compliance filing is defective and must therefore be rejected. Mr. Bethel's approach, tantamount to a reverse hubbed in, must also be rejected. These uncorroborated adjustments result in over-recovery and are unjust and unreasonable and contrary to the Commission's intention in imposing the SECA.

344. Evidence of the fact that the Midwest ISO TOs failed to comply is found in Mr. Heintz' testimony: Mr. Heintz asserts that hubbing adjustments require a thorough analysis to determine the amount of imports ultimately exported out of PJM. Ex. MTO-99 at 9:21-23. Mr. Heintz admitted that he did not conduct such a review. Ex. MTO-9 at 9:23 - 10:1.

345. The proposed hubbing adjustment for generation-only control areas, as implemented by Dr. Henderson on behalf of Duke Energy North America (DENA) and Allegheny Energy (Allegheny) are correct and in compliance with the Commission's orders.

Issue 4: Shift to Shipper: A. Have entities seeking to shift SECA obligations to shippers provided sufficient showings pursuant to Paragraph 45 of the November 17, 2003 Order in Docket No. ER02-111?

Background

346. The Commission recognized that in certain instances, the benefits of the RTOR elimination would not accrue to the LSE, but rather to the LSE's supplier who had traditionally paid the charges for T&O service pursuant to the relevant contract for delivered power. November 17 Order, 105 FERC ¶ 61,212 at P 45. In addition to paying SECA, LSEs with bundled delivery contracts extending into the transition period would also be paying RTORs, which remained embedded in the long-term contract price even after the Commission's elimination of these rates. *Id.* at 45 n.94. To prevent this unjust and unreasonable "double payment," the Commission provided a mechanism whereby a LSE could shift its SECA liability to its supplier. *Id.* The Commission articulated this mechanism in Paragraph 45 of the November 17 Order, which states as follows:

> "[A]s part of the compliance filing process, we will allow LSEs under existing contracts for delivered power that continue into the transition period to demonstrate that the supplier is the shipper for such transactions

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

> and to propose that the supplier be required to pay the SECA for that portion of the LSE's load served by the contract."

November 17 Order, 105 FERC ¶ 61,212 at P 45.

347. A number of parties have filed shift-to-shipper claims pursuant to Paragraph 45. Many of these claims have already been settled. The claims of the remaining parties are set forth and discussed below. The first portion of this section examines the shift-to-shipper dispute involving Michigan South Central Power Agency (MSCPA), The Six Michigan Cities, Constellation Energy Commodities Group, Inc. (CCG), CMS Energy Resource Management (CMS ERM), and AEP. The second portion of this section examines the shift-to-shipper disputes involving Mirant Americas Energy Marketing (Mirant), Quest Energy, LLC (Quest), and WPS Energy Services Inc. (WPS ESI). Each grouping of claims will include a summary of the parties' contentions, followed by a discussion that sets forth specific findings based on an interpretation of Paragraph 45 that captures the intent of the Commission, while preserving a general sense of fairness.

Parties' Contentions – Group One

Michigan South Central Power Agency

348. MSCPA contends that it has made a sufficient showing and has met all the criteria pursuant to Paragraph 45 to shift a portion of its SECA liability to its long-term power supplier, CCG. MSCPA IB at 12.

349. MSCPA asserts that, as required under the Commission's order, its agreement with CCG is an existing contract for delivered power that continues beyond December 1, 2004, into the transition period. *Id.* at 12. Specifically, MSCPA explains that it had entered into a Power Purchase and Sale Agreement with CMS ERM, running from January 1, 2002 through December 31, 2008. *Id.* By letter dated February 14, 2003, CMS ERM subsequently assigned its obligation under the contract to its successor, CCG. *Id.* MSCPA explains that pursuant to the assignment agreement, before the transition period began, CCG expressly agreed to assume all of CMS ERM's rights, duties and obligations under the Transaction and the Master Agreement on the effective date. MSCPA IB at 13.

350. MSCPA argues (and CCG's own witness concedes) that CCG is the only relevant supplier for purposes of power delivered pursuant to the agreement. MSCPA IB at 14. MSCPA adds that this is true regardless of whether CCG uses other suppliers from whom it purchases the power it sells to MSCPA. *Id.* MSCPA's witness, Mr. White further explains that MSCPA's "chain of supply" includes no other party except CCG; any further upstream suppliers exist in CCG's "chain of supply," not that of MSCPA. *Id.* at 10, *quoting* Ex. MSC-9 at 4:17-20. MSCPA maintains that it is under no obligation to

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

seek out CCG's upstream shippers to successfully assert a shift-to-shipper claim. *Id.* at 18.

351. MSCPA contends that CCG is not only the supplier under the agreement, but it is also the shipper. *Id.* at 14. Dismissive of CCG's contention that the term "shipper" is infrequently used in the electric power industry, MSCPA points out that energy is not supplied until it is delivered or transmitted from the point of origin to the point of delivery specified in the agreement. *Id.* at 15. Thus, CCG cannot supply power to MSCPA until it ships that power to the specified delivery point. *Id.* MSCPA emphasizes that it is immaterial whether or not CCG makes the transmission arrangement because it receives the contract price as though it does. *Id.* MSCPA also points out that the agreement's express requirement that CCG "deliver" the power to MSCPA at the delivery point further demonstrates that CCG acted as the shipper. MSCPA RB at 14. MSCPA maintains that the Commission's order does not articulate any requirement that a shipper must also hold the transmission reservation. *Id.* at 15.

352. MSCPA also argues that shifting its SECA costs to CCG makes sense from a cost-causation perspective. MSCPA IB at 17. Specifically, MSCPA points out that it has received no benefit from the elimination of RTORs and is, in fact, worse off today because it is locked into its contract with CCG and must therefore pay both the contract price and the SECA. *Id.* at 18. MSCPA maintains that CCG has benefited, comparatively. *Id.* at 17-18. For instance, CCG has the discretion to determine how it will meet its transmission obligations under the contract. *Id.* Furthermore, CCG is not required to flow through any savings resulting from the elimination of the RTOR back to MSCPA. *Id.* Finally, CCG has the option under the agreement to outsource the power from wherever it wants in the combined region without paying a RTOR. In contrast, MSCPA has no such option. *Id.* at 18.

353. MSCPA contends that CCG's emphasis on identifying the precise beneficiary of the Commission's elimination of RTORs is misplaced. MSCPA RB at 5. MSCPA notes that the November 17 Order does not require that a party seeking to shift SECA to its supplier demonstrate that its supplier actually benefited from the elimination of RTORs. *Id.*

354. MSCPA derives the amount of $884,355 to be shifted to CCG based on the amount of energy purchased from CCG under the agreement. *Id.* at 19. MSCPA acknowledges that it conducted some third-party transactions for delivered power that were unrelated to its contract with CCG. *Id.* Using the average T&O rate for each of the four rate periods, MSCPA estimates that the SECA obligation associated with these transactions amounts to $111,163 (out of its total $995,518 SECA obligation). *Id.* MSCPA is not seeking to shift the SECA associated with these transactions to CCG. *Id.* MSCPA defends its use of test period data to calculate the amount of SECA charges that should be shifted to CCG by pointing out that the Commission based its SECA calculations on test period

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

data applied to the transition period. MSCPA RB at 20. Accordingly, MSCPA implements the same methodology for calculating the amount of SECA to be shifted in the instant proceeding. *Id.*

355. MSCPA argues that CCG's calculations are fundamentally flawed and incomplete. *Id.* at 23. MSCPA contends that CCG ignored 12 of the 16 months of the transition period by excluding liability as of April 1, 2005, the date the Midwest ISO Day 2 markets began. *Id.* Additionally, MSCPA faults CCG for ignoring test period transactions undertaken by CMS ERM. *Id.*

356. MSCPA addresses CCG's additional claim that it was not the supplier during the test period and that any shift-to-shipper claim arising from this period should be paid by CMS ERM. *Id.* at 20. MSCPA responds that the burden of shifting the SECA to CMS ERM (or any of CCG's upstream suppliers) lies with CCG, not MSCPA. *Id.* MSCPA also notes that CCG elected to purchase the Agreement from CMS ERM, and CCG elected to deal with whatever upstream suppliers it believes are involved. *Id.* Accordingly, MSCPA maintains that its contract remains with CCG, and only CCG. *Id.*

357. MSCPA responds to CCG's argument that the term "transaction" should be read broadly and that the Michigan LSEs improperly conflate the terms "contract" and "transaction" in Paragraph 45 of the November 17 Order. *Id.* at 16. MSCPA contends that the plain meaning of the order does not support this argument because the subject of the sentence at issue ("existing contracts for delivered power") precedes the words "such transactions." *Id.* Merriam Webster defines "such" as an adjective meaning "of the character, quality or extent previously indicated or implied," or "of the same class, type or sort." *Id.* Based on this definition, MSCPA contends that the word "such" in the context of Paragraph 45 must describe the previously-referenced word "contracts." *Id.*

358. MSCPA opposes CCG's attempt to dodge SECA liability based on the claim that MSCPA conducted resales to third parties in 2005 and thus did not use all of its delivered power to serve load. *Id.* at 24. MSCPA maintains that these third-party sales were not "resales," as CCG contends. *Id.* Rather, the sales originated from generating units owned and operated by MSCPA. *Id.*

359. If CCG prevails in its argument that it should not be liable for SECA charges associated with transactions resulting from the implementation of Midwest ISO's Day 2 markets, MSCPA similarly seeks to be discharged from SECA liability associated with these market transactions. *Id.* at 25-26.

360. MSCPA reemphasizes its belief that CCG is primarily liable for the SECA charges associated with the Agreement. *Id.* at 28. Nevertheless, MSCPA also points out that CMS ERM could potentially be liable under a shift-to-shipper claim in the event that the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Commission accepts CCG's argument that CMS ERM served as the supplier during the test period. *Id.*

Six Michigan Cities

361. The Six Michigan Cities, comprising Michigan Public Power Rate Payers Association (comprising the Village of Chelsea, City of Eaton Rapids, City of Hart, City of St. Louis, and the City of Portland) (MPPRPA) and Bay City, Michigan (Bay City), contend that for all power supply contracts to the Six Michigan Cities, the supplier is the contractual shipper who, under Paragraph 45, should bear all SECA charges assessed to the Cities. Six Michigan Cities IB at 6. Specifically, the Six Michigan Cities are seeking to shift their entire SECA obligations to CCG, in the amounts of $742,459 (for MPPRA) and $655,236 (for Bay City). *Id.* at 4.

362. The Six Michigan Cities base their shift claims on the explicit language of the contracts between them and CCG, which provide that CCG is liable "for all costs, liabilities and charges of any kind relating to, or arising from, the supply and delivery of capacity and energy to any Consumers Energy interface."[86] Six Michigan Cities IB at 5. The Six Michigan Cities argue that SECA charges are undisputedly of the type referenced in this clause. *Id.*

363. Under the terms of the contract, CCG is responsible for delivering power to the Six Michigan Cities at a fixed price. *Id.* at 8. This gave CCG the economic risk and benefit of any changes to the cost of generation and/or transmission. Because these contracts were negotiated before the de-pancaking of rates, they encompass the fundamental assumption that the price includes whatever pancaked transmission charges the power was expected to encounter en route to the delivery point. Accordingly, the Six Michigan Cities were financially disadvantaged by the contract after the de-pancaking of rates because the price of the negotiated power contracts remained unchanged. *Id.* at 8-9. In contrast, CCG stood in a position to benefit. *Id.* at 9. For instance, CCG could have opted to perform its contractual obligation to the Six Michigan Cities by itself entering into long-term contracts with upstream suppliers and then filing "ripple" claims. *Id.*

364. Alternatively, CCG had the option to select power supply sources that would have to be shipped across remote paths. *Id.* It also had the right to select either bundled or unbundled power supply sources. *Id.* Notwithstanding these savings accruing from the elimination of RTORs, CCG continued to receive from the Six Michigan Cities a delivered-power price that was inflated by the outdated assumption of pancaked rates. *Id.* Additionally, CCG possessed the discretionary authority to determine the source of the power, and it was also the party with the financial responsibility for the transmission

[86] Ex. MTDU-54 at §12 (MPPRPA member sample contract); Ex. MTDU-58 at §12 (Bay City contract).

costs. *Id.* at 17. The Six Michigan Cities assert that their contracts with CCG were for power delivered at or within the zone of the LSE, as required for a successful shift-to-shipper claim under Paragraph 45. *Id.* at 10. Indeed the specific language of the contract provides that CCG "assumes the responsibility for delivering energy to the Delivery Points." The Six Michigan Cities point out that CCG's own witness agrees that the "Delivery Point" refers to the city gates of the Six Michigan Cities. *Id.*
365. The Six Michigan Cities state that their contracts clearly indicate an effective date of January 1, 2002, the start of the test period. *Id.* at 10. The MPPRPA agreement continues until the end of 2011, and the Bay City agreement continues until the end of 2006. *Id.* Accordingly, the Six Michigan Cities argue that these contracts were undisputedly in existence and effect throughout the entire test period and transition period. *Id.* at 10-11.

366. The Six Michigan Cities contend that the contracts at issue are clearly requirements contracts, whereby CCG was obligated to serve all of the Six Michigan Cities' loads. *Id.* at 11.

367. Bay City maintains that its contractual counterparty is the relevant supplier in these proceedings and is also the party to whom SECA liability should be shifted pursuant to Paragraph 45. *Id.*

368. Bay City understands that although CMS ERM sought to assign the Bay City Contract to CCG, there is an apparent dispute as to whether the assignment was actually accomplished. *Id.* at 11-12. Bay City consented to the proposed assignment at a special meeting on November 17, 2003. *Id.* at 12. But with regard to the dispute, Bay City refrains from taking a position and instead maintains that its shipper under the contract is either CMS ERM or CCG. *Id.* Bay City expects to shift $655,236 in SECA charges from whichever of these two entities is deemed to be the shipper. *Id.*

369. In response to CMS ERM's contention that the shifting of SECA charges from Bay City to CMS ERM would constitute retroactive ratemaking, Bay City notes that such an argument is applicable only if CMS ERM did not provide service during the transition period. *Id.* at 4. However, if the Commission determines that CMS ERM retained performance responsibility for the contract, CMS ERM would effectively be providing service during the transition period pursuant to the Bay City contract, thereby undermining the argument of retroactive ratemaking. *Id.*

370. The Six Michigan Cities fundamentally disagree with CCG over the correct interpretation of a particular sentence within Paragraph 45 of the Commission's order, hereafter referenced as the "P 45 Shift Sentence": "[W]e will allow LSEs under existing contracts for delivered power that continue into the transition period to demonstrate that the supplier is the shipper for such transactions and to propose that the supplier be required to pay the SECA for that portion the LSE's load served by the contract." *Id.* at

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

6-7 (quoting November 17 Order, 105 FERC ¶ 61,212 at P 45). Specifically, the Six Michigan Cities criticize CCG for artificially limiting its SECA responsibility by interpreting the phrase "shipper for such transactions" of the P 45 Shift Sentence as the equivalent of "transmission customer." *Id.* at 13. Under such an interpretation, CCG concedes to being the shipper (and accepting liability under Paragraph 45) in situations where it procures power from a generator located inside PJM and subsequently enters into a separate transmission agreement to get that power to MISO. *Id.* But for other procurement transactions, such as entering a bundled arrangement whereby an upstream supplier delivered the power to CCG at the PJM-MISO border, CCG maintains that it was not the shipper under Paragraph 45. *Id.* In contrast, the Six Michigan Cities argue that the Commission purposefully used the term "shipper for such transactions" rather than "transmission customer" because it did not intend the two to be synonymous. *Id.* at 14.

371. The Six Michigan Cities also point out that the P 45 Shift Sentence specifically references "the supplier" in the singular, even though that clause follows a series of plurals. *Id.* at 15. According to the Six Michigan Cities, this sentence construction indicates that there can be only one shipper per contract to deliver power to the LSEs. *Id.* Although there may be multiple upstream transmission customers, there are only two parties to the LSE-Supplier contract. *Id.*

372. Contrary to the testimony by CCG witness, Mr. Meyer, the Six Michigan Cities also argue that the phrase "such transactions" in the P 45 Shift Sentence must refer back to the phrase "contracts for delivered power that continue into the transition period." *Id.* at 14. The Six Michigan Cities aver that in both instances, the Commission is referring to the particular contract that the LSE is under (and, accordingly, to which the LSE is a party). *Id.* The Six Michigan Cities emphasize that this interpretation is consistent with common English usage because the word "such" as a modifier signals an intent to refer back to a concept mentioned in close, prior proximity. *Id.* at 15. Accordingly, the Six Michigan Cities contend that the phrase "shipper for such transactions" directs the reader to consider the "contract for delivered power" between the LSE and its supplier for purposes of determining the shipper to incur SECA liability. *Id.*

373. The Six Michigan Cities conclude that, based on the letter and the purpose of the Commission's Order, it was CCG, not the Six Michigan Cities that stood to benefit from the elimination of RTORs – whether or not CCG was the "transmission customer" that directly paid the RTORs when they were in effect. *Id.* at 19.

374. The Six Michigan Cities criticize as economically unsound the testimony of CCG's expert (who, the Six Michigan Cities emphasize, is not an economist). *Id.* at 20. The testimony at issue asserts that the benefits of the elimination of pancaked charges are realized only by the entity in the stream of commerce that avoids paying the actual PJM-area RTOR charge as the transmission customer. *Id.* The Six Michigan Cities contrast

this testimony with that of Dr. Henderson, an actual economist. Dr. Henderson explains that each entity along the stream of commerce benefits to some extent from the elimination of RTORs by paying a total price that excludes the cost of PJM-area transmission. *Id.* However, he explains the principal beneficiary is the particular entity in the stream that gets to buy low and sell high; he then labels CCG as the "lucky winner." *Id.* at 20-21.

375. The Six Michigan Cities argue that the structure of Paragraph 45 suggests that it is more appropriate for a LSE to bring a shipper claim against its contractual counter-party, rather than to a supplier that lies further up the chain. *Id.* at 21. The Six Michigan Cities recognize that while CCG's upstream purchases from AEP may be the subject of a "ripple" claim, these transactions should not be the subject of a "shift" claim. *Id.* The Six Michigan Cities also emphasize the importance of contractual privity. *Id.* Notably, the Six Michigan Cities do not have a contract (nor have they engaged in any transactions) with AEP or Exelon or any other possible supplier to CCG. *Id.*

376. To demonstrate the Commission's intent that a shift-to-shipper claim be brought within the paradigm of a contract, the Six Michigan Cities reference the following three key phrases in the P 45 Shift Sentence: "LSEs under existing contracts," "such transactions," and "portion of the LSE's load served by the contract." *Id.* at 21-22. According to the Six Michigan Cities, the Commission did not mean one contract the first time it used the word and an entirely different contract the second time it used the word contract, while sandwiching a reference to some transaction not fully described by either contract. The Commission meant the LSEs should turn to the entity that supplies them. And if the supplier can identify another supplier, the Commission intended further so called "ripple claims." *Id.* at 22.

377. The Six Michigan Cities disagree with CCG as to the appropriateness of relying on reference OATi tags to determine shift-to-shipper SECA liability, citing both legal and practical difficulties with such an approach. *Id.* at 23-24. As a legal matter, the Commission did not reference OATi tags in the P 45 Shift Sentence; it referenced contracts. *Id.* at 23. From a practical standpoint, the Six Michigan Cities note that the tags are subject to error and are difficult to interpret. *Id.* at 24. On cross examination, even CCG's own expert could not explain the information on the tags he sponsored. *Id.*

378. Reemphasizing that they have not benefited financially from the elimination of RTORs, the Six Michigan Cities proceed to attack the "benefits test" set forth by CCG's expert Mr. Meyers. *Id.* at 26. Specifically, the Six Michigan Cities criticize Mr. Meyer's proposition that if CCG did not benefit, then its customer must have benefited, and that the SECA therefore should not shift. *Id.* In response, the Six Michigan Cities argue that for situations where neither the LSE nor the supplier benefit, the only hope of matching SECA with the ultimate upstream supplier who did benefit is to first allow the LSE to shift its SECA to its supplier and then allow any subsequent ripple effects. *Id.* The Six

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Michigan Cities aver that assigning SECA in this way is more "consistent with the principle of cost causation during the transition period," as prescribed by the Commission's Order. *Id.* at 27 (quoting November 17 Order, 105 FERC ¶ 61,212 at P 48).

379. The Six Michigan Cities argue in the alternative that, at the very least, CCG's partial concession of SECA liability based on a four-month analysis should be extrapolated to cover all sixteen transition months, making the total amount of liability "considerably larger" than the $78,000 to which CCG specifically concedes. *Id.* at 27. According to the Six Michigan Cities, CCG derives this figure based on the first four months of the transition period. The Six Michigan Cities claim that a comparable analysis should have been performed to measure liability for the following twelve transition period months. *Id.* at 28. The Six Michigan Cities propose to extrapolate CCG's admission of $78,000 in liability to yield a new liability of $546,000[87] which appropriately accounts for the larger and longer charges associated with the following twelve transition period months. *Id.*

380. The Six Michigan Cities also criticize CCG's argument that it should be exempt from paying SECA for the subsequent 12 months of the transition period because its business practices during this time were driven by the implementation of the Midwest ISO's Day 2 market, rather than the Commission's elimination of RTORs. *Id.* at 28-29. First, the Six Michigan Cities point out that CCG failed to actually review the OATi tag data from these twelve months to see whether it contained tags resembling the tags underlying the $78,000 figure. *Id.* at 29. Rather, CCG presumed that the OATi tags were comparable without providing any information to support such an assumption. *Id.* Second, the Six Michigan Cities also dismiss CCG's contention that different facts were lurking within the April – March data, deeming this to be an untimely "known and measurable change" argument. Six Michigan Cities IB at 29. The Six Michigan Cities note that this line of argument should have been addressed in Phase I testimony. The Six Michigan Cities contend that they should not have to pay the price of CCG's failure to raise arguments that would have reduced the SECA charges billed to the Six Michigan Cities. *Id.* at 29-30. Finally, the Six Michigan Cities argue that CCG continued to tag substantial MWh out of PJM and into MECS throughout the transition period, even after the start up of the Day 2 markets. *Id.* at 30.

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[87] This calculation is based on dividing the $78,000 admission by four to determine the monthly amount. That result is doubled to estimate the per month liability associated with the 2003 test period. The 2003 test period monthly estimate is multiplied by 12 for the estimate of the total transition period liability associated with the 2003 test period. The total 2003 test period liability is then added to CCG's admitted liability for the 2002 test period. In equation form: (78,000/4) x 2 x 12 +78,000 = $546,000. Six Michigan Cities IB at 28 n. 97.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

381. The Six Michigan Cities refute CCG's argument that they have conflated the supplier and shipper elements of Paragraph 45, depriving the two terms of independent meaning. Six Michigan Cities RB at 15. Arguing that CCG has misconstrued filed testimony on this point, the Six Michigan Cities agree that a "contract for delivered power" necessarily includes both a power-supplier sub-requirement and a power-shipper sub-requirement. *Id.* In fact, the Six Michigan Cities insist that their own witness, Mr. Solomon, presented an example in which the supplier was not the shipper.[88] Based on evidence of CCG's physical delivery obligation and financial delivery obligation, the distinct power-shipper sub-requirement has been met. *Id.* at 15.

382. The Six Michigan Cities maintain that the Commission's November 17 Order did not include a benefits test as part of the requirements for a successful shift-to-shipper claim. *Id.* at 24-25. Moreover, the Six Michigan Cities insist that the word "propose" in Paragraph 45 does not give rise to such a test; rather this language merely provides for the possibility that some contracts might include terms making a shift of SECA charges inappropriate. *Id.* at 25.

Constellation Energy Commodities Group, Inc.

383. CCG refutes the shift-to-shipper claims brought by MSCPA, Bay City, and MPPRPA (collectively, the Michigan LSEs).[89] Specifically, CCG contends that the Michigan LSEs failed to demonstrate that CCG was the "shipper" that benefited from the elimination of RTORs within the meaning of Paragraph 45 of the November 17 Order. CCG IB at 16.

384. Remarking that the principles of cost causation operate in tandem with the benefits test, CCG argues that any determination of SECA obligations must be proportionate to the benefits received. *Id.* at 21. According to CCG, all parties agree that the beneficiary of the November 17 Order is the shipper that obtained transmission service across a relevant seam between PJM and the Midwest ISO for deliveries to the Michigan LSEs without having to pay RTORs. *Id.* The dispute, however, is over the identity of the "shipper." *Id.*

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[88] *Id.* at 21-22. Mr. Solomon cites a power purchase contract in which Old Dominion Electric Cooperative (ODEC) bought power at the generator busbar. Six Michigan Cities RB at 21-22. In this instance, the supplier was the generator and the shipper was the LSE. *Id.*

[89] In its reply brief, CCG also argues that Green Mountain has waived and, therefore, lost its rights to pursue any shift-to-shipper claims against its upstream suppliers. CCG RB at 30.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

385. CCG disputes the meaning of the term "supplier" in the context of Paragraph 45. *Id.* at 26. CCG argues that the Michigan LSEs are incorrect in limiting the term's meaning to the counterparty of a power supply agreement. *Id.* Instead, CCG interprets the term "supplier" to mean any party in the chain of supply from the generator (*i.e.*, the source) to the LSE (*i.e.*, the sink). *Id.*

386. CCG also disapproves of the Michigan LSEs' blending of the terms "supplier" and "shipper." *Id.* at 35-36. These terms must have distinct meanings, urges CCG; otherwise the Commission's language in Paragraph 45 that a LSE "demonstrate that the supplier is the shipper" would be superfluous. *Id.* at 36. Because the Michigan LSEs have failed to give meaning to the Commission's order, CCG requests that the LSEs' position be rejected. *Id.* CCG insists that rather than assuming the supplier is the shipper merely because it is the contractual party, the only consistent interpretation of the Commission's words is for the LSE to identify the party in the chain of supply that holds or requests "through and out" transmission service and, therefore, benefited from the elimination of RTORs. *Id.* at 39.

387. CCG argues that even if all the specific requirements of Paragraph 45 are met, the LSE does not have a "guaranteed right" to shift its SECA obligations. *Id.* Referring to the language in the November 17 Order stating that a LSE may "propose that the supplier be required to pay the SECA," CCG contends that the word "propose" strikes down any claims of absolute entitlement by the LSE. *Id.* at 29. CCG maintains that a LSE must, at minimum, demonstrate that the benefits to the shipper resulted directly from the Commission's elimination of RTORs, and not some intervening event. *Id.* In the absence of such a demonstration, the shifting of SECA would be unjust and unreasonable. *Id.*

388. CCG emphasizes that the LSE bears the burden of proof in demonstrating that another party was the actual beneficiary of the Commission's elimination of RTORs. *Id.* at 30. According to CCG, the Michigan LSEs failed to meet this burden because, among other things, they adopted too restrictive an interpretation of the word "supplier," one that CCG believes is inconsistent with the November 17 Order. *Id.* at 31. CCG maintains that a counterparty to a delivered power contract is not necessarily the only supplier relevant for purposes of a shift-to-shipper claim. *Id.* at 31-32. CCG further explains that by considering other parties in the chain of supply – outside of the two contractual parties – one is more accurately able to discern the actual beneficiaries of the Commission's elimination of RTORs. *Id.* at 32-33.

389. According to CCG, the party benefiting from the elimination of RTORs may be an entity outside the immediate contract for power delivery, such as an upstream supplier or a generator. *Id.* at 32-33. Indeed, CCG points out that the Commission specifically makes reference to "generators" in Paragraph 45, suggesting that these ought to be

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

included in the definition of "supplier." *Id.* CCG explains that in its role as a power marketer, for a vast majority of transactions, it should not incur SECA liability because it served as neither the generator nor the transmission customer that benefited from the RTORs. *Id.* at 33.

390. Even if the term "supplier" were to be defined as narrowly as the Michigan LSE's contend, CCG denies that it could ever owe SECA charges to Bay City. *Id.* at 34. Specifically, CCG argues that it is not a counterparty or a direct supplier of Bay City. *Id.* at 34. Rather, CCG insists that it acted only as CMS Energy Resource Management Company's (CMS ERM) agent with respect to the Bay City contract, pursuant to a Servicing and Back-to-Back Agreement dated April 1, 2003. *Id.* at 34. Under this agency relationship, CCG's delivery of power to the LSE fulfills its obligations to CMS ERM under the Back-to-Back Agreement, and CCG's receipt of payment from the LSE fulfills CMS ERM's reciprocal obligation under the Back-to-Back Agreement. *Id.* Because Bay City never signed the assignment and release agreement, CCG maintains that it continues to act as CMS ERM's agent for purposes of the contract. *Id.* at 35.

391. Although the Six Michigan Cities' witness, Mr. Solomon, attempts to provide examples of situations where the supplier is not the shipper, CCG points out that Mr. Solomon conceded that neither of his proffered examples is relevant to this proceeding. *Id.* at 40.

392. CCG also claims that the use of the word "such" before "transactions" was intended to refer to transactions that are related to the delivered power contract and that continue into the transition period. *Id.* at 45. Thus, a delivered power contract is necessary, but not sufficient for a LSE to shift SECA charges pursuant to Paragraph 45. *Id.* CCG concludes that the last sentence of Paragraph 45 must be interpreted as providing the LSE an opportunity to demonstrate which party in the chain of supply (*i.e.*, supplier) was the transmission customer (*i.e.*, shipper) that actually benefited from the Commission's elimination of RTORs. *Id.* at 46. This is the appropriate party to pay the SECA charges. *Id.*

393. CCG asserts that the Michigan LSEs have not even attempted to demonstrate that CCG is the shipper that benefited from the Commission's elimination of RTORs. *Id.* at 46-47. CCG specifically criticizes the Michigan LSEs for taking the simplistic position that merely because the Michigan LSEs did not benefit from the elimination of RTORs, CCG is the only party that could have benefited. *Id.*

394. CCG contends that the Michigan LSEs are inconsistent in their interpretation of the Paragraph 45 because while they acknowledge that the Commission's intent was to determine the beneficiary of the elimination of RTORs, the Michigan LSEs nevertheless argue that the question of whether CCG was the shipper that actually benefited is one that is either unnecessary or irrelevant. *Id.* at 48.

395. CCG disagrees that the task of determining who benefited upstream, and by what amounts, is overly burdensome or requires a "Herculean effort," as the Six Michigan Cities contend. *Id.* at 49. CCG points out that the Six Michigan Cities have access to OATi tag data, which show, *inter alia*, the source of the power, the shipper of the power across a relevant seam, and the ultimate sink. *Id.* at 50. Thus the task of determining the upstream beneficiary, rather than being insurmountable, is merely part of conventional discovery practice. *Id.* at 51.

396. CCG also argues that MSCPA failed to properly demonstrate the amount of SECA charges it proposed to shift to CCG because it focused only on test period (2002-2003) data and made no adjustments to the amount of SECA charges to be shifted to CCG based on transition period data. *Id.* at 51-2. CCG points out that that this analysis is fundamentally flawed because, according to the plain language of the Commission's order, Paragraph 45 is applicable only to contracts that continue into the transition period. *Id.* at 52-3.

397. According to CCG, MSCPA neglected to account for resales to third parties and thus failed to demonstrate that the power it purchased from CCG was actually used to serve MSCPA's load. *Id.* at 52. Based on MSCPA's acknowledgment of having sold 57,345 MWh of power to third parties in 2005, CCG estimates that 21.8 percent of the power it sold to MSCPA was not needed to serve load. *Id.* at 54.

398. CCG explains that it generally meets its contractual obligations to the Michigan LSEs by buying 50 MW blocks of power from AEP which it then shapes to meet the requirements of the individual LSE. As a result, CCG contends that AEP was the shipper that benefited from the Commission's elimination of RTORs. *Id.* at 55-66. Mr. Meyer testified that the OATi tag data associated with transactions involving AEP clearly indicate that the power was sourced by AEP from within PJM and sank with the Michigan LSEs in the MECS region of the Midwest ISO. *Id.* at 55. CCG insists that for these transactions, AEP was both the generator and the relevant transmission customer. *Id.* at 56. Accordingly, CCG concludes that AEP was the party in the chain of supply to the Michigan LSEs that was the shipper that benefited from the Commission's elimination of RTORs. *Id.*

399. Based on the same methodology used by the TOs to calculate the SECA charges in their compliance filings, CCG calculated the amount of SECA charges for which AEP should be liable at $809,635. *Id.* at 18, 56-57. CCG concedes liability for $313,123 in SECA charges, as these charges were associated with transactions that were not serviced by AEP. *Id.* at 18.

400. Although AEP argues that its SECA liability should be based on the actual savings in transmission costs experienced in the transition period, CCG points out that this

contention is contrary to the plain language of the Commission's order, which refers specifically to the SECA charge and makes no mention of the amount actually saved by the supplier. *Id.* at 57.

401. Alternatively, CCG states that it was not the "shipper" that benefited from the elimination of RTORs for its purchases from the Midwest ISO's Day 2 markets. *Id.* at 62. CCG explains that it used the Midwest ISO Day 2 markets to purchase any remaining power that was necessary to meet its obligations to the Michigan LSEs. *Id.* CCG points out that it cannot be considered a "shipper" in this instance because these transactions were completely internal to the Midwest ISO. *Id.* Since the transmission of power did not cross a relevant seam between PJM and MISO, there was no T&O transmission service associated with CCG's purchase, and accordingly, CCG could not have benefited from the Commission's elimination of RTORs. *Id.* at 62-63.

402. CCG criticizes the Six Michigan Cities for unveiling a new set of calculations and assumptions that purportedly shift $546,000 of SECA responsibility to CCG. *Id.* at 18. CCG contends that because these calculations were not part of the record and were not subjected to cross-examination, they are untimely and should be disregarded. *Id.* at 17-18. In the alternative, CCG avers that even if such claims are considered, they must be rejected on the merits. *Id.* at 19. Specifically, CCG contends that it should not be responsible for any SECA charges after April 1, 2005 because, subsequent to this date, CCG did not engage in cross-border transmission but instead relied on the Midwest ISO's Day 2 markets. *Id.* at 20. Accordingly, CCG emphasizes that it was not the shipper for these transactions. *Id.* at 21.

403. CCG challenges AEP's assertion that CCG failed to present a *prima facie* case that would shift SECA to AEP. *Id.* at 25. CCG contends that it assumes this burden of proof only after the Michigan LSEs initiating the shift-to-shipper claims have first met their own burdens in establishing a *prima facie* case. *Id.* Although CCG stands by its position that the Michigan LSEs have not met this burden, CCG maintains that it has put forth sufficient evidence to show that AEP is the actual beneficiary of the Commission's elimination of RTORs for the long-term confirmations between CCG and AEP. *Id.* at 5, 25. Specifically, CCG notes that it has satisfied the four requirements of a shift-to-shipper claim as identified by AEP's own witness. *Id.* at 25-28. CCG also maintains that, contrary to AEP's assertions, the OATi tag data analyzed by Mr. Meyer demonstrate that the power delivered pursuant to the CCG/AEP contract did in fact sink with the Michigan LSEs. *Id.* at 28-29.

CMS Energy Resource Management Company

404. Pursuant to a purchase and sale agreement that became effective on February 12, 2003, CMS ERM sold its "wholesale electricity to load-serving entity" business to CCG. CMS ERM IB at 4-5. As part of that sale, CMS ERM sold its power supply agreements

with MSCPA and Bay City to CCG. *Id.* CMS ERM claims that MSCPA and Bay City consented to the assignment of their power supply agreements from CMS ERM to CCG on February 14, 2003, and November 21, 2003, respectively. *Id.* CMS ERM emphasizes that at no point during the transition period did it supply MSCPA or Bay City with power. *Id.* at 8. Moreover, CMS ERM denies being the "shipper" with respect to such transactions. *Id.* Accordingly, CMS ERM contends that there is no basis for MSCPA or Bay City to shift their SECA obligations to CMS ERM. *Id.*

405. Citing MSCPA's failure to introduce any evidence or testimony suggesting that CMS ERM supplied it with power during the transition period or shipped power to supply it during the Transmission Period, CMS ERM contends that MSCPA has no basis under Paragraph 45 of the November 17 Order to shift SECA to CMS ERM. *Id.* at 8.

406. CMS ERM states that, under the terms of the assignment and release agreement dated February 14, 2003, MSCPA consented to the transfer of its power supply agreement with CMS ERM to CCG. *Id.* at 9. Moreover, CMS ERM interprets the terms of this agreement as prohibiting MSCPA from seeking any claim for payment for any liability, such as SECA liability, which arises after the effective date, which was April 2, 2003. *Id.* CMS ERM maintains that at no time during the transition period did it supply MSCPA with power, transport power to be supplied to MSCPA, or have a contract to supply MSCPA with power. *Id.* at 9-10.

407. Citing Bay City's failure to introduce any evidence or testimony suggesting that CMS ERM supplied it with power during the transition period or shipped power to supply it during the transmission period, CMS ERM contends that Bay City has no basis under Paragraph 45 of the November 17 Order to shift SECA to CMS ERM. *Id.* at 10.

408. CMS ERM refutes Bay City's position that, notwithstanding its consent to the assignment of the power supply agreement from CMS ERM to CCG, it must include CMS ERM as a possible party to whom SECA should be shifted. *Id.* at 10. CMS ERM believes that this contention was made based on CCG's representations that CMS ERM was the contractual counterparty supplying power to Bay City. *Id.* at 10. However, CMS ERM maintains that CCG's opinions and representations are not only incorrect but also irrelevant because the record clearly establishes that CCG – not CMS ERM – served as Bay City's power supplier during the transition period. *Id.* CMS ERM emphasizes that its inclusion as a possible party to incur Bay City's shifted SECA liability would entirely disregard the requirement under Paragraph 45 that Bay City demonstrate that CMS ERM was the supplier during the transition period. *Id.* at 10-11.

409. According to its own representations, Bay City is certain that it paid CCG – not CMS ERM – for power deliveries during the transition period. *Id.* at 11. Bay City also concedes that if there was a problem or question regarding the power that was supplied to Bay City during the transition period, Bay City representatives would contact CCG

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

representatives – not CMS ERM representatives. *Id.* CMS ERM maintains that such facts clearly indicate that it did not serve as Bay City's supplier during the transition period. *Id.* at 12. CMS ERM notes that OATi tags for the transition period also clearly illustrate that CMS ERM was not the shipper. *Id.* CMS ERM concludes that because it was not Bay City's supplier during the transition period, Bay City has no basis under Paragraph 45 to shift its SECA liability to CMS ERM. *Id.*

410. Arguing that "contractual privity" is irrelevant for purposes of assigning SECA liability in this proceeding, CMS ERM argues that it is more appropriate to assign liability based on who benefits under a given contract from the elimination of RTORs, rather than who nominally held the contract. *Id.* at 12.

411. CMS ERM remarks that since witnesses for CMS ERM, Bay City and CCG have all testified that CCG – not CMS ERM – received all revenues from Bay City through the transition period for the provision of electric service pursuant to the contract, it is clear that regardless of who nominally held the Bay City contract, there is no basis to shift SECA charges to CMS ERM. *Id.* at 12-13.

412. Because the record shows that CMS ERM was not supplying power to MSCPA or Bay City during the transition period, CMS ERM argues that it would be a "textbook violation" of both the filed rate doctrine[90] and the rule against retroactive ratemaking91 to allow MSCPA or Bay City to shift SECA to CMS ERM. *Id.* at 13-14. Specifically, CMS ERM explains that because the SECA charge did not exist, was not approved, and was not on file when CMS ERM rendered past service to MSCPA and Bay City, any SECA charges imposed on CMS ERM would clearly violate the doctrine and rule.[92] *Id.* at 14.

413. CMS ERM explains that it paid the RTORs associated with its MSCPA and Bay City power supply agreements during the test period. *Id.* at 14. However CMS ERM avers that it received no benefits from the elimination of RTORS because this took place

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[90] The filed rate doctrine "forbids a regulated entity [from] charg[ing] rates for its services other than those filed with the appropriate regulatory authority." CMS ERM IB at 14 (quoting *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981)).

[91] The rule against retroactive ratemaking prohibits the Commission from allowing or initiating rates that collect again for service in a past period. CMS ERM IB at 14 (citing *Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251 (1951); *Associated Gas Distributors v. FERC*, 898 F.2d 809, 810-11 (D.C. Cir. 1990)).

[92] As additional support for this position, CMS ERM cites *Pacific Gas & Electric Co. v. FERC*, 373 F.3d 1315, 1320 (D.C. Cir. 2004), which held that charges assessed to past jurisdictional services violate the filed-rate doctrine or the rule against retroactive ratemaking.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

after CMS ERM assigned its contracts to CCG. *Id.* The imposition of new costs based on prior transactions, argues CMS ERM, is prohibited. *Id.* at 14-15.

414. CMS ERM challenges Bay City's initial brief for failing to reference any evidence, testimony, or arguments suggesting that CMS ERM supplied Bay City with power during the transition period. CMS ERM RB at 16. Similarly, there is no evidence establishing CMS ERM as the shipper with respect to power supplied to Bay City during the transition period. *Id.* Reemphasizing Bay City's consent to the assignment of its power supply contract, CMS ERM argues that Bay City cannot suddenly change its position and claim indifference as to who holds the contract. *Id.* at 18.

415. CMS ERM refutes CCG's argument that it served merely as CMS ERM's agent during the transition period, pursuant to a Servicing and Back-to-Back Agreement dated April 1, 2003. *Id.* at 19. CMS ERM explains that the governing law of Michigan provides for an implied contract "where the intention is not manifested by direct or explicit words between the parties, but is to be gathered by implication or proper deduction from the conduct of the parties, language used or things done by them, or other pertinent circumstances."[93] *Id.* at 20. Applied to the instant case, CMS ERM notes that all parties acted throughout the transition period as if Bay City had signed a formal consent to the assignment of its power supply contract. *Id.* at 20-21. This behavior effectively terminated the Back-to-Back Agreement and formed an implied contract between CCG and Bay City. *Id.* at 21. CMS ERM contends that even if the Back-to-Back Agreement were still in effect, the agreement does not allow CCG to collect and keep all of the revenue generated from supplying power to Bay City without being responsible for any of the expenses related to providing power to Bay City, such as the SECA charges. *Id.* at 21-22.

American Electric Power Service Corporation

416. AEP argues that CCG has not provided a sufficient showing to support a shift-to-shipper claim pursuant to Paragraph 45 of the Commission's Order. AEP/Exelon IB at 60.

417. AEP explains that while the Commission set forth strict criteria to allow for a LSE to shift its SECA charges to its shipper, it did not expressly provide for a similar opportunity whereby shippers could shift their SECA liability to their upstream suppliers by way of a "ripple" claim. *Id.* at 61. Accordingly, AEP maintains that the pursuit of "ripple" claims should not be permitted. *Id.*

418. In the alternative, AEP argues that if ripple claims are permitted, they must

[93] R.G. Moeller Co. v. Van Kampen Constr. Co., 57 Mich. App. 308, 312 (1975); Tustin Elevator Lumber Co. v. Ryno, 373 Mich. 322, at 330 (1964).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

conform to the express requirements of the November 17 Order. *Id.* at 61. AEP's witness Mr. Bethel sets forth the following elements of a successful claim (1) the party asserting the claim must be a LSE that is subject to the SECA charges; (2) the claimant must show that it entered into a bundled pricing contract for delivered power, beginning prior to November 17, 2003 and extending into the transition period (December 1, 2004 to March 31, 2006); (3) the claimant must demonstrate that the shipper previously had to pay a RTOR that has since been eliminated; (4) the claimant must show that the shipper is still being compensated for the now-free service through bundled charges under the existing contract for delivered power with the LSE. *Id.* AEP proceeds to argue that CCG's attempts to shift $809,635 in SECA charges to AEP must be rejected because CCG is not a LSE, and thus does not meet the Commission's express criteria for bringing a shift claim. *Id.* 61-62. Moreover, in its Reply Brief, AEP challenges CCG's contention that the Order on Rehearing did not actually mean what it said and should be interpreted based on "context" and general "policies." AEP/Exelon RB at 38. AEP argues that CCG's failure to seek rehearing back in late 2003 to contest the meaning of the Order precludes such a claim now. AEP/Exelon RB at 38.

419. AEP contends that the factual case underlying CCG's ripple claim is incomplete, noting that CCG's own expert, Mr. Meyer, characterizes his analysis as "not exhaustive." AEP/Exelon IB at 63. Moreover, AEP criticizes CCG for failing to carry the burden of proof in supporting its own case and denying that such a burden even exists. *Id.* Once the Michigan LSEs set forth a *prima facie* case to shift their SECA to CCG, the burden of going forward shifts to CCG to prove otherwise. *Id.* at 63-64.

420. Although CCG made the general assertion that AEP benefited from the Commission's elimination of RTORs, it failed to provide a transaction-by-transaction demonstration to show that its arrangements with AEP were the source of supply to the Michigan LSEs. *Id.* at 64. Furthermore, despite his numerous exhibits, testimony and work papers, CCG's expert failed to provide evidence that clearly sets forth any of the claimed benefits for AEP. *Id.* at 64-65. Accordingly, AEP argues that CCG's ripple claims should be dismissed. *Id.* at 64.

421. According to AEP, Mr. Meyer's analysis consists of identifying two transaction confirmations that seem to fit the Commission's criteria for a shift-to-shipper claim, and then tallying up the maximum delivery obligations between AEP and CCG for each transaction. *Id.* at 65. However, AEP criticizes Mr. Meyer for failing to make any adjustments to the amount of power that AEP was obligated to deliver, relying instead on the mere assumption that all of the power was physically delivered. *Id.*

422. AEP also criticizes Mr. Meyer for his contradictory statement regarding the use of OATi tag data. *Id.* at 65-66. Specifically, although Mr. Meyer averred that CCG's analysis was based on the available OATi tag data, he later disavowed relying on OATi tag data for any part of his analysis. *Id.*

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Discussion/Findings/Conclusions – Group One

MSCPA's Claim Against CCG

423. As a LSE under a long-term, bundled contract for delivered power that continued into the transition period, MSCPA filed a "shift-to-shipper" claim against its contractual counterparty, CCG, pursuant to Paragraph 45 of the Commission's November 17 Order. On March 6, 2006, MSCPA filed the supplemental direct testimony of Mr. White, who argued that CCG should be responsible for $884,355 of SECA charges assessed against MSCPA. Ex. MSC-2A at 14:2-6. As discussed below, MSCPA has made the requisite showing under Paragraph 45 to shift its SECA liability under its long-term contract with CCG.

424. There is no disputing that the agreement between CCG and MSCPA constitutes an existing contract for delivered power that continued into the transition period. Running from January 1, 2002 through December 31, 2008, the bundled contract at issue involves the sale of delivered power into the Midwest ISO transmission pricing zone in which MSCPA's load is located (METC). Ex. S-3 at 26 (§IV.A.3). Although MSCPA initially entered into the contract with CMS ERM, the power delivery arrangement was effectively assigned to its successor, CCG, by letter dated February 14, 2003. Ex. MSC-2A at 3:15-19.

425. CCG is undisputedly the supplier under the terms of the Agreement, as illustrated by the bilateral nature of the contract at issue, coupled with CCG's own concession on this point. *See* Tr. at 1863-1865. The issue to be resolved; however, is whether CCG is appropriately deemed to be MSCPA's supplier in light of the chain of supply that exists outside of the Agreement.

426. The LSEs advocate a specific interpretation of the term "supplier," one that refers solely to the LSE's contractual counterparty for delivered power. In contrast, CCG argues that a supplier, for purposes of a shift-to-shipper claim, can be any party in the chain of supply from source to sink. Moreover, CCG argues that the responsible party is the party who requests T&O transmission service across a relevant seam between PJM and MISO, thereby incurring RTORs. CCG's argument is ultimately unpersuasive. Notably, CCG is free to choose its own method of sourcing the power required for delivery pursuant to the contract. Tr. at 1867:12-16. In contrast, MSCPA plays no role in this upstream supply process and thus has only one supplier as defined by the terms of its contract: CCG. *Id.* at 1868:11-15. Thus, the chain of supply effectively stops with the LSE's contractual counterparty for purposes of a shift-to-shipper claim.

427. Although not specifically articulated by the Commission's orders, at the hearing,

parties were allowed to defend against a shift-to-shipper claim by asserting "ripple claims." The parties claimed that they were not the beneficiaries of the elimination of the RTORs but that their shipper was. The assertion of such defenses was deemed fair. Accordingly, the initial shift in SECA liability by MSCPA does not foreclose the possibility of a subsequent "ripple" shift to an upstream supplier shown to be the actual beneficiary of the Commission's elimination of RTORs. However, the filing of such ripple claims is an obligation that is appropriately left to the upstream supplier's contractual counterparty, which is CCG – not MSCPA.

428. CCG and MSCPA differ in their interpretations of the word "transaction" in the following phrase of Paragraph 45: "we will allow LSEs under existing contracts for delivered power that continue into the transition period to demonstrate that the supplier is the shipper for such transactions and to propose that the supplier be required to pay the SECA for that portion of the LSEs load served by the contract." *See* November 17 Order, 105 FERC ¶ 61,212 at P 45. CCG advocates a broad interpretation of the term "transactions," one that extends beyond the contract and encompasses all sales and purchases from the source of the power to its sink. However, MSCPA is correct in pointing out that CCG's interpretation runs contrary to the plain meaning of the order. Common English usage supports the finding that the Commission's use of the word "such" to modify "transactions" indicates a referral back to a previous word or idea: namely, the "existing contracts."

429. The plain meaning of a contract for "delivered" power supports MSCPA's contention that CCG acted not only as its supplier, but also as its shipper. MSCPA correctly points out that, under the contract, CCG is responsible for arranging the transmission of the power to MSCPA's delivery point at METC. Ex. MSC-3A at A-7, A-16. Indeed, CCG's own witness conceded as much on cross examination. Tr. at 1865:19-23, 1867:6-11. Regardless of whether MSCPA made the actual transmission arrangement, the contract clearly indicates that CCG was responsible for the delivery of power.

430. CCG incorrectly asserts that MSCPA's interpretation of "shipper" renders superfluous the requirement in Paragraph 45 that the LSE "demonstrate that the supplier is the shipper." In a bilateral contract for delivered power, the distinction between a "supplier" and a "shipper" is apparent in contracts that expressly involve third parties who have assumed responsibility for delivery. Accordingly, MSCPA has not stripped the two terms of independent meaning. Rather, through reliance on the contracts at issue, MSCPA has successfully demonstrated that CCG was both its supplier and shipper, as required under Paragraph 45. *See* November 17 Order, 105 FERC ¶ 61,212 at P 45.

431. MSCPA has provided irrefutable testimony demonstrating that the elimination of the T&O rates had no impact on its contract price with CCG. Ex. MSC-2A at 7:5-14. Furthermore, the language of the contract indicates that its price included the cost of

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

transmission because the seller expressly took "responsib[ility] for any transmission losses and loss charges relating to the transmission of Power to the Delivery Point(s)." Ex. MSC-3A at A-7 (Art. III, §3.1). At the time the contract was entered into, it is presumed that the price included the RTORs as a component of the cost of transmission. Subsequent to the elimination of the RTORs, the contract price remained fixed and MSCPA continued to pay a charge that no longer existed. MSCPA's payment of SECA on top of this charge is clearly unjust and unreasonable. This is precisely the inequity that the Commission intended to address when drafting Paragraph 45.

432. CCG's argument that it received no benefit from the elimination of the RTORs is meritless. Regardless of where CCG obtained the power used to service MSCPA, the fact remains that it charged MSCPA the contract price which included the cost of transmission and presumably incorporated the RTORs that were in place at the time the contract was formed. Unlike MSCPA, CCG did not have to pay a RTOR after the rate had been eliminated, thereby indicating that CCG did benefit.

433. To ensure consistency with the principles of cost-causation, MSCPA must be given the opportunity to shift its SECA liability to its contractual supplier. If the supplier can subsequently prove that its upstream supplier paid the transmission costs and was thus the true beneficiary of the Commission's elimination of RTORs, a "ripple" claim may be filed to ensure that the downstream supplier (in this instance, CCG) is not charged unjust and unreasonable rates. But to require that MSCPA file its shift claim against an upstream supplier with whom it had no contract is both inefficient and unfair. With superior knowledge of its own contractual arrangements, CCG is the more appropriate party to file these upstream shift claims.

434. Through the use of 2002 test period data, MSCPA asserts that $884,355 of its total $995,518 SECA liability should be shifted to CCG. Ex. MSC-2A at 11-14; MSC-5. This amount must be recalculated according to the conclusions reached above concerning the compliance filings.

435. The parties are in dispute over whether MSCPA used all of the power supplied by CCG to serve its load. Based on its response to a data request issued by CCG, MSCPA sold 57,354 MWh of power to third parties in 2005. Tr. 1479:12-14. According to CCG, this fact proves that a portion of the 262,800 MWh of power delivered by CCG pursuant to the contract was not needed to serve MSCPA's load. Emphasizing that the shift provision of Paragraph 45 applies only to power being used to serve load, CCG requests a 21.8 percent proportionate reduction in its shifted SECA liability.[94] Although MSCPA maintains that the third-party sales at issue originated from its own generating units, it has not submitted any evidence to substantiate its contentions. Additionally, MSCPA

[94] CCG derives this figure by dividing 57,354 MWh by 262,800 MWh.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

fails to offer an economic rationale underlying its supposed decision to use delivered power from CCG solely to serve its load while its own generation for purposes of third party sales. Accordingly, subject to any recalculations from other findings in this Initial Decision, CCG is entitled to a 21.8 percent proportionate reduction in its shifted SECA liability.

436. On April 1, 2005, the Midwest ISO implemented its Day 2 markets, which allowed power marketers and other parties to purchase power entirely within MISO at locational marginal prices. Tr. 1803:4-25. Mr. Meyer testified that, prior to the implementation of the Midwest ISO Day 2 markets on April 1, 2005, CCG purchased power under short-term contracts (unrelated to CCG's long-term confirmations with AEP) to meet its obligations to the Michigan LSEs. Ex. CCG-6 at 56:23-57:2. CCG agrees that it was the shipper of these particular transactions because it served as the transmission customer that crossed the relevant seam from PJM into MISO and thereby benefited from the Commission's elimination of RTORs. CCG IB at 58. Through the use of OATi tag data, CCG determined its maximum SECA liability for all transactions to the Michigan LSEs to be $313,123 (a significant portion of this amount is allocated to MSCPA in Ex. CCG-26). Ex. CCG-6 at 57:17-23. However, CCG notes that the implementation of the Day 2 markets greatly reduced the amount of imports from PJM into the Midwest ISO because these imports were no longer economically necessary. CCG IB at 59.

437. CCG is correct in concluding that the TOs are not entitled to collect SECA charges for recovery of revenues for transactions associated with the Day 2 Markets. Because the power transactions within the Day 2 markets are internal to MISO and do not cross over the PJM seam, they would not have been subjected to rate pancaking through RTORs. As the Commission has stated in Paragraph 44 of its November 17, Order, the collection of SECA was intended "to address revenue losses and potential cost shifts arising from the elimination of rate pancaking." November 17 Order, 105 FERC ¶ 61,212 at P 44. Accordingly, the transmission owners are not entitled to collect SECA for transactions within the Day 2 markets because the transmission of power never crossed the border into PJM, and thus, the shipper never incurred a RTOR. Again, this also presents an evidentiary issue. CCG has not demonstrated that it sourced the power to MSCPA from the Midwest ISO Day 2 markets. It made this assertion, but failed to substantiate it. Therefore, CCG is liable for the entire amount.

438. Accordingly, it is found that MSCPA can shift most of its SECA to CCG (the SECA sought to be shifted was $995,518 which will need to be recalculated based on the findings in this ID, minus 21.8 percent as found above).

The Six Michigan Cities' Claim Against CCG

439. The Six Michigan Cities assert that the entire amount of their SECA obligations should be shifted to their supplier under their respective contracts for delivered power.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Ex. S-3 at 27 (§ IV.A.6).

440. There is no disputing that the members of MPPRA entered into a fixed price requirements contract with CMS ERM for the sale of delivered power, extending from December 2001 through December 31, 2006. *Id.* The MPPRA contracts were then sold by CMS to CCG, pursuant to an agreement that became effective February 12, 2003. *Id.* Under the terms of the contract (which was ultimately extended through 2011), CCG was responsible for the scheduling and delivery of power to the MPPRA members. Ex. MTDU-54 at §§ 2, 4, 6 and Exhibit A. Remarking that the MPPRA contracts expressly hold CCG liable for "all costs, liabilities and charges of any kind relating to, or arising from, the supply and delivery of capacity and energy to any Consumers Energy interface," the MPPRA members filed a claim, pursuant to Paragraph 45, to shift their entire $742,459 in SECA charges to CCG. Ex. MTDU-54 at §12, S-3 at 27 (IV.A.6). As discussed below, and based on the same conclusions reached above in the analysis of MSCPA's shift-to-shipper claim against CCG, the record supports MPPRA's recovery of SECA from CCG.

441. It is also undisputed that Bay City entered into a fixed price requirements contract with CMS ERM for the sale of delivered power, extending from January 1, 2002 through December 31, 2006. S-3 at 27 (§IV.A.8). The Bay City contracts were then sold by CMS to CCG, pursuant to an agreement that became effective February 12, 2003. Ex. CMS-4 at 4:9-13; Ex. CMS-5. Although Bay City consented to the assignment of its contract from CMS to CCG, CCG maintains that the formal execution of the assignment never took place. Ex. MTDU-59; CMS-4 at 7:22-23; Tr. 2123:14-17. Six Michigan Cities at 4, 12. As discussed below, the absence of such a formality does not preclude the finding of a contractual relationship between Bay City and CCG. The Bay City contract contained the same proviso as the MPPRA contracts, *i.e.*, that CCG would be liable for "all costs, liabilities and charges of any kind relating to, or arising from, the supply and delivery of capacity and energy to any Consumers Energy interface." Ex. MTDU-54 at 10 (§12). Based on the language of this contract, Bay City filed a claim, pursuant to Paragraph 45, to shift their entire $655,236 in SECA charges to CCG. As discussed below, and based on the same conclusions reached in the analysis of MSCPA's shift-to-shipper claim against CCG, the evidence in the record supports Bay City's shift-to-shipper claim against CCG.

442. Bay City and the MPPRAs are correct in their assertions that, for purposes of their shift-to-shipper claims, the relevant supplier in these proceedings is the contractual counterparty responsible for the delivery of the power. As discussed in the previous section, a LSE's supplier is the party explicitly referenced in the contract. Because the contracts at issue are bilateral agreements with CCG, CCG is clearly the supplier. Any upstream entities that may have provided power to CCG cannot be deemed to be the suppliers of the Six Michigan Cities; rather, they are suppliers to CCG. Should CCG successfully demonstrate that these upstream entities were the primary beneficiaries of

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

the Commission's elimination of RTORs, CCG is free to file a "ripple" claim. Nevertheless, the initial shift must begin with the LSE's claim against its contractual supplier.

443. The plain language of Paragraph 45 supports the conclusion that a LSE's supplier is its contractual party for delivered power. For the reasons discussed above, the Commission's use of the phrase "shipper such transactions" must refer back to the phrase "contracts for delivered power." *See* November 17 Order, 105 FERC ¶ 61,212 at P 45. This construction clearly demonstrates the Commission's intent that a LSE initiate its shift claim against its contractual supplier, and not against other upstream suppliers with whom it had no contractual relationship.

444. CCG's opposing argument that the word "such" refers to absent rather than proximate language is inconsistent with common English usage.

445. The Six Michigan Cities have successfully demonstrated that CCG acted as the shipper pursuant to the requirements of Paragraph 45 by pointing out the undisputed fact that CCG was responsible for ensuring that power arrived at or within the METC zone of MISO and was then scheduled on to the Six Michigan Cities. Additionally, the Six Michigan Cities provide testimony persuasively demonstrating that a "contract for delivered power" necessarily includes two distinct requirements: a power-shipper sub-requirement and a power-supplier sub-requirement. Ex. MTDU-70 at 15:21-26. Because CCG is the only contractual counterparty to the Cities in the bilateral agreement at issue, CCG is both the shipper and the supplier.

446. Because the Six Michigan Cities were locked into fixed price contracts with CCG, they were unable to benefit from the Commission's elimination of RTORs. Given that they were still paying the contract price of their contracts with CCG, the imposition of SECA on the Cities constitutes double rate paying and is unjust and unreasonable. Therefore, the Six Michigan Cities must be permitted to shift their SECA liability to the party in the chain of supply with whom it had a contractual relationship for the delivery of power, namely, CCG.

447. CCG's contention that it was not the beneficiary of the Commission's elimination of RTORs does not preclude the Six Michigan Cities from filing their shift claim against CCG. Indeed, the Six Cities correctly note that the Commission's November 17 Order did not reference a benefits test as part of the requirements for a successful shift-to-shipper claim. CCG's reliance on this "phantom" element is essentially an attempt to shift the burdens of proof. The burden of proof as stated in the now famous Paragraph 45 is that LSEs demonstrate that "the supplier is the shipper;" nothing else is required. The burden on the LSEs was not to demonstrate that the supplier benefited since the Commission assumed the LSE was the one paying the bundled price (which included the RTOR) and the SECA. CCG's attempt to shift the burdens is contrary to the

Commission's goal of mitigating the LSE's burden.

448. Notwithstanding the discussion in the previous paragraph, CCG's argument that it received no benefit from the elimination of the RTORs is meritless. Regardless of where CCG obtained the power used to service the Six Michigan Cities, the fact remains that its contract price included the cost of transmission, as evidenced by the express clause holding CCG liable "for all costs, liabilities and charges of any kind relating to, or arising from, the supply and delivery of capacity and energy to any Consumers Energy interface." Ex. MTDU-54 at 10 (§12) (MPPRPA member sample contract); MTDU-58 at 10 (§12) (Bay City contract). Because the contracts were formed prior to the Commission's elimination of the RTORs, these charges were included in the price as part of the cost of transmission. However, subsequent to the elimination of the RTORs, the contract price remained fixed, and the Six Michigan Cities continued to pay a charge that no longer existed. CCG, on the other hand, did not have to pay the RTOR but was nevertheless pocketing this charge through the price of its fixed contract. Thus, CCG did benefit and it is liable for the entire shift-to-shipper claim of the Six Michigan Cities.

449. The Six Michigan Cities unveiled a new set of calculations in their Initial Brief that purport to shift $546,000 of SECA responsibility to CCG based on an extrapolation of CCG's conceded liability of $313,123 for all the Michigan LSEs (a portion of this amount is allocated to the Six Michigan Cities, including Bay City in Ex. CCG-26). Six Michigan Cities IB at 28. Unsupported by evidence in the record, these calculations must be rejected and dismissed.

450. Accordingly, it is found that the Six Michigan Cities can shift their SECA to CCG. The amount must be established pursuant to the findings in this Initial Decision.

CCG's Claim Against CMS & Bay City's Claim Against CMS

451. Bay City is a municipality-owned utility located in the Michigan Electric Coordinated Systems (MECS) portion on MISO. Ex. S-3 at 27 (IV.A.8). On May 7, 2001, Bay City entered into a Requirements Power Supply Agreement with CMS Marketing, Services, and Trading Company (CMS), extending from January 1, 2002 through December 21, 2006. Ex. MTDU-58; S-3 at 27 (§IV.A.8). Pursuant to a purchase and sale agreement that became effective on February 12, 2003, CMS Energy Market Resource (CMS ERM) sold its "wholesale electricity to load-serving entity" business to CCG. *See* Ex. CMS-4 at 4:9-13.. As part of that sale, CMS ERM sold its power supply agreements with MSCPA and Bay City to CCG. Ex. MSC-2 at 3:15-19; Ex. MTDU-50 at 36:16-17.

452. The record indicates that Bay City consented to the assignment of its power supply agreements from CMS ERM to CCG on November 21, 2003. Ex. CMS-7; MTDU-50 at 36 (citing MTDU-58). Furthermore, the party that billed Bay City for power deliveries

into the transition period was CCG, not CMS ERM. Tr. at 1812:15-18; 1896:17-1897:1. In turn, CCG received payments for these deliveries and did not remit any of this payment back to CMS ERM. Tr. at 1813:2-9; CMS-4 at 9:23-10:1; Tr. at 1898:17-20. Finally, neither Bay City nor CCG have provided any evidence suggesting that CMS ERM supplied power to Bay City during the transition period. Collectively, these facts clearly indicate that CCG effectively became Bay City's supplier for the period of time extending into the transition period.

453. CCG is unpersuasive in its argument that Bay City never executed and delivered the assignment of its contract from CMS ERM. The omission of such a formality does not bar the finding that a *de facto* contractual relationship existed between Bay City and CCG for the supply of power into the transition period. This is the relationship contemplated by the Commission for purposes of a shift-to-shipper claim. The party who nominally holds the power supply contract cannot be deemed a true "counterparty" if it no longer retains the obligation to supply power. In fact, Paragraph 45's requirement that the LSE "demonstrate that the supplier is the shipper" becomes completely inapplicable as applied to CMS ERM because CMS ERM was not involved in the delivery of power. *See* November 17 Order, 105 FERC ¶ 61,212 at P 45. Any claims that CCG wishes to make against CMS ERM must be brought in another forum; they are not appropriately brought under Paragraph 45 because CMS ERM was not physically involved in the power transactions. The power purchase agreements as to CMS ERM and Bay City were assigned. Thus, CCG *de facto* became the "supplier is the shipper" for purposes of Paragraph 45 of the Commission's Nov 17 Order. As to the whether CMS ERM must indemnify CCG pursuant to their back to back agreement (or agency relationship) is not an issue before this forum.

454. This ruling is consistent with the discussion above. Although it is true that a shift-to-shipper claim must begin at the level of the contract between a LSE and its supplier in accordance with Paragraph 45, an actual business relationship must also exist between the contractual parties for the delivery of load. Where no such relationship exists, and it is clear that parties to the contract are listed only nominally, it becomes necessary to look beyond the formality of the contract to determine the *de facto* counterparty to the contract. With respect to the nominal Bay City/CMS ERM contract, the "true" counterparty is clearly CCG. This ruling must be applied narrowly, and it is based on these particular set of facts.

455. Therefore, it is concluded that SECAs cannot be shifted to CMS ERM based on the findings above.

CCG's Claim Against AEP

456. It is undisputed that CCG had two confirmations with AEP for the supply of power at an "into MECS" delivery point. These confirmations were entered into prior to

November 17, 2003 and extended through the transition period. On April 29, 2003, Constellation Power Source, Inc. (the predecessor of CCG) contracted with AEP to purchase 50 MW per hour of electricity during off-peak hours at a delivery point of Into Michigan Electric Coordinated Systems, for a period extending from June 1, 2003 through December 31, 2004. Ex. At 25-26 (S-3.IV.2). On October 8, 2003, Constellation Power Source, Inc. (the predecessor of CCG) contracted with AEP to purchase 50 MW per hour of electricity during peak hours at a delivery point of Into Michigan Electric Coordinated Systems, for a period extending from January 1, 2005 through December 31, 2005. *Id.*

457. From the 50MW blocks of power referenced above, CCG shapes the power to meet the requirements of the Michigan LSEs pursuant to the respective power supply contracts. Ex. CCG-6 at 55:2-5. Notably, CCG receives the power from AEP at the same delivery point used to service the sale of power to the Michigan LSEs.

458. Through the use of OATi tag data, CCG has successfully demonstrated that the power sinking with the Michigan LSEs in the MECS region of the Midwest ISO was sourced by AEP from within PJM. Tr. 2077:7-10. Additionally, these data confirm that AEP was the transmission customer that obtained transmission service across the relevant seam from PJM into the Midwest ISO. *Id.* at 2071: 18-21. Collectively, these findings indicate that AEP was the party in the chain of supply to the Michigan LSEs that was the shipper that benefited from the Commission's elimination of RTORs.

459. Despite the conclusion that AEP initiated the supply of power that ultimately sank to the Michigan LSEs, the separate contractual agreements between AEP/CCG and CCG/Michigan LSEs support the finding that AEP served only as CCG's shipper. As there was no contractual relationship or understanding between AEP and the Michigan LSEs, AEP was not a shipper to the Michigan LSEs. Thus, according to the language of Paragraph 45, the Michigan LSEs could not have brought their shift-to-shipper claims against AEP. As discussed above, the only party to whom the Michigan LSEs could shift their SECA liability was CCG.

460. However, based on the valid argument that it was AEP – and not CCG – that benefited from the Commission's elimination of RTORs, a general sense of fairness requires that the SECA charge ultimately rest with AEP via a "ripple" claim brought by CCG. AEP, in turn, argues that ripple claims should not be permitted because the Commission's did not articulate a mechanism whereby shippers could shift SECA liability to their upstream suppliers. While true that the Commission's orders do not explicitly reference the concept of ripple claims, such claims have been deemed fair throughout the course of the hearing. Thus, the contention that an apparent loophole in the Commission's order exempts AEP from SECA liability must be rejected. This is clearly consistent with the Commission's underlying intent when drafting Paragraph 45: that the beneficiary of elimination of the RTORs is the appropriate party to pay the

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

transitional SECA charge. *See* November 17 Order, 105 FERC ¶ 61,212 at P 45. Having demonstrated through the use of OATi data that it had a bundled power contract with AEP for transactions that sank with the Michigan LSEs, while its "shipper" no longer had to pay RTORs. Thus, CCG should not be left with the SECA responsibility; to do so would be unjust and unreasonable.

461. Based on the same methodology used by the transmission owners in their compliance filings, CCG determined that AEP should be liable for $809,635 in shifted SECA charges. Ex. CCG-6 at 56:13-18. Notably, CCG is not seeking to "ripple" the entire shift claim brought by the Michigan LSEs. In fact, CCG admits to meeting a portion of its power supply obligations to the Michigan LSEs through short-term contracts that were separate from the long term confirmations with AEP. Ex. CCG-6 at 56:23-57:2. As the transmission customer that crossed the relevant seam from PJM into the Midwest ISO, CCG conceded to being the beneficiary of the Commission's elimination of RTORs for these particular transactions, appropriately accepting SECA liability in the amount of $313,123 for all the Michigan LSEs. *Id.* at 57:20-23.

462. AEP contends that because CCG is not a LSE, it is ineligible to file a ripple claim. Not only does this argument lack merit, it also clearly illustrates AEP's poor understanding of the nature of the claims at issue. As CCG correctly points out, the fact that it is not a LSE is irrelevant because CCG is not making a shift-to-shipper claim against AEP. Rather, it is defending itself against the Michigan LSEs' shift claims by demonstrating that AEP was the supplier. CCG RB at 26.

463. Although AEP makes the repeated argument that CCG failed to provide sufficient evidence to support its "ripple" claim, it offered none of its own evidence to refute that of CCG's. Specifically, AEP has made no attempt to disprove (or even deny) that it was the transmission customer that delivered power across the relevant seam between PJM and the Midwest ISO, thereby benefiting from the elimination of RTORs.

464. Furthermore, AEP made only a feeble attempt to discredit the testimony of CCG's witness, Mr. Meyer, through the vague assertion that his testimony was "incomplete." CCG responded by emphasizing that Mr. Meyer used OATi data that clearly identified the Michigan LSEs as the sink for the transactions at issue. Tr. at 2064:25-2065:2; 2074:1-4, 2075:5-10; 2077:7-10. Additionally, Mr. Meyer testified that long-term transactions do generally result in physical delivery, thereby illustrating that the power supplied by AEP was actually used to serve the load of the Michigan LSEs. *Id.* at 1917:15-20; 1917:25-1918:1. According to the record, there is nothing facially incomplete about Mr. Meyer's testimony. Without referencing any specific inaccuracies in Mr. Meyer's methodology, AEP necessarily fails in its attempt to challenge this testimony.

465. Finally, AEP's claim that CCG did not establish a *prima facie* case against it must

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

be rejected. The record indicates that CCG conducted an appropriate analysis of OATi tag data, which collectively revealed that AEP was the transmission customer that sourced power across the PJM/MISO sink for ultimate delivery to the Michigan LSEs. Thus, CCG has indeed set forth a sufficient showing to support its "ripple" claim. Accordingly, the burden effectively shifted to AEP. Having failed to introduce any rebuttal evidence to CCG's claim, AEP clearly did not meet this burden.

466. Accordingly, it is found that CCG can shift $809,635 of SECA charges to AEP, subject to any change to the amount based on the above findings.

Parties' Contentions

Quest Energy, L.L.C., WPS Energy Services, Inc.

467. Claiming to have met the Commission's criteria specified in Paragraph 45 of the Commission's November 2003 Order, Quest/ESI seeks to reallocate a portion of its SECA to Mirant Americas Energy Marketing, L.P. (Mirant). Quest/ESI IB at 45.

468. Quest/ESI explains that its suppliers' contract prices for electric power included the cost of delivery and any applicable RTOR charge. *Id.* at 45. Once the SECA was implemented, the supplier who reserved transmission was relieved of its RTOR payments. *Id.* Nevertheless, the SECA charges fell to Quest/ESI as the LSE ($19.6 million total and approximately $17 million for its retail business in Michigan). Therefore, under Paragraph 45 of the Commission's order, Quest/ESI is seeking to shift these charges to its supplier, the party who actually benefited from the elimination of RTORs. *Id.* at 44-45.

469. Quest characterizes itself as an "alternative electric supplier" in Michigan, supplying retail customers with electric power at competitive prices rather than at tariff rates. *Id.* at 45. As a relatively small market player with insufficient credit to make its own long-term purchases of power, Quest procures its long-term supplies by bringing in a creditworthy entity to act as a credit sleeve; ESI served as this credit sleeve. *Id.* at 46.

470. To serve its retail load, Quest states that it negotiated a power supply arrangement with Mirant. *Id.* at 46. Quest describes two separate contracts that were simultaneously executed and that contained identical product specifications. *Id.* The first contract established a relationship between WPS ESI and Mirant, and the second contract established a relationship between Quest and WPS ESI. *Id.* Quest asserts that, when analyzed together, these two contracts establish a contractual link between Quest and Mirant. Quest further explains that this type of credit arrangement is common in the industry. *Id.* Quest contends that it had four power contracts with Mirant (as determined by the contractual link described above) that continued into the SECA transmission

period. *Id.* at 47. According to Quest, it used virtually all of the power supplied by Mirant to serve its retail load. *Id.* at 48.

471. Under the arrangement between Mirant and Quest, Mirant delivered power to the specified "delivery point," specifically the control area named Michigan Electric Coordinated System (MECS). *Id.* at 47. Quest proceeded to use its network service transmission to deliver the power to its retail customers within MECS. *Id.* at 47. Quest states that Mirant obtained the transmission and paid the RTOR for approximately 95 percent of power that was delivered to Quest across the seam. *Id.* at 49. In contrast, WPS ESI, who provided only credit support, reserved no transmission. *Id.* Furthermore, Quest explains that WPS ESI did not appear as a transmission provider in the physical path of any of the OATi data tags that were reviewed throughout the course of discovery. Quest RB at 36. Accordingly, Quest concludes that Mirant is the supplier, the shipper, and the entity that directly benefited from the elimination of RTORs. Quest IB at 49.

472. Contrary to Mirant's contentions, Quest emphasizes that it did not act as ESI's agent for power delivery arrangements. Quest/ESI IB at 48. In fact, Quest remarks that ESI "was involved only rarely, and then only to provide back-up operations." *Id.*

473. Quest seeks to shift $1,295,427 of its $17 million SECA liability to Mirant, based on the amount of load served by the Mirant contracts. *Id.* at 48. Specifically, Quest calculated the proportion of Mirant's supply to Quest's average daily peak demand in MW. *Id.* at 49-50. Further details of this calculation are shown in Ex. QST-25. *Id.* at 50.

474. Quest maintains that it meets the requirement of Paragraph 45 because Mirant served as both its shipper and supplier. *Id.* at 51. Quest contends that because Mirant paid for the transmission to bring the power from the generation source to the Quest sink, Mirant was clearly the shipper. *Id.* Quest reiterates that Mirant held its status as shipper notwithstanding the disconnect between the contractual relationship and the physical scheduling of transactions. *Id.* Specifically, Quest explains that each contract specifies a "delivery point." *Id.* As relevant to the Quest-ESI and ESI-Mirant contracts, the delivery point is MECS. *Id.* However, there is no physical delivery point at MECS. *Id.* That is merely a convenient way of contractually defining the obligations of the parties. *Id.* Physically, the supplier (Mirant) and the LSE (Quest) jointly schedule a transaction from the generator to Quest's sink: MECS.CONS.QEHI. *Id.*

475. By way of analogy to natural gas transportation in which the term "shipper" refers to a transportation customer, Quest defines a "shipper" as a "transmission customer" when applied to electric power delivery. *Id.* at 52. To support this position, Quest explains the Commission's standards of conduct (applicable to both natural gas and electric utilities), suggests that the term shipper equates to a transmission customer. *Id.*

476. Quest contends that a "quasi-contract" exists between Quest and Mirant based on

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

principles of unjust enrichment. *Id*. at 53. Quests sets forth the following elements for establishing a quasi contract based on unjust enrichment: (1) a benefit must be conferred; (2) the recipient must have appreciate on or knowledge of the benefit; and (3) acceptance or retention of the benefit must be such that it would be inequitable for the recipient to retain the benefit without payment. *Id.* at 53-54.

477. Quest asserts that each of the aforementioned elements has been met. *Id.* at 54. As to the first element, Mirant has received the benefit of no longer having to pay the RTOR to transmit power across the seam to meet is obligations to ESI and Quest. *Id.* Additionally, Mirant has benefited from increasing economic opportunities. *Id.* Due to the elimination of RTORs, Mirant is more able to draw from additional resources within PJM without subjecting itself to rate-pancaking. *Id.* As to the second element, Quest asserts that Mirant was aware of the benefits it received. *Id.* This is evidenced by 1) the Commission's orders; 2) Mirant's intervention in this proceeding on October 15, 2004 and December 1, 2004; 3) Mirant's actions and interactions with MISO and PJM in scheduling and paying for power needed to meet its contractual obligations to ESI and Quest. *Id.* Quest notes that the third element is also satisfied because Mirant has kept the benefit of the elimination of ROTRs to itself, whereas Quest has had to pay both the SECA and the RTOR that remains bundled in the price of power. *Id.*

478. Quest/ESI also argues that ESI's "ripple" claim against Mirant is valid. *Id.* at 54. Just as Quest claims to have suffered a financial loss from 'double paying' for transmission (by virtue of having to pay SECA in addition to the RTOR that remains embedded in the bundled price it pays for power delivery), so too has ESI been forced to pay for both the SECA and RTOR. *Id.* at 54-55. Quest explains that ESI purchased a bundled product from Mirant, which was subsequently delivered to Quest at MECS. *Id.* at 55. The price for this power included a RTOR that was bundled into the price. *Id.* It would be unjust and unreasonable, contends Quest/ESI, if ESI were to pay both the SECA and the RTOR. *Id.* Accordingly, ESI asserted a ripple claim against Mirant, requesting a reallocation of SECA. *Id.*

479. Quest/ESI maintains that ESI's ripple claim was filed prior to the March 27, 2006 deadline for the assertion of such claims, thereby giving Mirant sufficient notice of the claim. Quest/ESI RB at 40-41. Quest/ESI further defends the ripple claim by noting that Quest is a wholly-owned subsidiary of ESI and is therefore not required to file its own claim against ESI in order to preserve the validity of the ripple claim. *Id.* at 41.

480. Quest/ESI criticizes Mirant's argument that ESI likely benefited by the elimination of the RTOR because ESI's contracts with Mirant did not require ESI to sell the power it received from Mirant back to Quest. Quest/ESI IB at 56. Quest/ESI remarks that this hypothetical is meaningless because, ESI did, in fact, sell the power that it received from Mirant to Quest. Speculating on what ESI "could have done" is irrelevant. *Id.*

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

481. Quest/ESI discusses the Puget Sound Energy case[95] (cited in Mirant's Initial Brief) and notes how the circumstances in the instant proceeding are markedly different – so much so as to "render the precedent a nullity." *Id.* at 56. Specifically, Quest/ESI remarks that in Puget Sound, the Commission did not make any findings that the underlying contracts were unjust, unreasonable, or otherwise not in the public interest. However, in the instant case the Commission took action against unjust and unreasonable rates by eliminating RTORs. *Id.* at 56. Additionally, Quest/ESI remarks that the ripple claims at issue in Puget Sound involved a large number of non-jurisdictional entities, such that the task of tracing transactions became too difficult. *Id.* at 57. Finally, Quest notes that unlike in the MISO situation, Puget Sound did not involve an ISO or RTO Tariff that gave the Commission jurisdiction over the transmission rates of numerous entities. *Id.*

482. Quest/ESI criticizes Mirant's Initial Brief as misconstruing the stipulation of facts. Quest/ESI RB at 29. Specifically, Quest/ESI accuses Mirant of taking statements out of context to give the false impression that its working relationship with Quest was occasional or casual. *Id.* Quest/ESI points out that although Mirant had previously acknowledged an understanding that the WPS ESI/Mirant contract was based on a credit sleeve arrangement, it conveniently failed to mention this understanding in the Initial Brief. *Id.*

483. Quest/ESI maintains that it made an adequate showing that, based on available OATi tag data, 75 percent of the power that Quest purchased from Mirant came from across the PJM/MISO seam. *Id.* at 39. Moreover, Quest/ESI points out that all of the OATi tag data had been admitted into evidence, and Mirant had every opportunity to conduct its own queries to either verify or refute this calculation. *Id.* Quest/ESI emphasizes that the OATi tag data provide ample evidence to show that Mirant obtained the transmission and was relieved of the obligation to pay the RTOR when the RTOR was eliminated. *Id.* at 39-40. Accordingly, Mirant should pay a portion of the SECA allocated to Quest. *Id.*

484. Quest agrees that if its own SECA obligations are reduced through the course of the instant proceedings, the shifted SECA obligations to Mirant should similarly be reduced. *Id.* at 43. However, Quest strongly disagrees with the "outlandish" contention that Mirant's SECA obligations should be reduced by the amounts that Quest is able to collect from its retail customers. *Id.* Specifically, Quest emphasizes that it has collected only a mere fraction (*e.g.*, $2.9 million) of the $17 million SECA dollars from its retail customers in Michigan. *Id.* Quest asserts that it has had to absorb the remaining SECA charges in order to retain its competitive position in the market. *Id.* at 44. Furthermore, Quest notes that approximately $1 million of Quest's SECA liability should never have

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[95] Puget Sound Energy, Inc. v. All Jurisdictional Sellers, 105 FERC ¶ 61,183 (2003).

been assessed to Quest in the first instance; and thus, there is nothing to offset or reduce. *Id.* Finally, Quest points out that this issue does not fall properly within the Commission's jurisdiction; rather, the Michigan Public Service Commission is the entity that implements rules and regulations governing retail access. *Id.*

485. Quest/ESI defends its methodology for calculating the amount of SECA that should be shifted to Mirant. *Id.* at 45. Specifically, Quest/ESI refutes Mirant's accusation that Quest's witness, Mr. Zakem, used "a loss factor that he completely made up." *Id.* at 46. To the contrary, Quest/ESI notes that Mr. Zakem derived average loss factors by using the actual loss factors utilized by the control area utilities at the time (Consumers and Detroit Edison). *Id.* In response to Mirant's contention that Mr. Zakem did not actually use data from Detroit Edison, Quest/ESI accuses Mirant of using "verbal tricks" during his cross examination to mischaracterize the testimony. *Id.* Nevertheless, at the request of the Presiding Judge, Quest/ESI is willing to obtain the actual loss factors and meter reads to determine the exact amount of SECA dollars that should be reallocated to Mirant. *Id.* Quest/ESI also notes that any recalculation will also necessarily reflect Quest's increased SECA obligation arising out of the compliance filings. *Id.*

Mirant Corporation

486. On behalf of Mirant Americas Energy Marketing (MAEM), Mirant Corporation (Mirant) requests that the Presiding Judge dismiss all shift-to-shipper claims against it. If the Presiding Judge does not dismiss all claims outright, then Mirant asks that each claim be examined individually. Mirant IB at 8.

487. Mirant argues that Quest is ineligible to assert a shift-to-shipper claim against it because the two entities did not have a contract with one another. *Id.* at 8. Mirant states that the Commission's order is manifest that the LSE has to have had a contract with a supplier in order to assert a shift-to-shipper claim; accordingly, Mirant contends that Quest's claim must fail. *Id.*

488. Mirant argues that WPS ESI is not entitled to bring a shift-to-shipper claim against Mirant because it is not a LSE that bears SECA liability and is therefore not eligible to assert such a claim. *Id.* at 8. Mirant further contends that if "ripple" claims are allowed to go forward, then WPS ESI has nothing to ripple because no party (including Quest) filed testimony to assert a claim against WPS ESI. *Id.*

489. Mirant remarks that both Quest and WPS ESI had filed a pleading in a bankruptcy court where they clearly indicated that they had no claims, either directly or indirectly, against Mirant. *Id.* at 9. In these filings, Quest and WPS ESI also conceded that they had no right to payment of SECA charges from Mirant and could not have brought any such claim outside of this bankruptcy case. *Id.* Mirant insists that Quest and WPS ESI cannot

make such a statement in one court while simultaneously prosecuting a SECA claim in another court. *Id.* Mirant characterizes the situation as "being forced to defend a claim that the entities asserting it say does not exist." *Id.*

490. Because Mirant has been dissolved in bankruptcy, Quest and WPS ESI are seeking reimbursement for the SECA charges that they suggest should be allocated directly to Mirant. *Id.* at 10. Mirant accuses Quest and WPS ESI of trying to shift the bankruptcy discharge (and Quest/ESI's failure to assert a claim against Mirant in bankruptcy) to the MISO market participants or the PJM TOs. *Id.* From Mirant's perspective, such a result would be manifestly unfair to the MISO market participants or PJM transmission owners who would have to pay for the debts that cannot be collected from Mirant. *Id.*

491. Despite the non-existence of a contract, Quest's witness uses a course of conduct argument to assert that Mirant had a responsibility to deliver power to Quest. *Id.* at 11-12. Mirant responds that such an argument is only proper if the contract's terms are ambiguous; this was not the case here. *Id.* at 12.

492. Quest attempts to bolster its course of conduct argument by introducing testimony showing that Quest employees communicated with Mirant employees about scheduling issues and about liquidated damages. *Id.* at 12-13. However, Mirant was under the impression that Quest was acting as WPS ESI's agent to deal with these issues, as was permitted under the contract between WPS ESI and Mirant. *Id.* Mirant emphasizes that these communications did not form an agreement because there was never any meeting of the minds to do so. Mirant always understood that WPS ESI was its counterparty and that it only had obligations to that entity. *Id.*

493. Mirant also argues that even if the Presiding Judge finds that it had a contract with Quest, Quest is still precluded from recovering SECA from Mirant because it failed to present evidence indicating that Mirant was the "shipper." *Id.* at 14. Specifically, Mirant notes that neither Quest nor WPS ESI has introduced any documentary evidence to show that Mirant arranged for transmission or, assuming Mirant had done so, that any transmission arranged by Mirant was related to any of the contracts at issue in this case. *Id.* Additionally, Quest never submitted any OATi tags into evidence that could demonstrate the source of power. *Id.* at 15.

494. As a second argument in the alternative (assuming a contract is found to exist), Mirant contends that Quest's calculation of load served by its contracts is not correct. *Id.* at 15. Despite two different calculation attempts by Quest, Mirant asserts that Quest has not made a proper showing of the amount that could be shifted. *Id.* In the first set of calculations, Quest's expert used forecasted peak demand for the next day and equated the forecast with Quest's load. The problem with this approach, Mirant claims, is that the purchases based on the forecast are only "a best guess estimate" that can be inaccurate given a change in the forecasted weather conditions *Id.* at 15-16. In the second set of

calculations, Quest's expert attempted to measure load as the amount of energy consumed by an end-user. However, Mirant states that the expert did not weight the area meters but instead "completely made up" the loss factor that was used in the calculation. *Id.* at 16.

495. Mirant's witness, Mr. Reich, performed his own calculations in which he claims to have relied on a more accurate measurement to determine load. *Id.* at 18. Based on the data that Quest/ESI submitted in discovery, Mr. Reich determined the amount of energy WPS ESI provided to Quest from December 2004 through May 2005. *Id.* He proceeded to calculate the amount of energy that Mirant supplied to WPS ESI under the contract. He then calculated an "energy allocation factor" by dividing the amount of energy Mirant supplied by the amount of energy that WPS ESI supplied. *Id.* By multiplying this allocation factor by Quest's SECA charges, Mr. Reich concluded that the maximum amount of Quest's SECA liability that Mirant should pay is $1,089,340. *Id.*

496. Mirant also argues that "ripple" shift-to-shipper claims are not provided for in the November 17 Order and were not specifically contemplated by the Commission. *Id.* at 19. In fact, Mirant cites instances in the past where the Commission has denied ripple claims (*e.g.*, *Puget Sound Energy, Inc.*, 105 FERC ¶ 61,183 at P 56). *Id.* at 20. Moreover, Mirant characterizes ripple claims as "fundamentally unfair" because the Commission lacks jurisdiction over certain participants in the market. *Id.* at 20.

497. Mirant also argues that allowing ripple claims presents logistical difficulties because power can be bought and sold 10 times between the generator and the LSE with a SECA liability. *Id.* at 20. When trying to trace each transaction back, each purchase from a non-jurisdictional entity would break the chain and leave the non-jurisdictional entity's purchaser holding the bag. *Id.* Even if the Commission tried to use OATi tag data in an attempt to trace transactions back, it would hit a wall for power sourced in PJM and delivered within MISO. *Id.* For instance, witnesses for Quest and WPS ESI estimate that approximately 75 percent of the power Mirant used to satisfy its obligations to WPS ESI was sourced within PJM. This would mean that Mirant's upstream supplier would be unidentifiable 75 percent of the time. *Id.* at 21.

498. Even assuming that "ripple" shift-to-shipper claims are permissible, Mirant emphasizes that WPS ESI has no SECA liability to "ripple" back to its suppliers. *Id.* at 21. Mirant remarks that there is a claim by Quest against Mirant and a claim by WPS ESI against Mirant. The missing link, contends Mirant, is a shift-to-shipper claim by Quest against WPS ESI. *Id.* Mirant proceeds to point out that – even if one existed – a claim by Quest against WPS ESI would not have merit because Quest made no demonstration that it had an existing contract with a supplier that continued into the transition period. *Id.* at 22. Furthermore, Quest made no demonstration that WPS ESI was its "shipper," and Quest also failed to demonstrate what portion of its load was served by WPS ESI. *Id.*

499. If Quest is successful in its Phase 1 arguments and obtains a substantial reduction in its SECA liability, Mirant requests that its own SECA obligation to Quest (if the Presiding Judge determines such an obligation to exist) also be proportionately reduced. *Id.* at 23. Mirant requests a similar SECA liability reduction in the event that Quest is able to recoup SECA from third parties, including its customers. *Id.*

500. Mirant criticizes Quest and WPS ESI for "confus[ing] the issues and obfuscate[ing] the record" by referring to themselves in their Initial Brief as the joint entity: "Quest/ESI." Mirant RB at 2. Insisting that such a reference is improper, Mirant points out that Quest and WPS ESI are separate legal entities with distinct claims against Mirant. *Id.* Most significantly, WPS ESI is not a LSE and should not be referred to as such. *Id.*

501. Mirant emphasizes the undisputed fact that Quest had no contractual obligation to pay Mirant, and that Mirant had no contractual obligation to deliver power to Quest. *Id.* at 5. Accordingly, Quest's reference in its Initial Brief to the "four power contracts with [Mirant] for delivered power" is inaccurate. *Id.*

502. Mirant refutes the contention that Quest was a third-party beneficiary to Mirant's contracts with WPS ESI, arguing instead that the precise terms of the Western Systems Power Pool (WSPP) agreement (which governs Mirant's contracts with WPS ESI) indicate that the contractual parties do not intend to create third-party beneficiaries. *Id.* at 7.

503. Mirant challenges Quest's assertion that Mirant obtained transmission and paid the RTOR for approximately 95 percent of power that crossed the seam that was delivered to Quest. *Id.* at 10. Specifically, Mirant noted that this assertion arose for the first time during the redirect examination of Mr. Zakem by Quest, after which Mirant was denied the opportunity to recross. *Id.* Arguing that its denial of recross raises due process concerns, Mirant requests that the testimony be stricken from the record. *Id.* at 11-12, note 40.

504. Mirant argues that Quest should not be able to recover damages from Mirant under a theory of unjust enrichment. *Id.* at 11. Specifically, Mirant notes that Quest has not cited any precedent to support the recognition of a quasi-contractual relationship between two parties for the sole purpose of awarding equitable damages. *Id.* at 12. Additionally, Mirant argues that Quest's failure to file such a claim in the bankruptcy proceeding resulted in the discharge of the claim. *Id.*

505. Moreover, Mirant asserts that Quest has not met the elements of an unjust enrichment claim. *Id.* at 12. Notably, Quest cannot show that it conferred a benefit upon

Mirant or that it would be inequitable for Mirant to retain any benefit that may have been conferred upon it without payment of its value to Quest. *Id.* at 13.

506. Mirant claims that even if it did benefit from the elimination of the RTORs, Quest should not obtain relief under an unjust enrichment claim because the Commission conferred this benefit – not Quest. *Id.* at 13. Furthermore, Mirant cites legal authority indicating that Quest cannot recover a benefit that Mirant received from a governmental authority.[96]

507. Mirant regards as inaccurate the contention that Quest continued to pay the RTOR after the Commission eliminated the rate. Mirant RB at 17. Mirant remarks that WPS ESI did not have to source its power in a way that would subject it to RTORs. *Id.* Since WPS ESI served as Quest's wholesaler, Mirant proceeds to argue that Quest, similarly, was not obligated to pay the RTOR. *Id.*

508. Mirant also refutes WPS ESI's claim of being subject to a RTOR by virtue of the rate being bundled into its contract price. Mirant IB at 19. Mirant explains that prices are determined based on the future expectations of power marketers, not based on whether a RTOR existed. *Id.* In this respect, Mirant argues that RTORs are not actually embedded in the price. *Id.*

Discussion/Findings/Conclusions

509. On September 6, 2005, Quest/ESI filed a Notice of Intent to File Shift-To-Shipper in Phase II. Ex. S-3 at 28. The claims involve two sets of power supply contracts at a delivery point of "Into MECS": the first set of contracts exists between Mirant and WPS ESI, and the second set exists between WPS ESI and Quest. Ex. QST-21, 22.

510. WPS ESI purchased Quest on January 29, 2003. Quest and ESI have pursued their issues jointly throughout this proceeding. Ex. QST-20 at 13:5-6, Quest IB at 55.

511. It is undisputed that WPS ESI and Quest were parties to a credit agreement dated May 16, 2000 pursuant to which WPS ESI received a sales spread of $0.25 per MWh for power bought from a third-party and sold to Quest. Ex. QST-20 at 10:4-10; MIR-1 at 10:19-11:1.

512. As a relatively small market player, Quest relied on WPS ESI as a "credit sleeve" in order to procure long-term purchases of power, which would otherwise have been unavailable to Quest. Ex. QST-20 at 8:9-9:3. After securing such credit, Quest negotiated a power supply arrangement with Mirant to serve its retail load. Quest

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[96] Mirant RB at 14 (citing *Smith v. Grand Canyon Expeditions Co.*, 84 P3d 1154 (Utah 2003)).

maintains that although this arrangement was not documented through a direct contract with Mirant (based on the aforementioned credit problems), a *de facto* contract existed between the two parties by way of an apparent link between (1) the contract establishing the relationship between WPS ESI and Mirant; and (2) the contract establishing the relationship between WPS ESI and Quest. For the reasons discussed below, Quest is correct in its position that there is a contractual link to tie Mirant to Quest as Quest's shipper and supplier.

513. As shown in the OATi tag data, and by the testimony of Quest's witness Mr. Zakem, the power supplied by Mirant that was specified for delivery to WPS ESI at MECS was ultimately the same power that was specified for delivery to Quest. Tr. 1746; QST-20, 8:2-7. Moreover, Quest correctly points out that WPS ESI did not reserve transmission and did not appear as a valid transmission provider in the physical path of any of the OATi data tags that were reviewed throughout the course of discovery. Tr. 1744-5. Having played no role in the physical delivery of power to Quest, WPS ESI cannot possibly be considered a legitimate supplier or shipper. In contrast, Mirant did assume responsibility for the delivery of power into the Quest sink.

514. The evidence in this case establishes a credit arrangement between Quest and WPS ESI. Ex. QST-23. As a result of this contract, WPS ESI could purchase and sell for Quest. *Id.* at 2 (§9.01(a)). This credit arrangement does not convert WPS ESI into a "shipper" or "supplier" under Paragraph 45 of the Commission's November 17 Order. The contractual formalities in the instant dispute do not change the natural conclusion that Mirant served as both the supplier and shipper to Quest. WPS ESI played only a nominal role in what was ultimately a transaction confined to two parties: Mirant and Quest. WPS ESI nominally appeared for purposes of the agreement in effect since May 2000. Ex. QST-23. This conclusion is particularly salient here given the fact that Quest is a wholly-owned subsidiary of WPS ESI. *See* Ex. QST-20 at 13:5-6. In light of this corporate relationship, the fact that WPS ESI acted as a credit sleeve for Quest and the fact that *de facto* the power was delivered and supplied to Quest, it is deemed appropriate for Quest/ESI to shift to its shipper, Mirant.

515. Mirant's witness testimony implying lack of knowledge of a credit arrangement is not credible. On the other hand, the *de facto* relationship is corroborated by Quest's witness, Mr. Zakem, who stated that Mirant operations and Quest operations communicated directly each business day to schedule delivery of power, to reconcile previous deliveries, and to settle damages if the amounts delivered were more or less than the contract called for. Ex. QST-20 at 11:17-22. Mirant was the source of the power and Quest was the sink for scheduling purposes. Tr. 1746; *see* Ex. QST-20 at 8:2-7. The evidence also shows that Mirant obtained transmission. Tr. 1746, MIR-11.

516. The evidence shows that Quest/ESI paid the contract price charged by Mirant, which was set before the RTORs were eliminated. Ex. QST-20 at 15:7-12. This evidence

demonstrates that the confirmations had a delivery period beginning in 2002 and extending through the transition period, thereby falling within the definition of bundled power contracts. Ex. QST-20 at 6. Quest avers that the contract price included transmission and thus the RTOR. Quest RB at 33. Mirant does not dispute this. Indeed, the scheduling confirmation agreement between Quest and WPS ESI expressly provides that the "[s]eller shall schedule, arrange, and be responsible for transmission service." Ex. QST-22 at 4. Playing only a nominal role in this sleeve transaction, WPS ESI is not the "Seller" to which this clause refers.

517. Given the contractual relationships and links discussed above, the Seller is clearly Mirant. Thus, Mirant was the party responsible for transmission service, including payment of the RTOR, which was reflected in the price of Quest's contract. These facts indicate that Quest was incurring both the SECA and RTOR, which remained embedded in its fixed contract price. As the party that collected the contract price, but does not now pay RTORs, Mirant is the proper party against whom a shift-to-shipper claim may be brought pursuant to Paragraph 45 of the November 17 Order.

518. Mirant requested judicial notice of documents filed in its bankruptcy proceeding. Although late in the game for this request, it is nonetheless granted. Nevertheless, Mirant is unpersuasive in its attempt to use the bankruptcy discharge to shield itself from the shift-to-shipper claim. See Bankruptcy Response. This argument is irrelevant and without merit because Quest was not pursuing a bankruptcy claim against Mirant, but rather a shift-to-shipper claim under Paragraph 45 of the November 17 Order. These are clearly distinguishable claims. Quest correctly avers that the TOs' open-access tariffs are the basis for its claim against Mirant.

519. For the reasons discussed above, the SECA is most appropriately reallocated directly from Quest to Mirant. Due to its limited role as a credit sleeve in the purchasing arrangements between Quest and Mirant, WPS ESI plays no role in this reallocation scheme. Thus, the "ripple" claim brought by WPS ESI against Mirant is essentially an argument in the alternative and need not be addressed, given that this ruling will allow Quest to shift its SECA directly to Mirant.

520. Furthermore, it is concluded that Mr. Zakem's calculation to determine the amount of the SECA to be shifted to Mirant is correct and should be followed. Mr. Zakem uses a demand based allocator including loss factors. Ex. QST-20 at 20:9-21:13. His testimony is entitled to significant weight. In addition, his testimony shows the inconsistencies in Mirant's expert's calculations.

521. If Quest's SECA obligations are reduced through the course of the instant proceedings, its shift-to-shipper claim against Mirant's shall be reduced accordingly. However, Mirant is unpersuasive in the argument that its SECA liability should also be reduced by the amounts that Quest is able to collect from its retail customers. Whether

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Quest can recover from its retail customers is irrelevant, as this is wholly unrelated to the SECA charges at issue in the instant proceeding.

522. Therefore, it is found that Quest/ESI can shift a portion of its SECA charges to Mirant. The specific amount shall be established based on the findings in this decision.

Green Mountain's SECA Obligation:

Issue: Can the Unexecuted Service Agreements for Transmission Service and Market Participant Status filed by the Midwest ISO in docket No, ER05-1423-000 justify the imposition of SECA charges on Green Mountain pursuant to Schedule 22 of the Midwest ISO Tariff?

Parties' Contentions

Green Mountain Energy Company

523. Green Mountain's initial brief argues that Schedule 22 of the Energy Markets Tariff (EMT or Tariff) may not be applied to Green Mountain. It argues that it does not qualify as a Transmission Customer or Market Participant under the Midwest ISO's EMT or the unexecuted service agreements. This is at issue in this proceeding notwithstanding the Order Denying Motion to Amend List of Issues issued on April 26, 2006. Green Mountain IB at 23. In support, Green Mountain cites the Commission's October 31 Order in Docket No. ER05-1423-000. Green Mountain argues that the order incorporates the issue into this proceeding and that it is not an issue pending rehearing. *Id.* at 20-23 (citing October 31 Order, 113 FERC ¶ 61,114 at P17), June 16 Order, 111 FERC ¶ 61,409 (2005) (June 16 Order)). Green Mountain requests reconsideration of the order denying its motion to amend the list of issues. Green Mountain IB at 18.

524. Schedule 22 of the EMT permits the Midwest ISO to file unexecuted service agreements even if the entity has not requested such a filing. *Id.* at 24. However, Green Mountain argues, that the applicability of Schedule 22 is defined by the provisions of the EMT which establish the minimum requirements for an entity to be eligible for Transmission Customer or Market Participant status. *Id.*

525. Green Mountain avers that it does not qualify as a Market Participant since it does not meet the requirements in the Midwest ISO's EMT and unexecuted Attachment W[97]

[97] Attachment W sets forth the conditions an applicant must meet to be eligible for Market Participant status. The EMT defines a Market Participant as an entity that (i) has successfully completed the registration process with the Transmission Provider and is qualified by the Transmission Provider as a Market Participant, (ii) is financially responsible to the Transmission Provider for all of its Market Activities and obligations,

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

which were filed by the MISO. *Id.* In fact, Green Mountain states, the Midwest ISO has admitted that Green Mountain does not satisfy the criteria to be a Market Participant under the EMT. *Id.* at 25 (citing Ex. GME-3 at 3-4).

526. With regard to the transmission service agreements, Green Mountain argues that the Midwest ISO's filing of unexecuted service agreements for non-firm point-to-point, short term firm point-to-point, long term firm point-to-point and network integration transmission service also violate the EMT. *Id.* Green Mountain asserts that this is because it has never received transmission service from the Midwest ISO, it is not currently seeking to receive transmission service from the Midwest ISO and it does not qualify to receive transmission service from the Midwest ISO. *Id.* at 25-26.

527. These facts have been admitted by the Midwest ISO, Green Mountain contends, and are therefore undisputed in the record. *Id.* at 26 (citing Ex. GME-3 at 3-4). The unexecuted transmission service agreements contain representations about Green Mountain that are not true. *Id.* The Midwest ISO, Green Mountain states, has admitted that with regard to each form of transmission service, it has not determined that Green Mountain is a Transmission Customer under the Midwest ISO's EMT. *Id.* (citing Ex. GME-3 at 6-7). In addition, Green Mountain states that the Midwest ISO has admitted that Green Mountain does not have on file a Completed Application for Long-Term Firm, Short-Term Firm or Non-Firm Point-to-Point Transmission Service. *Id.* (citing Ex. GME-4 at 3-5).

528. Finally, Green Mountain argues that the Commission does not have jurisdiction to hold it liable for SECA charges simply because such charges are included in the Midwest ISO's tariff. *Id.* at 27-32. It is well settled that the Commission cannot expand its jurisdiction through the tariff approval process. *Id.* at 31. Although the Commission accepted Schedule 22 for filing, Green Mountain claims, it has not been approved and it had not been found to be just and reasonable and may be "unjust and unreasonable and unduly discriminatory or preferential or otherwise unlawful." *Id.* (citing February 10 Order at P 39 (2005).

529. Green Mountain cites case law for the proposition that "FERC cannot expand its statutory authority to governmental entities/non-public utilities through § 206(b) simply because such entities voluntarily participated in markets approved by FERC that involved FERC jurisdictional wholesale sales of electric energy in interstate commerce." *Id.* at 31-32 (citing *Bonneville Power Admin. v. FERC*, 422 F.3d 908 (9th Cir. 2005)). In addition, Green Mountain notes that the court also stated that "the fact that these entities had entered into agreements obligating them to abide by FERC approved tariffs could not

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and (iii) has demonstrated the capability to participate in its relevant Market Activities. EMT Module A, Section 1.184, Substitute Second Revised Sheet No. 95.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

enable FERC to extend its refund authority to such entities. *Id.* Thus Green Mountain argues, the Commission has no jurisdiction because it is not now, nor has it ever been a Market Participant in the Midwest ISO Energy Markets or a transmission customer of the Midwest ISO. *Id.* at 27-32.

530. Moreover, Green Mountain asserts, it has not voluntarily entered into any agreement obligating it to pay amounts invoiced by the Midwest ISO. *Id.* at 32. Schedule 22 can only be found consistent with the Commission's jurisdiction, Green Mountain claims, if it is interpreted to apply only to transmission customers and entities that meet the eligibility requirements and receive a particular service. *Id.* Green Mountain seeks a ruling that the Midwest ISO's application of Schedule 22 to Green Mountain is unjust and unreasonable because it results in action that is beyond the Commission's jurisdiction. *Id.* at 27. Last, Green Mountain also requests that the rulings admitting DPL Exhibit Nos. 7, 8, 11, 12, 14, 16, 21 and 26 over its objection be reversed. *Id.* at 33. Green Mountain argues that the rulings were erroneous because the exhibits were not authenticated and no foundation was provided. *Id.* at 34.

531. Next, Green Mountain argues that, AEP/Exelon's citation to the Network Operating Agreement between BP Energy and the Midwest ISO is not enough to support its argument that Green Mountain is a third party beneficiary. *Id.* at 11-14. The statement that BP Energy buys wholesale power for Green Mountain's retail customers is not sufficient to establish that "the contracting parties [the Midwest ISO and BP Energy] have clearly expressed their intention that the third parties have right[s] conferred upon them."[98] Green Mountain also asserts that the Commission has rejected AEP/Exelon's theory.[99]

532. Next, Green Mountain argues that Dayton's Pierce-the-Corporate Veil Theory is inconsistent with Commission precedent and the precedent upon which Dayton relies, and is also unsupported by evidence in the record. With regard to Dayton's arguments concerning control, Green Mountain states that courts have refused to pierce the corporate veil even in instances where an entity owned forty-two percent or all of an affiliate. *Id.* 17-20. Moreover, Green Mountain argues, Dayton has failed to provide evidence that refusing to pierce the corporate veil in this case will result in fraud or injustice. *Id.* at 19. Green Mountain also asserts that Dayton has not supplied a

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[98] *Id.* at 13 (citing AEP/Exelon at 53, *Power Auth. Of the State of N.Y. v. Long Island Lighting Co.*, 60 FERC ¶ 61,069 at P 61,236 (1992), *rev'd and remanded sub nom. on other grounds, Long Island Lighting Co. v. FERC*, 20 F.3d 494 (D.C.Cir. 1994), *order on remand*, 68 FERC ¶ 61,116 (1994), *reh'g granted in part*, 71 FERC ¶ 61,126 (1995) (NYPA)).

[99] *Id.* (citing *Power Auth. of the State of N.Y. v. Long Island Lighting Co.*, 60 FERC ¶ 61,069 at 61,237).

supporting witness or citations in the record to substantiate its veil piercing theory or the underlying claims. *Id.* at 20-23.

533. Finally, Green Mountain addresses Dayton's assorted arguments. Dayton's argument that Green Mountain is subject to the Commission's FPA jurisdiction is also unsupported, Green Mountain claims. *Id.* at 24. Green Mountain states that Dayton has not provided evidence that the Midwest ISO provided Green Mountain with transmission service. *Id.* Next, Green Mountain argues that Dayton has not supported its assertion that Green Mountain's investors should be liable for its SECA charges. *Id.* Green Mountain also states that Dayton has not provided evidence that the applications Green Mountain submitted to the Midwest ISO enabled Green Mountain to provide service. *Id.* at 26. In fact, Green Mountain argues that contrary to Dayton's contentions, the record actually shows that whatever transmission service Green Mountain needed to provide service was arranged and provided for by its suppliers BP Energy and CCG. *Id.* Green Mountain also contends that the fact that it withdrew its shift-to-shipper claims, not just against BP Energy, but against CCG and CMS as well, shows that Green Mountain did not give BP Energy preferential treatment as Dayton claims. *Id.* at 27.

Dayton Power and Light Company

534. Dayton is a public utility that is a member of PJM and the Midwest ISO. Dayton I.B. at 1. Dayton is physically located on the PJM/ Midwest ISO border with generation in both regions. *Id.* Dayton states that it has not received the $18 million in SECA obligations that it is owed by Green Mountain. *Id.* at 3-4. Green Mountain, Dayton contends, was identified on the NERC tag data as the LSE that imported power over Dayton's transmission facilities. *Id.* at 4. Dayton asserts that Green Mountain needed electric transmission service in order to serve its retail load under the Northeast Ohio Public Energy Council agreement (NOPEC Agreement) it entered on March 31, 2001 to serve retail customers in Northeast Ohio.[100] Accordingly, to continue providing retail service in the Midwest ISO footprint after October 1, 2003, Green Mountain executed applications for service from the Midwest ISO and an application to become a Market Participant of the Midwest ISO. *Id.* at 6 (citing Ex. GME-4 at 3, Ex. GME-3 at 3). To continue providing retail service in Northeast Ohio Green Mountain submitted an agreement to the Public Utilities Commission of Ohio (PUCO) for recertification as a competitive retail electric supplier (CRES) in which it stated that it would comply with the rules and protocols of "the Ohio jurisdictional utilities, or any Independent System Operator (ISO) or Regional Transmission Organization (RTO). *Id.* (citing Ex. DPL-19 at 10). In addition, Dayton states that Green Mountain, threatened to terminate its service to

[100] Green Mountain entered into a Firm All-Requirements Retail Electric Supply Agreement with counties in Northeast Ohio who were members of the NOPEC. Dayton IB at 5.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

NOPEC and later ceased operations in Ohio as of December 31, 2005. *Id.* (citing Ex. DPL-22). Dayton claims that Green Mountain terminated its retail service to avoid SECA liability as evidenced by its on September 2, 2005 letter to NOPEC. *Id.* at 8.

535. When the Midwest ISO filed Schedule 22 on November 24, 2004 to collect the lost revenues of Dayton and the other PJM TOs the Midwest ISO, at first, determined that BP Energy was liable for Green Mountain's SECA obligations attributable to retail load, Dayton states. *Id.* at 7. Later, Dayton contends, BP Energy disputed the charges and requested that the Midwest ISO bill Green Mountain instead. *Id.* (citing Ex. DPL-22 at 2). Dayton also states that the day after receiving a letter from the Midwest ISO confirming that Green Mountain was liable for the $11.5 million SECA charge (August 25, 2005), Green Mountain withdrew its executed applications for Long-Term and Short-Term Firm Point-to-Point and for Non-Firm Point-to-Point Transmission Service which were previously submitted to the Midwest ISO. *Id.* at 8 (citing Ex. GME-4 at 3-5). On September 1, 2005, Dayton states, the MISO filed unexecuted copies of five agreements on behalf of Green Mountain in Docket No. ER05-1423.[101] Dayton states that the Commission accepted the agreements and they became effective. *Id.* (citing October 31 Order, 113 FERC ¶ 61,114).

536. Dayton avers that Green Mountain has been properly assessed SECA charges by the Midwest ISO because Green Mountain has been identified on the NERC tag data, is an LSE, and is a Customer as defined by the Midwest ISO tariff. *Id.* at 17.

537. Specifically, Dayton contends that Green Mountain is a Customer under the broad definition in Schedule 22 because it is listed, in Attachment B to Schedule 22, as an ATSI sub-zone which is responsible for lost revenue responsibility.[102] Green Mountain qualifies as a LSE under the Midwest ISO Tariff, Dayton argues. *Id.* at 16. Green Mountain is the only LSE to completely ignore and not pay its SECA bills, Dayton contends. *Id.* at 17. Dayton claims that Green Mountain has no valid reason not to pay its obligation because Green Mountain: (1) is subject to the Commission's jurisdiction because it is a public utility with electric tariffs on file with the Commission;[103] (2) has been properly assessed SECA obligations because it was identified on the NERC tag

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[101] *See* Ex. DPL-21. The five unexecuted agreements included: Market Participant Agreement, Non-Firm Point-To-Point Transmission Service Agreement, Short Term Firm Point-To-Point Transmission Service Agreement, Long Term Firm Point-To-Point Transmission Services Agreement, and Network Integration Transmission Service Agreement.

[102] Dayton I.B. at 15 (citing Midwest ISO Tariff, 3rd Rev. Vol. No. 1 at 2d Rev. Sheet No. 1050A, Orig. Sheet No. 1050E.03, Subs. 1st Rev. Sheet No. 1050H, and Orig. Sheet No. 1050M.03).

[103] *Id.* at 17 (citing Ex. DPL-16).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

data, is a LSE, and a Customer under the Midwest ISO Tariff;[104] (3) had the option to shift its SECA obligation to its suppliers;[105] (4) had both a Federal and State regulatory obligation to pay the SECA charges because it represented that it would comply with the rules and protocols of jurisdictional utilities, or any ISO or RTO as applicable; and (5) has the financial ability to pay its obligations.

538. Dayton claims that Green Mountain's arguments that it should not be considered a separate sub-zone in the ATSI zone are not valid because BP Energy was responsible for the NERC Tagging, the Commission required the use of NERC tags and Green Mountain's disagreement with the Commission's order does not justify its refusal to pay. *Id.* at 19. Dayton also notes that Green Mountain has not disputed the accuracy of the NERC tags. *Id.* at 20. Therefore, Dayton concludes, Green Mountain bears responsibility for SECA charges and its refusal to pay is unlawful and unjustified.

539. According to Dayton, Green Mountain and its energy supplier BP Energy are corporate affiliates for several reasons including the fact that BP International Limited, a wholly-owned subsidiary of BP Energy owns 28% of Green Mountain.[106] Dayton also points to the fact that Green Mountain is governed by current and former BP executives. *Id.* Green Mountain also admits that BP Energy was a major supplier of the power Green Mountain sold to retail customers in Northeast Ohio, Dayton claims. *Id.* at 23 (citing Ex. GME-1 at 6:7-8). Dayton also asserts that Green Mountain and the BP corporate family were basically one enterprise because Green Mountain informed the PUCO that BP Energy would manage Green Mountain's electricity purchase requirements and execute purchase and sales agreements to meet Green Mountain's peak energy requirements. *Id.* (citing PTO-111A).

540. Dayton also claims that Green Mountain chose not to shift its SECA obligations to its suppliers by withdrawing all of its shift-to-shipper claims, including the one against BP Energy. *Id.* at 9 (citing Ex. DPL-25, Ex. DPL-26, Ex. DPL-27). Specifically, Dayton claims that BP Energy was both the supplier to Green Mountain and the shipper for the transactions, but still Green Mountain refused to shift the obligation to BP Energy, because as Dayton contends, they are essentially the same entity and to do otherwise would adversely affect BP Energy's profits. *Id.* at 22-25. Dayton also argues that to ensure that it and the other PJM TOs collect their lost revenues, it is necessary to pierce the corporate veil of Green Mountain. *Id.* at 26. In support of its arguments, Dayton cites a body of case law that supports piercing the corporate veil in, among other things, the interests of fairness and equity and to prevent circumventing legislative intent. *Id.*

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[104] *Id.*

[105] *Id.*

[106] *Id.* at 22. Judicial notice has been taken of the fact that BP Energy has a 24.5 ownership interest in Green Mountain.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

541. In its reply brief, Dayton argues that Green Mountain was a *de facto* Market Participant and a *de facto* Transmission Customer as evidenced by "(1) its transactions consummated through its suppliers, (ii) its contractual requirement to become a Market Participant, and (iii) its applications (subsequently withdrawn in an attempt to avoid SECA responsibility) to become a Market Participant and to receive transmission service." Dayton RB at 16. In fact, Dayton asserts, Green Mountain became a *de facto* Market Participant after it submitted unexecuted service applications to the Midwest ISO and was able to continue service in the Midwest ISO foot print on October 1, 2003. *Id.* at 16 (citing Ex. GME-3 at 3; GME-4 at 3-5; Dayton IB at 27-28). Dayton also states that Green Mountain's argument that it has known and measurable changes due to its increased reliance on BP Energy to obtain its supplies does not necessarily impact the amount of through and out service required. *Id.* This is because although Green Mountain claims that most of BP Energy's supplies originated from sources within the Midwest ISO, through and out service may still have been used. *Id.* (citing Tr. at 1634:18-1635:12).

542. Dayton argues that the "additional issues" that Green Mountain raised in its initial brief should be rejected since the Commission did not set those issues for hearing, a ruling was issued stating that the issues would not be briefed, the arguments are a collateral attack on the Commission's orders and rulings made in this proceeding, and the impermissible arguments confuse the issues. *Id.* at 20. In addition, Dayton claims that Green Mountain's arguments are an impermissible attack on the Commission's orders and beyond the scope of this proceeding. *Id.* at 21. Specifically, Dayton points to the order issued on April 27, 2006 which states that those issues are before the Commission and not included in this proceeding. *Id.* (citing February 10 Order, 110 FERC ¶ 61,107 at P 4). Dayton also points to the fact that the Commission accepted the four unexecuted Transmission Agreements and the unexecuted Market Participation Agreement subject to the outcome of this proceeding and the pending request for rehearing. *Id.* at 22 (citing February 10 Order at P 15). In addition, Dayton states that Schedule 22 is a filed rate that has been accepted by the Commission effective December 1, 2004. *Id.* at 23.

543. Green Mountain's objections to exhibits admitted into evidence are without merit, Dayton contends, because four of the exhibits are public documents filed with the Commission and judicial notice can be taken of filings made in Commission proceedings. *Id.* at 24. Second, Dayton states that Green Mountain's arguments concerning the Federal Rules of Evidence (FRE) fail because the FREs do not apply to administrative proceedings and the Federal Power Act (FPA) states that the FRE do not apply to Commission hearings.[107] Next, Dayton states that the Commission promulgated Rules of Practice and Procedures for trial-type hearings in Order No. 225 and specifically did not

[107] *Id.* at 24 (citing Fed. R. Evid. 101; FPA § 308(b), 16 U.S.C. §825g(b)).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

adopt the FREs and the Commission and its Administrative Law Judges have held that the FREs do not apply in Commission hearings.[108] Dayton also contends that Rule 509 states that the standard for the admissibility of evidence, is that "irrelevant, immaterial, or unduly repetitious material" should be excluded.[109] The exhibits were found relevant and admitted into evidence and Green Mountain does not argue that the exhibits are not relevant.[110]

Midwest ISO Transmission Owners

544. The Midwest ISO TOs argue that Green Mountain is the only entity in the Midwest ISO that refused to pay its SECA obligation. MISO TO I.B. at 47. According to the Midwest ISO TO's, Green Mountain is correctly identified as a sub-zone under Schedule 22. *Id.* (citing Ex. MTO-1 at 35-36, MISO TO I.B. at Section III.C). The Midwest ISO TOs also argue that Mr. Linxwiler, Green Mountain's witness, admitted that Green Mountain served retail load during the test period and transition period. *Id.* (citing Tr. at 1613). Finally, the Midwest ISO TOs state that the Commission's acceptance of Schedule 22, the correct identification of Green Mountain as a sub-zone and the Commission's order accepting the assessment of SECA charges to Green Mountain make it clear that Green Mountain is liable for the SECA charges assessed against it. *Id.* at 47-49. In addition, the MISO TOs argue that Green Mountain failed to comply with the Tariff provisions concerning dispute resolution. *Id.* at 48.

545. In their reply brief, the Midwest ISO TOs state that contrary to the assertions of AEP, Exelon and Dayton, Green Mountain's failure to pay its SECA charges must not increase the obligation of the other Midwest ISO TOs. MISO TOs RB at 34. The Midwest TOs request that an order be issued requiring Green Mountain to pay its SECA obligation or in the alternative, state that Green Mountain has no basis to challenge its obligation to pay its SECA charges. *Id.* In addition, the Midwest ISO TOs also argue that Green Mountain has not supported any known and measurable changes. *Id.* at 32. Green Mountain continued to serve load and benefit from the elimination of the RTORs during the transition period. *Id.*

546. Green Mountain's refusal to pay its SECA obligation based on the argument that it is not a Market Participant or Transmission Customer is a collateral attack on the Commission's orders accepting the compliance filings. MISO TOs R.B. at 34. Green Mountain's status as a Transmission Customer or Market Participant is irrelevant to its obligation to pay its SECA charges. *Id.* at 34. They also argue that Green Mountain had

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[108] *Id.* (citation omitted).

[109] *Id.* at 25 (citing 18 C.F.R. § 385.509).

[110] *Id.* (citing Tr. at 1609:22-24).

load for the majority of the transition period and was therefore properly classified as a sub-zone. *Id.*

547. The provisions of the Midwest ISO's Tariff, as accepted by the Commission, recognize that some entities responsible for SECA charges may not be Transmission Customers or Market Participants. *Id.* Specifically, the Midwest ISO TOs point to Schedule 22 which provides that the term "Customers" includes entities that "may not be Transmission Customers but which will bear responsibility for some SECA" and also allows the Midwest ISO to submit unexecuted service agreements whether the entities request submission or not." *Id.* at 35 (citing Ex. MTO-189 at 2). Therefore, the Midwest ISO TOs assert, it does not matter whether Green Mountain is a Transmission Customer or Market Participant. *Id.*

548. If Green Mountain disagrees with the Commission's rulings, the Midwest ISO TOs assert, Green Mountain can request rehearing and judicial review, but relief cannot be granted in this initial decision. *Id.* The Midwest ISO TOs also contend that the Commission provided a way for Green Mountain to mitigate its SECA liability, but Green Mountain withdrew its notice to shift its obligation to BP Energy Company. *Id.* at 36 (citing Ex. DPL-24 (Notice of Intent), Ex. DPL-25, Ex. DPL-26, Ex. DPL-27). In addition, the Midwest ISO TOs assert that Green Mountain has major investors and is financially able to pay. *Id.* The other Midwest ISO TOs should not be responsible for Green Mountain's unpaid SECA obligations and the Midwest ISO TOs request that such a proposal be rejected. *Id.* at 38.

<u>The Midwest Independent Transmission System Operator, Inc.</u>

549. The Midwest ISO's initial brief states that it lawfully assessed Green Mountain's SECA charges based on Schedule 22. MISO I.B. at 3. In addition, the Midwest ISO contends that Schedule 22 requires it to collect SECAs from Green Mountain from December 1, 2004 through March 2006 on a monthly basis and those charges are set forth in Attachment B of Schedule 22. *Id* (citing Ex. MTO-189). The Green Mountain sub-zone was established consistent with the Commission's methodology as explained by Dr. Heintz. *Id.* (citing Ex. MTO-1 at 29:18-44:15). The Midwest ISO states that Schedule 22 provides that it will bill its "Customers" which includes "Transmission Customers a*s well as other entities in a zone that may not be Transmission Customers* but which will bear responsibility for some SECA charges." *Id.* (citing Ex. MTO-189). To the extent that entities have not executed service agreements, Schedule 22 directs it to file "unexecuted agreements whether the entities request submission or not." *Id.* The Midwest ISO states that Green Mountain is a Customer under Schedule 22 regardless of whether Green Mountain has completed a Market Participant Application or other application for transmission service. *Id.* at 4. This is because, the Midwest ISO asserts, Schedule 22 directs it to submit unexecuted service agreements even if the entity does not request such a submission. *Id.*

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

550. The Midwest ISO states that it filed unexecuted service agreements pursuant to Schedule 22 on September 1, 2005 to invoice Green Mountain for SECA charges. *Id.* In addition, the Midwest ISO claims that the Tariff also provides that charges may be collected from entities, such as Green Mountain, that do not take transmission service directly from the Midwest ISO. *Id.* The Midwest ISO states that the Commission accepted its unexecuted agreements subject to refund and the outcome of these proceedings. *Id.* at 5 (citing the October 31 Order, 113 FERC ¶ 61, 114 at P15). The Commission's October 31 Order also found the Midwest ISO's unexecuted agreements with Green Mountain in compliance with Schedule 22, as accepted by the Commission's November 18 Order, the Midwest ISO claims. *Id.* The Midwest ISO also contends that the Commission denied Green Mountain's protest. *Id.* Thus, the Midwest ISO concludes, Green Mountain has no legal basis for challenging the Midwest ISO's SECA assessment against it because the Commission approved Schedule 22 (which includes the Attachment B sub-zones) in the November 28 Order and that the unexecuted service agreements in the October 31 Order. *Id.* at 6.

American Electric Power Service Corporation and Exelon Corporation

551. AEP/Exelon argue that the Commission must determine who is responsible for paying Green Mountain's SECA obligations and direct the MISO to collect such payments with interest from the appropriate parties. AEP/Exelon I.B. at 49-50. The Commission should also consider requiring the Midwest ISO TOs to provide a backstop for the SECA payments owed to AEP/Exelon from the approximately $26 million in excess ET revenues collected by the Midwest ISO TOs. *Id.* at 50.

552. AEP/Exelon also highlighted other facts and events it deems important. *Id.* at 49-56. Particularly, AEP/Exelon state that Green Mountain appears to be the only retail electric supplier serving load in the FirstEnergy service territories in Northern Ohio that did not execute network agreements with the Midwest ISO after ATSI's integration into the Midwest ISO on October 1, 2003.[111] AEP/Exelon claim when ATSI migrated into the Midwest ISO on October 1, 2003, the Commission understood "'that customers will retain the service and rights the[y] currently have under the ATSI OATT,' including reimbursement by FirstEnergy to the competitive retail suppliers for unbundled transmission and ancillary service charges under the MISO OATT."[112] First Energy notified the Commission that the service agreements under the MISO OATT became effective for the affected TOs, including Green Mountain, and that although Green Mountain does not have a service agreement under the Midwest ISO OATT, BP Energy

[111] AEP/Exelon I.B. at 53 (citing *FirstEnergy Service Corp.*, 105 FERC ¶ 61,113 (2003).

[112] *Id.* at 53-54 (citing *FirstEnergy Service Corp.*, 105 FERC ¶ 61,113 at P 12-15).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

and CCG have been making transmission service reservations on behalf of Green Mountain.[113] BP Energy entered a network service agreement with MISO on behalf of Green Mountain and, in addition, the Midwest ISO network operating agreement that was executed by BP states that BP Energy takes network service on behalf of Green Mountain, AEP/Exelon claim.[114] In addition, AEP/Exelon contend that Mr. Linxwiler stated that BP Energy was Green Mountain's only energy supplier. *Id.* at 55 (citing Tr. at 1618:23-1620:13).

553. AEP/Exelon assert that BP Energy also had an agreement with Green Mountain to supply Green Mountain's Northern Ohio energy services customers. *Id.* at 55. AEP/Exelon aver that if BP Energy were named the party responsible for Green Mountain's SECA obligation it could pass those costs on to Green Mountain under the terms of the supply agreement. *Id.* at 56. Green Mountain or BP Energy is liable for the SECA charges, AEP/Exelon claim. Green Mountain is a LSE under the Midwest ISO Tariff and it could be found that BP Energy also meets the definition of a LSE. Green Mountain can be found a third party beneficiary of the contract even though it does not have a direct contract with the Midwest ISO. *Id.* at 57.

FirstEnergy Service Company and FirstEnergy Solutions Corp.

554. FirstEnergy argues that the Commission accepted the unexecuted service agreements for filing and Green Mountain's protest of those filings is currently before the Commission. *Id.* at 34. Thus, AEP/Exelon's and Dayton's request for socialization of the Green Mountain SECA should be denied. *Id.* FirstEnergy also contends that if the Commission denies Green Mountain's request for rehearing, AEP/Exelon and Dayton can seek to enforce the unexecuted agreements in a court of law. *Id.*

Quest Energy, L.L.C, WPS Energy Services, Inc. and Strategic Energy, L.L.C

555. Quest/ESI's and Strategic's reply brief argues that it would be unjust, unreasonable and inconsistent with cost causation principles to make other LSEs in the zone responsible for the amounts that Green Mountain owes TOs as proposed by AEP. Quest R.B. at 24-25 (citing AEP/Exelon I.B. at 10). First, Quest/ESI and Strategic assert that AEP's suggestion that the Green Mountain sub-zone be eliminated should be rejected because the Commission required the allocation of the SECA based on sub-zones unless all the sub-zones agree. *Id.* at 25. Quest/ESI and Strategic states that they do not agree to do so. *Id.* Second, Quest/ESI and Strategic argue that cost causation principles require each LSE to pay its respective SECA allocation. *Id.* at 26. Third, Quest/ESI and Strategic claim that AEP is not entitled to collect every dollar of its lost revenues from

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[113] *Id.* at 54 -55 (citation omitted).

[114] *Id.* at 55 (citing Tr. at 1620:16-21; Ex. PTO-115 at 41-47; PTO-116 at 4).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

2002 and 2003 and any guarantee of recovery would constitute retroactive ratemaking. *Id.* Finally, Quest/ESI and Strategic aver that the TOs have other legal and regulatory avenues to collect the amounts due from Green Mountain. *Id.* at 24, 27.

BP Energy Company

556. First BP Energy asserts that AEP/Exelon's and Dayton's briefs raise new issues that are not within the scope of this proceeding. BP RB at 6. These new claims, BP Energy claims are barred by Rule 216(b) because Green Mountain withdrew its shift-to-shipper claim and neither Dayton nor AEP/Exelon filed an objection.[115] BP Energy also contends that Dayton's and AEP/Exelon's arguments are a collateral attack on the outcome of the Midwest ISO's ADR process in which the Midwest ISO agreed that it had billed BP Energy in error and sought to bill Green Mountain. *Id.* at 9. In addition, BP Energy states the Commission, in adopting its final rule on dispute resolution, stated that "the Commission will give substantial deference to whatever consensus participants reach through the ADR process" provided that the decisions are not contrary to the public interest or inconsistent with statutory requirements.[116] Dayton's and AEP/Exelon's claims are procedurally barred pursuant to the March 20, 2006 Order issued in this proceeding because they did not provide notice of their claims until their initial briefs (which is after the March 27, 2006 deadline established in the order). *Id.* at 10-11. BP Energy claims that Dayton and AEP/Exelon have denied BP Energy and BP International the ability to pursue ripple claims against their own suppliers, file testimony and conduct discovery. *Id.* at 11.

557. Next, BP Energy contends that Dayton's shift-to-shipper arguments should be disregarded and AEP/Exelon's argument asserting that BP Energy is a LSE is mistaken. *Id.* at 12. Dayton's claim that Green Mountain could have shifted its SECA liability to BP Energy is incorrect because BP Energy's contract with Green Mountain was not a bundled contract for delivered power that included continuing compensation for RTORs as required by the Commission's November 17 Order. *Id.* at 12-13. In addition, BP Energy contends, it did not benefit from the elimination of RTORs because the costs associated with the contract were passed through to, and became the responsibility of Green Mountain. *Id.* at 14. AEP/Exelon's argument that BP Energy is liable as a LSE is incorrect. *Id.* According to BP Energy, it is not a LSE in Ohio under Section 1.71 of the Midwest ISO Tariff because the contract under which it supplied Green Mountain's energy and capacity requirements was a wholesale contract and not a contract for retail sales as required by that section. *Id.* BP Energy also claims that Schedule 22,

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[115] *Id.* at 8 (citing 18 C.F.R. § 385.216(b) (2006)).

[116] *Id.* at 9 (citing Alternative Dispute Resolution, Order No. 578, 60 Fed. Reg. 19494 (1995), 1991-96 FERC Stats & Regs., Regulations Preambles ¶ 31,018 at 31,326 (1995)).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Attachment B exempts it from SECA charges because Green Mountain is specifically identified as a sub-zone and the only filed rate for the collection of Schedule 22, Attachment B sub-zone charges identifies Green Mountain as the responsible party. *Id.* at 15-16.

558. BP Energy rejects the arguments that the BP Energy corporate family should be held liable for Green Mountain's SECA liability. BP Energy cites Commission precedent which states that "the decision to pierce the corporate veil is made cautiously and not based on a single factor.… Instead, it must rest on many such factors, *and* the situation must present an element of injustice or fundamental unfairness.[117] First, BP Energy claims that Dayton has failed to provide record evidence that BP Energy or BP International operated and controlled Green Mountain (or was its "alter ego"). Dayton's arguments are without merit, BP Energy argues, because four-fifths of Green Mountain's Board, is appointed by entities other than BP Energy or BP International and over 77 percent of Green Mountain's equity is held by non-affiliated entities as well.[118] Second, BP Energy contends that Schedule 22 names Green Mountain as the party responsible for the SECA charges and Green Mountains relationship with the BP entities has no relevance. *Id.* at 19. In addition, BP Energy notes that Green Mountain did not show BP Energy preferential treatment because it also withdrew its shift-to-shipper claim against CMS and Constellation. *Id.* (citing Ex. DPL-25, Ex. DPL-26).

Discussion/Findings

Is this issue included in this proceeding?

559. As a threshold matter, it is necessary to revisit the ruling in the Order Denying the Motion to Amend. The order found that good cause had not been established for granting the motion on the ground that Green Mountain's proposed issue is before the Commission in a request for rehearing of the June 16 Order. However, upon further consideration and examination of the October 31 Order, it is found that the Commission's October 31 Order did, indeed, place the issue within the scope of this proceeding. *See* October 31 Order, 113 FERC ¶ 61,114 at P 17. The Commission stated that the proper proceeding in which to address this issue, *in addition* to the pending rehearing proceedings of the June 16 Order, is "in the ongoing hearings on the SECA compliance filings, in which Green Mountain is an active participant." *Id.* Further, the Commission

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[117] *Id.* at 16 (citing *William Valentine and Sons, Inc.*, 46 FERC ¶ 61,252 at 61,750 (1989) (emphasis in original).

[118] *Id.* at 18 (citing Ex. B, Netemeyer Affadavit at P 10). BP Energy also states that Green Mountain's president has not been employed by a BP company for over four years and other officers and directors of Green Mountain were formerly employed by AEP and other members of the electric industry.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

also stated that it would "accept the unexecuted service agreements filed by the Midwest ISO, subject to the eventual outcome of the proceedings in Docket No. ER05-6-001, *et.al*."[119] This undeniably places the issue within the scope of this hearing. Therefore, Green Mountain is correct, the issue has been incorporated in the hearing and will be addressed in this decision.

560. Another preliminary matter that must be addressed is BP Energy's request that official notice be taken of its Revised Supplemental Informational Filing.[120] BP Energy states that the Revised Supplemental Filing clarifies that 24.5 percentage interest more accurately represents BP Energy's minority ownership interest in Green Mountain than the 22.6 percent previously argued by BP Energy and the 28 percent alleged by Dayton. A Revised Supplemental Informational Filing has been filed with the Commission along with a supplemental affidavit which attests to the validity of this information. Good cause has been established for granting BP Energy's Motion. Accordingly, BP Energy's motion is granted and official notice is taken pursuant to 18 C.F.R. § 385.508(d) (2006).

Do the unexecuted service agreements violate the TEMT and therefore cannot provide a legal basis for charging Green Mountain a SECA?

561. Green Mountain is a privately held company owned partly by BP International Limited which is a wholly-owned subsidiary of BP PIC (the parent company of BP Energy).[121] As discussed in the immediately proceeding section, it has been officially noticed that BP Energy owns a 24.5 percent interest in Green Mountain. On March 13, 2001, Green Mountain entered into a Firm All-Requirements Retail Electric Supply Agreement with members of NOPEC. Ex. PTO-112B. As a result, Green Mountain entered into contracts to obtain power for its Ohio load. On May 11, 2001, BP Energy, Green Mountain and CMS Marketing Services and Trading Company (CMS) entered into a Power Purchase and Retail Load Serving Agreement. Ex. PTO-111B. By virtue of this agreement, CMS became the seller of power to BP Energy for the benefit of Green Mountain. In addition, Green Mountain and BP Energy entered into an Energy Services Agreement. Ex. PTO-110A (Second Amended and Restated Energy Services Agreement). This agreement provides that within two (2) business days after BP Energy receives the necessary information from the ISO and/or Utilities, in each month, BP Energy shall invoice Green Mountain for the cost of energy for transactions made on

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[119] These agreements include four unexecuted transmission service agreements and one unexecuted market participant agreement. The agreements were filed by the Midwest ISO to invoice Green Mountain for SECA charges. See October 31 Order at P 1.

[120] This supersedes BP Energy's request for official notice contained in Attachment B to its errata to its reply brief filed on July 24, 2006.

[121] Dayton IB at 4 (citing DPL-6, DPL-7 at 12, 14).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

behalf of Green Mountain at the Energy Delivery Points for sale to Green Mountain's retail customers. *Id.* at 32 (§10.1). The cost of energy includes the cost of Capacity, Transmission, Ancillary Services, Brokerage Fees and other direct costs incurred in delivering such Energy to such Energy Delivery Points, including, but not limited to, all costs incurred with complying with any Utility, ISO or other regulatory requirements attributable to the delivery of Energy to the Delivery Points. Ex. PTO-111A at 32 (Section 10.1(a)). In June and July of 2005, the Midwest ISO billed BP Energy for SECA charges under the Midwest ISO TEMT. BP Energy RB at 2. When the Midwest ISO later determined that Green Mountain, and not BP Energy, was the party responsible for the charges it sought to bill Green Mountain instead. *Id.* Green Mountain's multiple arguments concerning its assessed SECA charges will be addressed seriatim.

562. Green Mountain's arguments are unpersuasive. The Commission directed that SECAs be assessed on LSEs. November 17 Order, 105 FERC ¶ 61,212 at P 45. Green Mountain, as a Retail Generation Provider engaged in the retail sale of electric generation is a LSE.[122] First, the Midwest ISO TEMT defines a LSE as "[a]ny entity that has undertaken an obligation to provide electric energy for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System." Second, the FPA defines a LSE as a distribution utility or an electric utility that has a service obligation.[123] A distribution utility is "an electric utility that has a service obligation to end-users or to a State utility or electric cooperative that, directly or indirectly, through one or more additional State utilities or electric cooperatives, provides electric service to end-users." 16 U.S.C. § 824q (a)(1). Under the NOPEC Agreement, Green Mountain provided all of the electrical energy, capacity, reserves, transmission and ancillary service for firm power supply to retail customers. Ex. PTO-112B at 2 (§1.12). Since Green Mountain sold power at retail to customers in Northeast Ohio, it qualifies as a LSE. Accordingly, Green Mountain was properly assessed SECA obligations.

563. Schedule 22 of the TEMT directs the Midwest ISO to bill Customers within its pricing zones and designated sub-zones for SECA charges.[124] It is found that Green Mountain is a Customer under Schedule 22 and has properly been identified as the party responsible for SECA charges under Schedule 22 of the TEMT. The definition of Customers in the TEMT is broad and thus encompasses not only Transmission Customers

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[122] *See* Ex. DPL-17, DPL-18, DPL-19; Ex. PTO-111B.

[123] 16 U.S.C. § 824q (a)(2) (2006). A service obligation means a requirement applicable to, or the exercise of authority granted to, an electric utility under Federal, State, or local law or under long-term contracts to provide electric service to end-users or to a distribution utility. 16 U.S.C. § 824q(a)(3).

[124] Exh. No. MTO-189 at 1 (Tariff at Second Revised Sheet No. 1040 and Tariff at First Revised Sheet No. 1041).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

but also "other entities in a zone… which will bear responsibility for some SECA charges."[125] Green Mountain is such an entity. Although Green Mountain fervently argues that is not a Transmission Customer under the TEMT, the record supports the conclusion that notwithstanding the fact that it did not directly contract with the Midwest ISO,[126] the ultimate responsibility for transmission charges and thus SECAs lies with Green Mountain. Pursuant to the Energy Services Agreement between BP Energy and Green Mountain executed on October 15, 2004, "BPE Energy is (and has been) responsible for arranging, purchasing, and paying for, network transmission service necessary for delivering all of the power from both suppliers directly to Green Mountain's customers in Ohio."[127] BP Energy executed contracts on behalf of Green Mountain to arrange for network transmission service. Under these contractual arrangements BP Energy passed through all energy transmission costs and other direct costs incurred by BP Energy related to the sale of power to Green Mountain.[128] Since the procurement of network transmission service was for the benefit of Green Mountain and its financial responsibility, Green Mountain is the entity that paid transmission costs and should pay SECAs. Thus, Green Mountain is a Customer under the Midwest ISO TEMT and the Midwest ISO's filing of unexecuted service agreements on Green Mountain's behalf was proper.[129] Accordingly, Green Mountain's assertion that the terms of the TEMT somehow render Schedule 22 inapplicable to it are incorrect and do not form an adequate basis for it to escape SECA liability.

564. In addition to providing for the collection of SECAs from Customers, which may be other entities "which will bear responsibility for some SECA charges," Schedule 22 also empowers the Midwest ISO to collect such charges from Customers within "designated sub-zones." Ex. MTO-189 at 1. Schedule 22 provides that "[t]he sub-zones shall be Customers responsible for sinks for which there is OATi data showing lost

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[125] *Id.* at 2.

[126] *See* Green Mountain RB at 12 (citing AEP/Exelon I.B. at 57).

[127] Ex. GME-1 at 5:12-15, Ex. PTO-110A. Mr. Linxwiler also states that "[p]rior to MISO's "Day II" market operations, both BPE and CMS/Constellation were responsible for acquiring and paying for such network transmission service for the respective portions of their supplies to Green Mountain's loads. Both BPE and Constellation must arrange, purchase, and pay for any additional point-to-point transmission service necessary to deliver power for Green Mountain to the ATSI boundary (after which the BPE-purchased network service is used to deliver the power to Green Mountain's customers)." Ex. GME-1 at 5:15-20.

[128] Ex. PTO-110A at 32 (§10.1); BP RB at 13.

[129] MTO-189 at 2. ("To the extent that the other entities have not executed service agreements, the Midwest ISO shall file unexecuted service agreements whether the entities request their submission or not.").

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

revenue responsibility." *Id.* at 2-3. Green Mountain has been properly identified as a sub-zone in the ATSI zone based on NERC OATi E-tag data sink codes.[130] Thus, Green Mountain has also been properly assessed SECA charges as a "Customer" within a "designated sub-zone" under Schedule 22.[131] Accordingly, it is found that the Midwest ISO has properly assessed Green Mountain, which is a Customer as defined in Schedule 22, SECA charges under that schedule and in accordance with the Midwest ISO TEMT.

565. This finding disposes of many of the parties' arguments. First, the Midwest ISO's admission that Green Mountain is not a Transmission Customer is moot since the Schedule 22 definition of Customers allows the Midwest ISO to bill either a Transmission Customer or other entities, such as Green Mountain, in a zone which will bear some responsibility for some SECA charges. *See* Ex. MTO-189 at 2, Ex. GME-3 at 6. In addition, the Midwest ISO is correct in stating that it is irrelevant whether Green Mountain has completed a Market Participant Application or has been deemed such by the Midwest ISO. Midwest ISO I.B. at 4. Schedule 22 does not require an entity to be a Market Participant to be assessed SECA charges. *See* Ex. MTO-189.

566. Green Mountain is the party from whom payment is due. AEP/Exelon and Dayton have posed various arguments asserting that BP Energy and/or BP International are somehow responsible for paying Green Mountain's SECA obligation. Dayton argues that Green Mountain and what it refers to as the "BP Corporate Family' are corporate affiliates and basically one and the same entity such that the circumstances warrant piercing the corporate veil. Dayton I.B. at 23. Dayton has based this argument on, among other things, the fact that BP Energy has a 24.5 percent ownership interest in Green Mountain, Green Mountain is governed by former and current BP executives, and BP Energy was a major supplier of the power Green Mountain sold in Northeast Ohio.[132]

567. The Commission has stated that:

> "[g]enerally speaking, the decision to pierce the corporate veil is made cautiously and is not based on a single factor, whether undercapitalization, disregard of corporate formalities, or sole ownership. Instead, it must rest on many such factors, *and* the situation must present an element of injustice or fundamental unfairness."[133]

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[130] *See* Ex. MTO-1 at 34:17:36:4; *see also* Ex. MTO-189 at 2-3.

[131] *See* Ex. MTO-189 at 1-3.

[132] Dayton IB at 22-23.

[133] *William Valentine and Sons, Inc.*, 46 FERC ¶ 61,252 at 61,750 (1989) (citing *Dewitt Truck Brokers v. W. Ray Fleming Fruit Co.*, 540 F.2d 681, 687 (4th Cir. 1976)).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

The courts look to numerous factors when making such a determination.[134] In light of the Commission's reluctance to pierce the corporate veil, the fact that BP Energy owns a 24.5 percent minority interest in Green Mountain and is governed by former and current BP Energy executives is simply not persuasive enough to support a finding that BP Energy is the alter ego of Green Mountain.

568. Green Mountain has been properly assessed SECA obligations. The Commission ordered LSEs to pay SECAs. Based on the findings in this Initial Decision, Green Mountain's SECA obligation may change. Therefore, it is ordered to pay its SECA obligations once such amounts are determined.

569. Green Mountain's assertion that the Commission lacks the necessary jurisdiction to allow the Midwest ISO to assess it a SECA under Schedule 22 is also rendered moot by the finding above. As discussed above, Green Mountain is a LSE. Again, Green Mountain's argument that Schedule 22 does not apply to it because it is not a Transmission Customer or Market Participant is irrelevant. Green Mountain is a Customer under the Schedule 22. Dayton's arguments concerning Green Mountain's liability have also been addressed above. Based on these findings, Dayton's and AEP/Exelon's arguments concerning Green Mountain's liability are rendered moot.

Were certain evidentiary rulings arbitrary and capricious?

570. Dayton's Exhibit Nos. DPL-6 through DPL-31 were found relevant and admitted into evidence on May 10, 2006 pursuant to Rule 509, 18 C.F.R. § 385.509 (2006). Tr. at 1609:22-1610:3. Reconsideration is denied. As a result, the appropriate venue for Green Mountain to raise its objection to this ruling is in its brief on exceptions. *See* 18 C.F.R. §§ 385.509 (b)(3), 385.711 (2006). In addition, the Commission grants presiding judges "broad discretion" to decide certain procedural matters "and will not be overturned unless their discretion has been abused or the complaining party can show that it has been unduly prejudiced." *Arizona Public Service Co.*, 23 FERC ¶ 61,419 at 61,934 (1983). In this case, Green Mountain has not been prejudiced by the ruling.

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[134] "Again, courts have pinpointed numerous factors to consider in assessing whether a subsidiary is the alter ego of its parent. For example, factors supporting disregard of the subsidiary's veil include common stock ownership, directors or officers, or business departments, between parent and subsidiary; the parent's financing or incorporating of the subsidiary; the parent's payment of salaries and expenses, and its use of the property of the subsidiary; and the intermingling of the daily operations of the two corporations. *Valentine and Sons, Inc.*, 46 FERC ¶ 61,252 at 61,749 (citing *United States v. Jon-T Chemicals, Inc.*, 768 F.2d 686, 691-92 (5th Cir. 1985), *cert. denied*, 475 U.S. 1014 (1986)*; Steven v. Roscoe Turner Aeronautical Corp.*, 324 F.2d 157, 161 (7th Cir. 1963).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

IV. RULINGS ON PARTIAL SUMMARY DISPOSITIONS

A. CMS ERM

Issue: Should CMS ERM's Motion for Summary Disposition be granted?

Introduction

571. On March 9, 2006, CMS ERM filed a motion for summary disposition (CMS ERM Motion).[135] The motion was denied, without prejudice, after oral argument held on March 31, 2006. Tr. at 565:13-599:17. CMS renewed its motion for summary disposition on May 5, 2006. *Id.* at 1273:17-1277:1. The motion was granted on the ground that CMS ERM did not take service at the MECS.DECO.CMSZ sink during the transition period and "SECA charges should not have been imposed." *Id.* at 1369:12-21. It was also stated that a decision would be issued on this ruling as part of the Initial Decision. *Id.* at 1369:23-1370:1.

Parties' Contentions

CMS ERM

572. In its filed motion, CMS ERM first argues that the SECA obligation should not be assessed on CMS ERM at the MECS.DECO.CMSZ sink because it served no retail load during the transition period. CMS ERM claims that it has not served any retail load at the MECS.DECO.CMSZ sink nor moved any electricity through and out of the PJM system to serve retail load at that sink since September 2003. CMS ERM Motion at 5 (citing Exh. CMS-1 at 6:1-4). Although it is undisputed that it served no load, CMS ERM contends, the MISO has still assessed it a SECA of approximately $57,000 for the period December 1, 2004 and March 31, 2005 and $88,228 per month for the period April 1, 2005 and March 31, 2006. *Id.* CMS ERM states that these charges are based on the retail load it served at the MECS.DECO.CMSZ sink in 2002 and 2003. *Id.*

573. Second, CMS ERM argues that the charge violates the filed rate doctrine because the MISO seeks to assess a charge for service that did not exist, was not approved and was not on file when the service was rendered. The SECA charge, CMS ERM contends, is also inconsistent with the Commission's order on rehearing that affirmed an initial decision which found that SECA charges would not violate the filed rate doctrine only

[135] The Midwest ISO Transmission Owners and the Indicated Transmission Owners filed answers arguing that the motion should be denied.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

because it would be based on current usage.[136] Last, CMS ERM claims that the SECA charge is inconsistent with the Commission's cost causation principles because it did not serve any retail load at the MECS.DECS.CMSZ sink. Therefore, it contends, there can be no lost RTOR revenues associated with and accordingly, no benefit derived from, the elimination of the RTORs associated with that sink. *Id.*

574. In its reply brief, CMS ERM argues that the ruling granting CMS's motion for summary disposition should not be reversed. CMS RB at 8. CMS ERM claims that AEP/Exelon's request for rehearing of the ruling granting CMS ERM's motion for summary disposition is procedurally barred and, instead is required to be submitted as a brief on exceptions. *Id.* at 5, 8-9. Second, CMS ERM argues that contrary to AEP/Exelon's assertions, the Commission has not rejected the claim that the SECAs violate the filed rate, retroactive ratemaking and cost causation doctrines because the SECAs addressed in the Commission's November 17 Order differ from those in the MISO SECA filings submitted in late 2004 and early 2005. *Id.* at 10-11. Specifically, CMS ERM claims that the SECAs addressed in the November 17 Order are based on future transactions and here the payments are based on transactions completed in 2002 and 2003. *Id.* Next, CMS ERM contends that assessing a SECA to the MECS.CONS.CMSZ sink violates the filed rate doctrine and the rule against retroactive ratemaking because it is assessing a charge for past service that did not exist, was not approved and was not on file at the time the service was rendered.[137] In addition, CMS argues that assessing a SECA at that sink violates cost causation principles. *Id.* at 13. CMS ERM also argues that the Commission's acceptance of the MISO SECA filings, subject to hearing and refund does not mean that the Commission already found the compliance filings just and reasonable as AEP/Exelon implies. *Id.* at 6. Accordingly, CMS ERM requests that AEP/Exelon's request for reversal of the ruling granting it summary disposition be rejected. *Id.* at 7.

Midwest ISO Transmission Owners

575. At hearing, the Midwest ISO TOs also stated that the Commission should decide the issue. In their initial brief, the Midwest ISO TOs argue that following the Presiding Judge's rationale in granting both CMS ERM's and Green Mountain's motions for summary disposition, if SECA charges for the CMS ERM sub-zone and the Green Mountain sub-zone (for the last three months) are to be recovered, such charges should be recovered from the entity that served the load. Midwest TOs IB at 46 (citing Ex. PTO-117). The Midwest ISO TOs' reply brief forwards a similar argument. Midwest

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[136] CMS ERM Motion at 7 (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 102 FERC ¶ 63,049 at P 90 (2003)).

[137] CMS RB at 11-12 (citing *Pacific Gas & Electric Co. v. FERC*, 373 F.3d 1315, 1320 (D.C. Cir. 2004).

ISO TOs RB at 32-33.

American Electric Power Service Corporation and Exelon Corporation

576. At the hearing, AEP and Exelon opposed the motion arguing that the issue of retroactive ratemaking is not encompassed in this proceeding, but should instead be addressed by the Commission. Tr. at 1277:18-24. AEP/Exelon also argued that the ruling required some deliberation and not be should ruled on at that time. *Id.* at 1274:4-7. AEP/Exelon's initial brief argues that the ruling granting the motion for summary disposition raised by CMS ERM should be reversed. AEP/Exelon IB at 41. AEP/Exelon claim that CMS ERM does not dispute the lost revenue calculations underlying the $1.2 million in SECA charges for the MECS.DECO.CMSZ sink, but CMS does, however, dispute the allocation of such charges to CMS ERM. *Id.* at 40. Thus, AEP/Exelon request a finding that that $1.2 million in SECA charges originally assessed to CMS ERM by the compliance filings for that sink were properly calculated. *Id.* at 41.

577. AEP/Exelon further argue that by granting CMS ERM's motion and relieving it of its SECA obligation for the last three months of the transition period, the ruling "threatens to undermine the principle of revenue neutrality that led the Commission to adopt the transitional SECA charge in the first place." *Id.* at 42. In addition, they argue that by not specifying an alternative means of collecting the SECA charges assigned to CMS ERM, "the ruling threatens to impose rather than alleviate costs shifts on transmission owner's native load customers." *Id.*

578. Second, AEP/Exelon argue that contrary to CMS ERM's assertions, the SECA filings do not violate the filed rate doctrine, the principles of cost causation and do not constitute retroactive ratemaking. *Id.* In support of these contentions, AEP/Exelon state that the Commission directed the transmission owners to use 2002 and 2003 data to develop SECAs and in the Order on Rehearing, the Commission rejected those arguments. *Id.* at 42-44. They also argue that CMS ERM, by moving for summary disposition solely on the ground that the SECAs violate the rule against retroactive ratemaking, is challenging the Commission's findings. *Id.* at 43. AEP/Exelon also argue that CMS ERM's motion is improper because the issues it raises in support were not set for hearing by the Commission. *Id.* at 44. To summarize their arguments, AEP/Exelon state that the filed rate doctrine and its related principles regarding retroactive ratemaking and cost causation do not provide a basis to grant CMS ERM's motion for summary disposition and that it was an error to grant CMS ERM's summary disposition on those grounds. *Id.* at 45. AEP/Exelon also argue that CMS ERM has failed to establish that AEP/Exelon did not comply with the Commission's orders. *Id.* at 44. Accordingly, AEP/Exelon request reversal of the ruling granting CMS ERM's motion for summary disposition. *Id.* at 41-46.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Baltimore Gas and Electric Company

579. BGE's reply brief states that the ruling granting CMS ERM's motion for summary disposition was correctly decided and should not be reversed as requested by AEP/Exelon. BGE RB at 21. BGE also argues that the ruling should be expanded to find that the SECA constitutes retroactive ratemaking and violates the filed rate doctrine. *Id.* The filed rate doctrine, BGE contends, is not vulnerable to exception regardless of the justification. *Id.* at 23. Last, BGE claims that AEP/Exelon's arguments opposing the ruling are meritless. *Id.*

Trial Staff and First Energy

580. During the hearing, Staff and First Energy argued that it would be more beneficial to save the issue for briefing and address it in the Initial Decision.

Discussion/Findings/Conclusions

581. Rule 217, 18 C.F.R. § 385.271 (2006) states that an issue may be resolved summarily provided that there is no genuine issue of fact material to the decision. No party has disputed CMS ERM's claim that it has not served retail load at the MECS.DECO.CMSZ sink or that it has not moved any electricity through and out of the PJM system to serve retail load at the MECS.DECO.CMSZ sink since September 2003. *See* CMS ERM Motion at 5 (citing Ex. CMS-1 at 4:22-23). At hearing, after CMS ERM renewed its motion, AEP/Exelon opposed granting the motion on the ground that it constituted retroactive ratemaking. Tr. at 1274:23-1277:1. AEP and Exelon; however, did not refute CMS ERM's claim that it did not serve load at that sink. Therefore, it is found that there are no genuine issues of fact and this issue may be resolved summarily. *See* 18.C.F.R. § 385.271. The disposition of this issue now turns on analysis of the law as interpreted by the previous decisions in this proceeding. *See* March 10 Partial ID, 114 FERC ¶ 63,037 at P 10.

582. After interpreting the Commission's orders in this proceeding, the March 10 and April 13 Partial IDs found that SECA charges cannot be shifted based on contracts that do not continue into the transition period. *See* March 10 Partial ID, 114 FERC ¶ 63,037 at P 16, April 13 Partial ID, 115 FERC ¶ 63,011 at P 9. The testimony of witness Chris Norton on behalf of AMP-Ohio was found persuasive and, accordingly, the decisions also held that the failure of a contract to extend into the transition period is an absolute limitation on the ability to impose a SECA charge on a LSE. *See* March 10 Partial ID, 114 FERC ¶ 63,037 at P 20-21, April 13 Partial ID, 115 FERC ¶ 63,011 at P 12-13. In essence, it was found that a SECA charge cannot not be shifted to the shipper nor imposed on a LSE for transactions that did not extend into the transition period. These findings are consistent with cost causation principles and Commission orders since there

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

can be no "lost" RTOR revenues when power was not delivered.[138] Further, if an entity takes no transmission service during the transition period, there is no benefit associated with the elimination of the RTORs on which to base a SECA charge.

583. CMS ERM was a LSE that provided retail electricity service in the Detroit Edison service territory (at the MECS.DECO.CMSZ) sink as an Alternate Energy Supplier licensed in Michigan. CMS ERM Motion at 5. The Midwest ISO has assessed $1.2 million in SECA charges against CMS ERM for retail load that it served at sink MECS.DECO.CMSZ for the 2002 and 2003 test periods. CMS ERM RB at 4; Tr. at 1272:5-18. CMS ERM is correct that no SECA charges should be imposed upon it for service associated with the MECS.DECO.CMSZ sink. It did not use transmission service to serve any retail load at that sink during the transition period. Tr. at 1272:5-18, CMS-1 at 6:1-4. Notwithstanding this fact, the MISO and the MISO TOs have assessed a SECA of approximately $1.2 million based on the load it served at that sink during the 2002 and 2003 test periods. Tr. at 1272:5-18, 1274:3-17.

584. As in the Partial IDs, Norton's testimony, which stated that "there should be no SECA at all, because there are no lost revenues the responsibility for which can be assessed as a result of the Commission's action" is equally as persuasive here. March 10 Partial ID, 114 FERC ¶ 63,037 at P 21 (citing AMP-1 at 34:1-5). Moreover, consistent with the finding above, since CMS ERM served no retail load at the MECS.DECO.CMSZ sink during the transition period, there are no associated "lost" revenues. The principles of cost causation and the Commission's intent as interpreted from its orders call for a finding that CMS ERM cannot be assessed SECA charges for the MECS.DECO.CMSZ sink. Therefore, the motion for summary disposition is granted. CMS ERM should not pay SECA charges for transmission service it never used.[139]

585. CMS ERM is also correct that AEP/Exelon's request for reconsideration of the ruling must be in the form of a brief on exceptions as required by Rule 711. *See* 18 C.F.R. § 385.711(a)(1)(i) (2006). Since the oral ruling granted CMS ERM's motion and postponed the written order until this initial decision,[140] AEP/Exelon must state its objections in a brief on exceptions within 30 days after issuance of this decision. *See* 18 C.F.R. §385.711 (a)(1)(i). However, since the arguments raised by AEP/Exelon are subsumed in issues addressed elsewhere in this decision they will, nonetheless, be addressed. AEP/Exelon's request for a finding that $1.2 million in SECA charges assessed to CMS ERM in the compliance filings were properly calculated has been

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[138] *See* March 10 Partial ID, 114 FERC ¶ 63,037 at P 18; April 13 Partial ID, 115 FERC ¶ 63,011 at P 10.

[139] If the Commission reverses this summary disposition it is recommended that this be considered a known and measurable change.

[140] *See* 18 C.F.R. § 385.217(d)(1)(ii)(B) (2006).

addressed in the lost revenues and rate design issues. The same finding applies to the Midwest ISO's argument that if the charges associated with the CMS ERM motion for summary disposition are to be recovered, those charges should be recovered from the entity that served the load. That argument is addressed in the same sections.

586. Next, both AEP/Exelon and CMS ERM have forwarded arguments concerning the Filed Rate Doctrine and retroactive ratemaking principles. The motion was not granted based on the Filed Rate Doctrine or retro active ratemaking arguments. It was granted based on the fact that CMS ERM "was not taking service during the transition period" at sink CMSZ. Tr. at 1369:18-21. Thus, these arguments as submitted by CMS ERM, AEP/Exelon and BGE are moot at this juncture. AEP/Exelon's arguments in support of reversing the ruling are unpersuasive and procedurally barred. Therefore, the request for reversal is denied.

B. Green Mountain

Should Green Mountain's Motion for Summary Disposition be granted?

Introduction

587. Green Mountain filed a motion for partial summary disposition on March 22, 2006.[141] At oral argument held on March 31, 2006, the motion was denied, without prejudice to being reinstated after its witness leaves the stand, on the ground that there is a genuine issue of material fact. Tr. at 618:19-631:1. On May 5, 2006, Green Mountain renewed its request for summary disposition based on the second argument in its motion. *Id.* at 1372:10-1373:16. Green Mountain's motion was granted during the hearing on May 5, 2006 with the caveat that the written order would be part of this initial decision. *Id.* at 1376:3-7. On June 9, 2006, Green Mountain filed an initial brief with arguments similar to those contained in its motion for summary disposition.

Parties' Contentions

<u>Green Mountain</u>

588. Green Mountain renewed at hearing its argument that it may not be assessed any SECA charges pursuant to the Midwest ISO tariff for the period January through March 2006. Green Mountain Motion at 13. According to Green Mountain, it served no load in the Midwest ISO footprint during that three month period and therefore should not be liable for the $2.2 million it was invoiced for each of those months. *Id.* These charges,

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[141] Green Mountain Energy Company's Motion for Partial Summary Disposition (March 22, 2006) (Green Mountain Motion).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Green Mountain asserts, are based solely on transactions that sank into its sub-zone during 2003 without regard to whether Green Mountain purchased or provided service in 2006. *Id.* at 14. Imposing such charges upon Green Mountain for a period in which it served no load, Green Mountain avers, constitutes retroactive ratemaking and violates the Filed Rate Doctrine. *Id.* at 4. In addition, at the hearing Green Mountain requested a ruling in its favor based on the same grounds as those found dispositive for granting CMS's motion for summary disposition.[142]

589. Green Mountain's reply brief claims that AEP/Exelon's request for reversal of the grant of partial summary disposition should be denied. GM RB at 31. AEP/Exelon do not dispute the facts underlying the ruling granting its motion for summary disposition, Green Mountain notes. *Id.* at 32. Green Mountain also argues that AEP/Exelon's attempt to collect a certain amount of revenue does not justify billing Green Mountain for transmission service for a period in which it supplied no power in the Midwest ISO footprint. *Id.* According to Green Mountain, the only argument raised by AEP/Exelon against the ruling is that it did not specify an alternative means of collecting the SECA charges, which they assert may result in under recovery of their lost revenues. *Id.* Thus, Green Mountain states that AEP/Exelon's request should be denied.

First Energy

590. First Energy argues the ruling granting Green Mountain's motion for summary disposition for the last three months of the transition period will result in an overall reduction in the amount of lost RTOR revenues associated with that three month period. FirstEnergy RB at 16. FirstEnergy also claims that an adjustment for a known and measurable difference could have only been made if it occurred during the test period. *Id.*

Midwest ISO Transmission Owners

591. The Midwest ISO TOs argue that if the SECA charges for the CMS ERM sub-zone are recovered, such charges should be recovered from the entity that served the load. MISO TOs IB at 46 (citing Ex. PTO-117). Green Mountain remains responsible for the SECA charges assessed for the other months of the transition period, the Midwest ISO TOs argue. *Id.* at 47. The Midwest ISO TOs contend that Green Mountain is, at a minimum, responsible for the SECA charges assessed for the other months of the transition period. *Id.*

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[142] Tr. at 1373:1-7. As discussed above, CMS was granted summary disposition based on that fact that it did not take service during the transition period. *See* Tr. at 1369:12-21.

Dayton Power and Light Company

592. Dayton claims that the TOs are not likely to recover their full amount of lost revenues as a result of any ruling that eliminates a LSE's SECA responsibility for charges assessed during periods when no service was provided. Dayton IB at 27. In addition, Dayton argues that since the Commission has ruled that TOs are entitled to recover all of their lost revenues, any elimination of SECA responsibility must be replaced by a replacement source of funding. *Id.* Dayton also contends that the over-payments the Midwest ISO has collected for existing transactions should be used to fund any SECA revenue shortfall caused by the Midwest ISO's failure to fully recover the PJM TOs lost revenues. *Id.* at 28.

American Electric Power Service Corporation and Exelon Corporation

593. AEP/Exelon's Initial Brief states that it opposed Green Mountain's motion at hearing on the ground that a ruling at that time would be premature since Green Mountain's witness, Mr. Linxwiler had not yet taken the stand and they intended to question him. AEP/Exelon IB at 46; Tr. at 1373:22-1374:4. They further argue that by granting Green Mountain's motion and relieving it of its SECA obligation for the last three months of the transition period, the ruling "threatens to undermine the principle of revenue neutrality that led the Commission to adopt the transitional SECA charge in the first place." AEP/Exelon IB at 47. In addition, they argue that by not specifying an alternative means of collecting the SECA charges assigned to Green Mountain, "the ruling threatens to impose rather than alleviate costs shifts on transmission owner's native load customers." *Id.* Accordingly, AEP/Exelon request that the ruling granting Green Mountain's motion for summary disposition be reversed. AEP/Exelon's reply brief states that Green Mountain should not be permitted to escape its lawful SECA obligations. AEP/Exelon RB at 30. They also state that the ruling granting Green Mountain's motion for summary disposition should be reversed. *Id.*

American Municipal Power – Ohio, Inc.

594. AMP-Ohio notes that it takes no position on the merits of Green Mountain's motion, but it states that Green Mountain's non-payment of its SECA obligation should not result in an increased SECA obligation for AMP-Ohio or its members. AMP-Ohio RB at 33. AMP-Ohio requests that any relief granted Green Mountain should avoid imposing Green Mountain's unpaid SECA obligations on other LSEs. *Id.* at 35. The TOs and RTOs should be required to identify the entities that served Green Mountain's former load and those entities should be assessed the SECA AMP-Ohio states. *Id.*

Discussion/Findings/Conclusions

595. Summary disposition is appropriate with regard to Green Mountain's motion since

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

there are no genuine issues of fact material to the decision. *See* 18 C.F.R. § 385.271. Green Mountain's claim (contained in its motion, at hearing and in the joint stipulation of facts), that it served no load from January through March of 2006 remains undisputed. Green Mountain Motion at 13, Tr. at 1372:15-1373:1, Ex. S-3 at 14 (citing GME-1 at 8:9-14). Dayton's contentions do not raise issues of fact, but instead raise arguments concerning its entitlement to payment of SECA charges by Green Mountain based primarily on the legal interpretation of the applicability of the EMT and accompanying schedules to Green Mountain. Similarly, the Midwest ISO TO's, AEP/Exelon's and First Energy's arguments fail to raise issues of material fact concerning Green Mountain's load during the last three months of the transition period. Furthermore, their arguments are subsumed in issues discussed under other sections of this initial decision and therefore will not be considered here. Thus, there are no issues of material fact and summary disposition is appropriate. This issue will be resolved based on the law as interpreted in the March 10 and April 13 Partial IDs and consistent with the findings stated above. See *See generally* March 10 Partial ID, 114 FERC ¶ 63,037; April 13 Partial ID, 115 FERC ¶ 63,011.

596. As discussed above under Green Mountain's SECA issues, Green Mountain is an LSE under the Midwest ISO tariff. Dayton IB at 4 (citing Midwest ISO Tariff, 3rd Rev. Vol. No. 1 at 2d Rev. Sheet No. 92 at § 1.171). Green Mountain has been assessed, by the Midwest ISO, SECA obligations allocated to the Green Mountain Energy Company sub-zone within the American Transmission Systems, Inc. (ATSI) zone of the Midwest ISO. Green Mountain Motion at 4. Green Mountain has been invoiced $2.2 million in SECA charges for each of the last three months of the transition period. *Id.* at 13. Green Mountain did not supply any power to customers in Ohio or serve any load within the Midwest ISO after January 1, 2006. Ex. S-3 at 14, GME-1 at 8:9-14, Tr. at 1374:20-22. As discussed in more detail above, the March 10 and April 13 Partial ID's found that SECA charges cannot be assessed on an LSE based on contracts that did not extend into the transition period or did not involve "delivered power" in the transition period because there are no associated "lost" revenues. March 10 Partial ID, 114 FERC ¶ 63,037 at P 21, April 13 Partial ID, 115 FERC ¶ 63,011 at P 13.

597. Although the period January 2006 through March 2006 is only a portion of the transition period, the same reasoning applies here. The SECA was designed to allow the recovery of "lost" revenues associated with the elimination of the RTORs during the transition period. March 10 Partial ID, 114 FERC ¶ 63,037 at P 11 (citing November 17 Order, 105 FERC ¶ 61,212 at P 44). It should be clarified; however, that simply because a contract for "delivered" power continued into the transition period does not give the Midwest ISO license to collect SECAs for the entire two year period without regard to whether entities served load. Green Mountain served no load in the Midwest ISO

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

footprint during those three months,[143] and accordingly, there are no associated "lost" revenues for that period as applied to Green Mountain.

598. The November 17 Order stated that "consistent with cost causation, the load of an importing utility should pay a fair share of the costs of the exporting utility's share of the costs of the exporting utility's transmission facilities for its use of those facilities." November 17 Order, 105 FERC ¶ 61,212 at P 48. In addition, the November 17 Order provided that the Commission intended "the new transition rate mechanism [to] allocate such costs in proportion to the benefits received." *Id.* Since Green Mountain served no load in the Midwest ISO footprint during the last three months of the transition period, it derived no benefit from the elimination of the RTORs for the duration of those three months. If Green Mountain served no load during that period, assessing it a SECA would be inconsistent with the transitional rate mechanism the Commission envisioned and run afoul of cost causation principles.[144] It is found that Green Mountain should not be assessed SECA charges for the three month period during which it served no load in the Midwest ISO.[145]

C. Michigan Public Power Agency

Should Michigan Public Power Agency's Motion for Summary Disposition be granted?

Parties' Contentions

Michigan Public Power Agency

599. On June 9, 2005, the Michigan Public Power Agency (MPPA) submitted an initial brief and a motion for summary disposition.[146] First, MPPA states that its Power Pool

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[143] Green Mountain's Motion states that "Green Mountain ceased doing business in the Midwest ISO region on December 31, 2005, and since that time Green Mountain has served no customers within the Midwest ISO." Green Mountain Motion at 3.

[144] *See* November 17 Order, 105 FERC ¶ 61,212 at P 48 (In explaining why the lost revenue recovery mechanisms are consistent with the principle of cost causation during the transition period, the Commission stated that it is "developing the transitional rate mechanisms to ensure that the parties continue to pay the costs of facilities that they use and from which they benefit").

[145] If the Commission reverses this finding it is recommended that this be considered a known and measurable change.

[146] Initial Brief and Motion for Summary Judgment of the Michigan Public Power Agency (June 9, 2005).

Project purchased 100,512 MW of energy from AEP that was transmitted across the PJM/MISO seam. MPPA IB at 7 (citing Ex. MPPA-1 at 18:14-16, Ex MPPA-2). Approximately 60,577 of those MWs were imported in January and February of 2002 as a result of tornado damage to its Lansing Erikson generating unit and the Belle River unit being made unavailable due to scheduled maintenance. *Id.* (citing MPPA-1 at 18:16-18, 19:17-21, 20:1-6; Ex. MPPA-2; Tr. at 1455:8-211; Ex. MPPA-1 19:17-19). Once the Lansing Erikson unit came back online, in February of 2002, MPPA claims it no longer needed to import power from AEP causing its purchases from AEP to decrease by approximately 92 percent. *Id.* at 8 (citing MPPA-2).

600. MPPA notes that its purchases from AEP dropped to 39,890 MW in 2003 and 21,404 from January 1, 2004 to November 20, 2004. *Id.* (citing Ex. MPPA-2). In addition, MPPA states that since the beginning of the transition period, MPPA has only purchased 4,272 MW from AEP that was transmitted across the PJM/MISO seam and provided pursuant to short-term contracts executed after the test period. *Id.* (citing MPPA-2). Finally, MPPA claims that its purchases from AEP were zero from April 2005 to March 2006. *Id.*

601. Next, MPPA argues that all of its test period contracts expired prior to the transition period. *Id.* at 9. According to MPPA, the Midwest ISO has billed it for SECA charges based on its short term transactions during the 2002 and 2003 test periods. *Id.* Since these transactions were short-term or hourly contracts, MPPA claims, none of the contracts with AEP continued into the transition period as required by the Commission. *Id.* at 9, 11. This evidence is uncontested, MPPA states. *Id.* at 11. For this reason, MPPA claims that it should not be assessed SECA liability for the AEP contracts. *Id.* at 9. Moreover, MPPA claims that assessing a SECA against it would violate cost causation principles. *Id.* at 12. AEP, MPPA contends, has not provided evidence to contest any of MPPA's evidence. *Id.* Specifically, MPPA argues that AEP has not provided evidence proving that MPPA is still using AEP's system to transport power across the MISO/PJM seam or evidence showing that the transactions that terminated prior to the transition period were subsequently replaced with new transactions. *Id.* Since April 1, 2005, MPPA claims, it has made no purchases from AEP. *Id.* MPPA states that the only transactions that took place in the transition period were entered into after the test period and, therefore should not be included in the SECA calculations. *Id.* at 11. Accordingly, MPPA requests a finding that it has no SECA liability and that it should be refunded, by the Midwest ISO, all SECA charges imposed on and paid by it, with interest. *Id.* at 17.

602. Third, MPPA argues that its purchases from AEP in January and February 2002 were significantly higher that its purchases during the remaining months of the period. *Id.* at 13 (citing Tr. 1456:7-22, Ex. MPPA-2). MPPA states that its witness Mr. Cooper testified that the imports made during those months were only entered into to replace capacity lost by the damage to the Lansing Erikson unit and were not representative of normal operations. *Id.* (citing Ex. MPPA-1 at 19:15-21, 20:1-6; Ex. MPPA-2; Tr.

1456:7-22). Thus, MPPA argues, these purchases are known and measurable differences worthy of an adjustment to represent MPPA's purchasing practices. *Id.* If MPPA is not granted summary disposition, it requests in the alternative, an adjustment for known and measurable changes. *Id.* at 14. Finally, MPPA contends that the standard for summary disposition has been satisfied since the record concerning MPPA's SECA liability to AEP is undisputed. MPPA specifically states that AEP did not submit answering testimony in response to Mr. Cooper's testimony, object to Mr. Cooper's testimony during cross examination or object to MPPA's exhibit detailing MPPA's power purchases. *Id.* at 15.

American Electric Power Service Corporation and Exelon Corporation

603. AEP/Exelon argue that MPPA's motion for summary disposition should be rejected. AEP/Exelon RB at 41. The evidence in the record, AEP/Exelon claims, does not support the elimination of all of MPPA's SECA obligations to AEP and the other TOs. *Id.* Specifically, AEP/Exelon point to the fact that Mr. Cooper's testimony is devoid of information about the expiration date of MPPA's power supply contracts in the test years, after the test years and during the transition period. *Id.* AEP/Exelon further assert that MPPA is being misleading by asserting that Mr.Cooper's testimony does contain this information. *Id.* (citing MPPA I.B. at 9, 16). Thus, AEP/Exelon argue it is unfair for MPPA to argue that AEP failed to prove that the transactions the expired before the transition period were later replaced with new transactions. *Id.* at 42.

604. In addition, AEP/Exelon claims that MPPA's use of Exhibit No. MPPA-2 as a basis for eliminating all of its SECA liability is without merit. *Id.* Specifically, AEP/Exelon state that Mr. Cooper stated that Exhibit No. MPPA-2 contains no information regarding MPPA's imports across the PJM/MISO seam from third parties other than AEP's power marketing affiliate. *Id.* (citing Tr. at 1444). Thus, AEP/Exelon argue that the exhibit provides misleading information on MPPA's imports since the it only shows MPPA's purchases from AEP's market affiliate. *Id.* AEP/Exelon also claim that MPPA did not introduce or attach any of its contracts into the record. *Id.* at 42 n.135.

605. Second, AEP/Exelon contend that MPPA has misinterpreted the Commission's orders and incorrectly applied the Partial Initial Decisions. *Id.* at 43. MPPA, AEP/Exelon claim, uses the Commission's orders for the proposition that MPPA's usage during the transition period should be used instead of test period data as mandated by the Commission. *Id.* AEP/Exelon also state that MPPA has improperly used the Partial IDs, which have only been narrowly applied to shift-to-shipper claims, to relieve itself of SECA liability. *Id.* at 44.

606. Third, AEP/Exelon argue that MPPA's adjustment for known and measurable changes is unsupported. *Id.* This is because, AEP/Exelon asserts, MPPA has not provided information comparing its monthly imports during the test years to its import activity in previous years to show whether January and February deliveries are as atypical

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

as they claim. *Id.* at 45. Similarly, MPPA has not provided historical information regarding the outage and maintenance histories for the units MPPA claims are the source of these unanticipated purchases AEP/Exelon claim. *Id.* AEP/Exelon suggest that this information is needed to determine whether the combination of outages was unusual or and whether the depletion of capacity reserves was beyond MPPA's control as MPPA claims. *Id.*

607. AEP/Exelon also claim that MPPA-2 does not provide sufficient factual support for MPPA's proposed known and measurable changes adjustment because it does not reflect MPPA's total usage of AEP's transmission facilities for deliveries of energy to MPPA from sources other than AEP that were scheduled for delivery using AEP's transmission service. *Id.* at 46. Thus, AEP/Exelon contend, the exhibit is an incomplete representation of MPPA's usage of AEP's transmission facilities. *Id.* at 47. AEP/Exelon also claim that it has been demonstrated that MPPA's close proximity makes it inevitable that MPPA will have to use AEP's transmission facilities regardless of which entity outside of Michigan MPPA is purchasing power from. *Id.* Finally, AEP/Exelon assert that even if MPPA has provided adequate support for its known and measurable changes adjustment, the proposed adjustment results in a meager 2.7% reduction of MPPA's SECA obligation to AEP. *Id.* AEP/Exelon state that if the Commission finds that MPPA has demonstrated that the actual amount of energy purchased from AEP by MPPA during January and February 2002 warrants adjustment, 9000 MWs is a more reasonable estimate. *Id.*

Discussion/Findings/Conclusions

608. MPPA is a Michigan LSE and a municipal joint action agency that provides services necessary to meet the electric power supply needs of the municipal electric systems of MPPA members.[147] Some of MPPA's members own "sizeable" amounts of generating capacity and, in addition, MPPA's members also rely on smaller generating units owned by certain members. Ex. MPPA-1 at 11. Occasionally, MPPA purchases wholesale electric energy when needed or economically beneficial.[148]

609. Summary disposition is not appropriate with respect to this issue. MPPA's motion is based on the claim, which is misplaced, that it cannot be assessed SECA charges because all of its test period contracts expired prior to the transition period.[149] As articulated in the March 10 Partial ID, "the Commission envisioned that the SECA would

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[147] Ex. MPPA-1 at 23:8-24:11; MPPA IB at 6-7 (citing MPPA-1 at 1:10-14).

[148] MPPA IB at 7 (citing MPPA-1 at 1:15-17).

[149] *See Id.* at 11 ("[t]he only transactions that took place during the transition period were entered into *after* the test period, and thus are not transactions that should be included in the SECA calculation.").

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

apply to transactions involving reservations pursuant to requests made on or after November 17, 2003 for service commencing after April 1, 2004." March 10 Partial ID, 114 FERC ¶ 63,037 at P 16. The March 10 Partial ID also provides that "SECA charges should not be imposed on contracts that do not continue into the transition period." *Id.* at 17. However, the Commission did not impose a requirement that the contracts be executed during the test period to charge a SECA. Thus, while the contracts which terminated prior to the transition period are not SECA eligible, MPPA's other purchases made during the transition period qualify for such an assessment. MPPA's motion has not presented facts sufficient to support a conclusion that all of its SECA liabilities should be eliminated.

610. It is undisputed that MPPA's test period contracts for 140,402 MW of imports from AEP all terminated prior to the beginning of the transition period.[150] AEP/Exelon's arguments at hearing and in their brief assert that the information presented by MPPA's Exhibit No. MPPA-2 with regard to this fact is incomplete, but at no time do they assert that it is incorrect. AEP/Exelon RB at 42-43; Tr. at 1463:6-1466:2. MPPA is requesting a ruling that it has no SECA liability. Albeit the facts are undisputed, MPPA has not made its case for summary disposition since even as its own Exhibit No. MPPA-2 shows, it had imports during the transition period. Accordingly, MPPA's motion for summary disposition is denied and AEP is correct that MPPA is not entitled to have its entire SECA liability eliminated. Although MPPA asserts it made no purchases from AEP after April 1, 2005 it does not follow that it is not liable for SECA charges associated with other purchases.

611. If the Commission accepts the compliance filings as filed, MPPA's assessed SECA charges would require an adjustment for known and measurable changes pursuant to the July 23 Order. *See* July 23 Order on Initial Decision, 104 FERC ¶ 61,105 at P 54. MPPA's 140,402 MW purchase from AEP during the period beginning January 2002 through December 2003, which did not continue into the transition period, should be excluded from the SECA. This adjustment is not based on MPPA's assertion that 2002 was an atypical month for purchases. Thus, AEP/Exelon's related arguments are moot. AEP/Exelon RB at 44-47. Accordingly, summary disposition is partially granted as discussed here solely to make adjustments for contracts that did not continue into the transition period. AEP/Exelon's concern that Exhibit No. MPPA-2 may paint a misleading picture is also rendered moot since this finding is limited to MPPA's purchases from AEP and has not been expanded to SECA charges from other TO's.

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[150] MPPA IB at 11-12; Ex. MPPA-2 (MPPA's 2002 purchases for MPPA load and resale in the amounts of 84,583 and 15,929, respectively plus MPPA's 2003 purchases for load and resale in the amounts of 31,938 and 7,952, respectively yield a total test period MPPA purchase amount from AEP of 140,402 MW).

Moreover, based on the findings above, MPPA's SECA obligations will have to be recalculated which may make most of their arguments moot.

D. Old Dominion Electric Cooperative

Should Old Dominion Electric Cooperative's (ODEC) Motion for Summary Disposition be granted?

Parties' Contentions

Old Dominion Electric Power Cooperative

612. The Multiple TDUs[151] and, in particular, ODEC filed a motion for partial summary disposition on March 13, 2006. The motion was denied from the bench after oral argument held on March 31, 2005. Tr. at 585. ODEC[152] renewed its motion in the Four TDUs reply brief submitted on June 27, 2006.[153] Four TDU's RB at 7. ODEC requests summary disposition on the ground that the 709,664 MW associated with the ODEC Ironwood contract should be excluded from its SECA obligation because the contract did not continue into the transition period and was not replaced with other imports that crossed the seam during the transition period. *Id.* at 3, 6. According to ODEC, these facts are undisputed in the record. *Id.*

613. ODEC entered a contract with Williams Energy Marketing & Trading Company for the delivery of 490 MW of firm capacity and energy for power generated at the AES Ironwood plant within the Classic PJM (hereinafter the Ironwood contract). *Id.* at 8; Ex. MTDU-67. ODEC had a transmission reservation to deliver the power across the PJM-Dominion Virginia Power (DVP) border to ODEC. *Id.* at 8. The contract and the reservation terminated by their own terms in May 2003. *Id.* (citing Ex. MTDU-10 at 4-

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[151] The Multiple TDUs that joined in the motion are listed in the first footnote in that document.

[152] Although the initial brief was submitted by the Four TDUs, this section will refer to the Four TDUs as ODEC for the sake of clarity. The Four TDUs that filed this brief are Old Dominion Electric Cooperative (ODEC), Blue Ridge Power Agency (Blue Ridge), Central Virginia Electric Cooperative (CVEC), and Indiana Municipal Power Agency (IMPA) (collectively, the Four TDUs).

[153] On June 27, 2006 the Four TDUs filed a notice/motion requesting leave to file a brief to address the merits of their disputes with BGE. They state that they previously did not address the issues because the Multiple TDUs anticipated filing a settlement with BGE relating to the Multiple TDUs SECA payments to BGE. On June 30, 2006, BGE filed a response stating that it does not oppose the motion. Thus, there is good cause to accept the Four TDUs reply brief and no party will be harmed by its acceptance.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

5.[154] A total of 709,664 MW were imported under this transaction during 2003. MTDU I.B. at 10. ODEC states that it paid approximately $5,096,000 for this transmission which was distributed to BGE. *Id.* at 10.

614. Mr. David J. Scarpignato, the Multiple TDU's witness, stated that this test period purchase is not representative since this transaction will not reoccur, ODEC claims. *Id.* at 8. According to ODEC, Mr. Scarpignatto also states that this is because ODEC was building a new combustion turbine plant which has eliminated the need to meet its capacity requirement with the AES Ironwood plant and ODEC has made arrangements for in-zone generation so that it no longer needs to make significant purchases across the PJM-DVP border. *Id.* at 9 (Ex. MTDU-10 at 5-6). Mr. Scarpignatto also stated that under reservation 70514 which was used to import the Ironwood plant imports 709,664 MW were delivered, ODEC contends. *Id.* at 10 (citing Ex. MTDU-10 at 5-6). ODEC states that Mr. Scarpignatto's testimony regarding the facts related to the Ironwood contract adjustment have not been disputed and all the parties waived cross-examination of Mr. Scarpignatto. *Id.* at 10, 11. In addition, ODEC states that it is undisputed that its usage of transmission across the border into DVP during the test period has been significantly lower during the transition period. *Id.* at 12. ODEC claims that the removal of the MW related to the Ironwood contracts will result in a 64.8% reduction of ODEC's SECA obligation. *Id.* at 14. BGE, ODEC contends has also admitted that a SECA can only be charged based on contracts for delivered power that continue into the transition period. *Id.* at 5. In conclusion, ODEC avers that based on the Partial IDs, SECA charges paid by ODEC to BGE should exclude the charges related to the Ironwood contracts. *Id.* at 13.

Discussion/Findings/Conclusions

615. Summary disposition is appropriate with respect to this issue since the dispositive facts have been stipulated by the parties rendering the facts undisputed.[155] The following relevant facts have been stipulated by the parties:

> During the first five months of 2003, ODEC had a contract with Williams Energy Marketing & Trading Company (Exh. MTDU-67) for power sourced and sold at the AES Ironwood generating plant in South Lebanon, Pennsylvania, located within "Classic" PJM.

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[154] Ex. MTDU-10 is protected. Therefore, the citations to this exhibit are limited to those contained in the public version of the document.

[155] *See* 18 C.F.R. § 385.217; *see* March 10 Partial ID, 114 FERC ¶ 63,037 at P 10 ("if there are no genuine issues of fact material to the decision, the matter may be resolved summarily");.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

> In order to import the Ironwood capacity and any associated energy, ODEC obtained a 490 MW transmission reservation (No. 70514) on the path from Ironwood to the DVP zone.
>
> That contract expired on May 31, 2003.
>
> Reservation No. 70514 expired contemporaneously with the Ironwood power contract, on May 31, 2003, and was not rolled over.
>
> In approximate numbers, out of the 1.1 million MWh shown in the tag set as delivered from PJM into ODEC-Dominion during 2003, 0.7 million MWh were delivered using Reservation No. 70514.

Ex. S-3 at 13. In addition, ODEC states that the testimony of Mr. Scarpignatto remains undisputed. Four TDUs RB at 7. The applicable law, as succinctly stated in the March 10 Partial ID, provides that "SECA charges should not be imposed on contracts that do not continue into the transition period." March 10 Partial ID, 114 FERC ¶ 63,037 at P 17. The Ironwood contract and the associated transmission reservation No. 70514 terminated simultaneously on May 31, 2003. Ex. S-3 at 13. These contracts clearly expired before the transition period began on December 1, 2004 and therefore should not give rise to a SECA charge. The findings above in the test period section will exclude the Ironwood contract as well as other contracts that did not extend into the transition period. Such transactions will also be excluded because they were contained solely within PJM (see discussion in lost revenues above).

616. Summary judgment is granted to remove from the SECA obligations those contracts that did not continue into the transition period.[156] Accordingly, ODEC's motion is granted, and its SECA obligation to BGE must be adjusted to exclude the 709,664 MW imported in 2003 under the Ironwood contract. *See* Four TDUs RB at 10, 14. The amount of any resulting overpayment shall be refunded with interest. Notably, the majority of ODEC's arguments may be rendered moot as the rate design findings herein require ODEC's SECA obligations to be recalculated.

E. Ormet Primary Aluminum Corporation

Should Ormet's Motion for Summary Disposition be granted?

Parties' Contentions

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[156] If the Commission rejects this ruling the contract termination may be considered a known and measurable change.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

Ormet Primary Aluminum Corporation

617. On March 20, 2006 Ormet filed a motion for summary disposition which was denied, without prejudice at oral argument held on March 31, 2006.[157] Ormet renewed that motion at hearing on May 18, 2006. Tr. at 2270:21-2272:24. The ruling on the motion was deferred in the interest of allowing the parties to brief the issue. Tr. at 2299:1-16. Ormet's motion for summary disposition is based on three grounds "(1) the proposed SECA constitutes retroactive ratemaking, (2) the proposed SECA for Ormet must be adjusted for known and measurable changes in Ormet's load, and (3) Ormet's supply contracts, now expired, should not be used to determine Ormet's SECA obligation." Ormet RB at 35-36.

618. Ormet first argues that the TOs attempt to recover the same revenues received in 2002 and 2003 violates the filed rate doctrine and the doctrine against retroactive ratemaking. Ormet Motion at 10. Specifically, Ormet claims that basing its SECA charges on its usage during the test period does not reflect, and in fact overstates, its usage during the transition period. *Id.* at 11. The Commission has not ruled on this argument, Ormet contends, because the SECA addressed in the Commission's November 17 Order differs from the SECA at issue in this proceeding. *Id.* Ormet argues that the retroactive ratemaking issue can be resolved by calculating a "per unit rate based upon the test period usage and revenues and apply that rate to the transition period usage."[158]

619. Next, Ormet argues that its 535 MW test period load decreased during the transition period to 8 MW on December 20, 2005. *Id.* at 14 (citing ORM-1 at 5). This substantial decrease, Ormet contends, should be reflected in its SECA calculations. *Id.* at 13. Ormet asserts that an adjustment to its SECA charge based on this known and measurable change complies with the Commission's orders. *Id.* As of December 31, 2004, Ormet contends, it has purchased no power outside of PJM. Ormet IB at 51. Finally, Ormet claims that, based on the March 10 Partial ID it should not be required to pay SECA charges based on its Supply Contracts[159] after December 31, 2004, the date those contracts terminated or were no longer applicable to Ormet. Ormet Motion at 18.

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[157] Tr. at 570:1-15. Several parties filed answers to Ormet's motion on March 27, 2006.

[158] *Id.* at 12 (citing Ex. ORM-2 at 36-38; *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,212 at P 21 n.37, P 26, P 50 (2003)).

[159] EKT, Ormet Primary's Energy Manager, had contracts with Cincinnati Gas & Electric Company, PSI Energy, Inc. and Cinergy Services Corporation (collectively, Cinergy); Commonwealth Edison Company (ComEd); and PECO Energy Company (collectively, the Supply Contracts).

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

These issues have been discussed by Ormet's witness Whitfield Russell and according to Ormet, no party has rebutted Mr. Russell's evidence. Ormet RB at 37.

620. In its reply brief, Ormet argues that the SECA is meant to reflect activity during the Transition period. *Id.* at 19. The test years, it asserts, are only supposed to be a proxy and therefore must be adjusted for known and measurable differences. *Id.* at 20. Ormet further argues that adjustments for known and measurable differences are not just for events that occurred in the test period as AEP/Exelon assert because the rates must reflect future purchases. *Id.* In addition, Ormet asserts that adjustments for grandfathered contracts and hubbing do not satisfy the requirement for known and measurable adjustments because these adjustments serve entirely different purposes. *Id.* at 21. Thus Ormet claims, adjustments for grandfathered contracts and hubbing alone will not enable test year data to more closely reflect trading patterns during the transition period. *Id.* (citing November 17 Order, 105 FERC ¶ 61,212 at P 61, 64). Ormet also states that the proposed standard for known and measurable differences presented by AEP/Exelon is inconsistent with the Commission's standard. *Id.* at 23. If a standard should be used, Ormet argues, the standard should be whether making a known and measurable adjustment would cause the test years to more closely approximate Transition period usage. *Id.* However, Ormet states that regardless of which standard of which standard is used it has still demonstrated a known and measurable change that warrants an adjustment to its SECA obligation. *Id.* at 24.

621. Ormet also argues that its known and measurable differences are unrelated to the elimination of the RTORs and that contrary to AEP/Exelon's assertions, were actually caused by events such as its bankruptcy proceeding and sale of the rolling mill. *Id.* (citing Tr. 2211:20-2214:3, 2215:4; Ex. ORM-1 at 3:9-15). In addition, Ormet argues that AEP/Exelon's arguments opposing its requested adjustments is inconsistent because AEP/Exelon first argued that if Ormet has an argument for the reduction of its SECA, it would be based on known and measurable changes in its load, but AEP later argue that Ormet would not qualify for such an adjustment because the adjustment would have to be to the test period based on prior factors. *Id.* at 25 (citing AEP/Exelon I.B. at 34, 36). Ormet also mentions that AEP witness Bethel admitted that Ormet may have a point that a known and measurable change adjustment is warranted. *Id.* at 26.

American Electric Power Service Corporation and Exelon Corporation

622. AEP/Exelon's initial brief reiterates Exelon's objections to Ormet's motion made during the hearing.[160] First, AEP/Exelon argue that the filed rate doctrine and retroactive

[160] Tr. at 2272:25-2274:5. AEP/Exelon also note that it incorporates by reference the arguments in its previously filed answer on this issue. AEP/Exelon IB at n.127 need page.

ratemaking are not at issue in this proceeding and therefore cannot serve as the basis for granting Ormet's motion. AEP/Exelon I.B. at 48. Second, AEP/Exelon contend that Ormet has not supported its proposed adjustment for known and measurable changes. *Id.* According to AEP/Exelon the burden of supporting adjustments for known and measurable differences lies with the proponent and Ormet has not met the burden because the only known and measurable differences that should be considered are those known during the test period. *See id.* at 36-39, 48. Last, AEP/Exelon state that although Ormet contends that its 2002 and 2003 supply contracts terminated on December 1, 2004, Ormet should still be assessed a SECA to the extent that it purchased power from the PJM market. *Id.* at 49. Thus, AEP/Exelon conclude, Ormet's motion should be denied.

623. AEP/Exelon's reply brief argues that Ormet's request for a known and measurable adjustment should be rejected because it concerns generic rate design issues not specific to Ormet. AEP/Exelon R.B. at 32. They further argue that the reductions in Ormet's load are not the type of anomalous occurrences contemplated by the Commission in the Order on Rehearing. *Id.* AEP/Exelon state that, contrary to Ormet's arguments, the placement of Ormet in its own sub-zone is fair and appropriate because Ormet's service differs from the other retail and wholesale customers of AEP. *Id.* at 33.[161]

American Municipal Power – Ohio, Inc.

624. AMP-Ohio notes that it takes no position on the merits of Ormets request. However, if Ormet's request is granted, AMP-Ohio requests that the relief be fashioned to recognize Ormet's reduced load as a known and measurable change to reflect that the reduction in RTOR lost revenues is the result of Ormet's operations (and not by the Commission's elimination of the RTORs). *Id.* at 34.

Discussion/Findings/Conclusions

625. Ormet's arguments regarding retroactive ratemaking and its proposal to revise the calculations to base the per unit rate on test period data and apply that rate to transition period usage have been addressed in the Rate Design and Lost Revenues sections above. The sections contemplate new filings based on transition period usage. Thus, the arguments presented addressing this issue are subsumed in those sections and will not be disposed of here.[162]

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[161] The sub-zone issues have been addressed under issue 3.C above and, therefore are not discussed in the ruling on this motion.

[162] AEP/Exelon's arguments concerning that issue are also subsumed in that section and will not be discussed here.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

626. Second, the TO's in their compliance filings, seek to collect a SECA based on Ormet's test period usage of 535 MW. Ormet RB at 18 (citing Ex. ORM-2 at 41:11-42:2). Ormet's energy requirements fell to 8 MW during the transition period. *Id.*, Ex. S-3 at 11-12. Ormet's request for a known and measurable difference adjustment to account for this substantial decrease in load has been granted above. The findings concerning the rate design reject the compliance filings for failure to comply with the Commission's mandates and contemplates new filings in which the SECA charges will be assessed based on transition period usage. Thus, the ruling addresses Ormet's other concerns. These findings put into effect the Commission's guideline that the compliance filing "most closely reflect future trading patterns." *See* July 23 Order, 104 FERC ¶ 61,105 at P 54.

627. Last, Ormet's Supply Contracts either terminated or were no longer applicable to Ormet as of December 31, 2004. Ex. ORM-1 at 5. Thus, the contracts continued into the transition period, but only existed for one month of the period's sixteen month duration. As discussed above with regard to Green Mountain's motion for summary disposition, contracts that only existed for a portion of the transition period cannot serve as the basis of SECA charges beyond that contract's duration. Therefore, Ormet should only be assessed a SECA for the Supply Contracts for the period December 1, 2004 though December 31, 2004, or one month. *See* Ex. ORM-1 at 5. By virtue of the rate design findings and conclusions above, the inclusion of Ormet's Supply Contracts in the SECA calculations will be limited to the portion of those contracts that extended into the transition period. AEP/Exelon argue that Ormet should still be assessed a SECA to the extent that it purchased power from the PJM market although Ormet's supply contracts ended on December 1, 2004. To the extent that Ormet purchased power during the transition period the new filings, as contemplated by the findings above, will impose SECA charges based upon such purchases. Accordingly, summary disposition is partially granted with respect to Ormet's Supply Contracts. *See* 18 C.F.R. § 385.271. Ormet should not be held liable for SECA charges related to its Supply Contracts after their termination date of December 31, 2004.[163]

V. CONCLUSIONS

628. Based on the above it is concluded that the compliance filings are rejected because they result in unfair, unjust and discriminatory rates. It was concluded that use of calendar year 2002 is unreasonable among others since it recovers T&O revenues that have already been paid and is not reflective of future trading patterns. It is recommended that more recent data be used such as the 2003 historical throughput, adjusted for known and measurable changes. The TOs failed to comply with Commission requirements by

[163] If the Commission reverses this finding, then the contract termination should be considered a known and measurable change.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

not making adjustments for known and measurable changes. In addition, it was concluded that the TOs did not support their T&O revenues and their lost revenues. Moreover, the TOs failed to comply with Commission requirements by including items in their lost revenue calculations which had been expressly excluded by the Commission. For instance, the TOs included transactions that did not sink inside the combined region which inflated their revenues. Additionally, the TOs included inter-affiliate transactions in their lost revenue calculations. This was found to be unjust and unreasonable since inter affiliate transactions do not provide net revenues and the inclusion of such transactions creates a financial windfall for the utilities.

629. In addition, it was concluded that the rate design in the compliance filings was flawed. This was due to the fact that the compliance filings guarantee that SECA revenues during the transition period equal T&O revenues from the historical period. This is contrary to Commission guidelines for the SECA and cost causation principles. It is recommended that an alternative proposal be adopted (SECA rates developed in the traditional manner-by dividing test year revenues by test year load (MWh)-the resulting per unit MWh SECA rate is applied to actual monthly billing determinants for the transition period. Additionally, it was concluded that the sub-zone allocation in the compliance filings produced unjust and unreasonable results and was contrary to cost causation principles. Also recommended is the adoption of one combined zone with a single footprint. The ID rejects the arguments that the ET RTORs be capped at the SECAs.

630. The ID grants the ship to shipper claims of the Michigan LSEs and Quest/ESI and the ripple claim of CCG. Additionally, it concludes that Green Mountain was properly assessed SECA obligations. Finally, the ID grants a number of summary dispositions along the lines of previously issued Partial IDs in this proceeding.

VI. ORDER

631. **IT IS ORDERED**, subject to review by the Commission on exceptions or on its own motion, as provided by the Rules of Practice and Procedure, that within thirty (30) days of issuance of the final order of the Commission in this proceeding, the TOs shall file revised compliance filings in accordance with the findings and conclusions of this ID, as adopted or modified by the Commission.

632. It is noted that a number of exhibits have been modified and withdrawn as a result of settlements. The record is reopened: (1) to accept Constellation Exhibit No. CCG-6 revised on July 24, 2006 pursuant to its Notice Regarding Scope of Testimony and Exhibits filed on June 13, 2006 and; (2) to accept modifications to admitted exhibits and

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

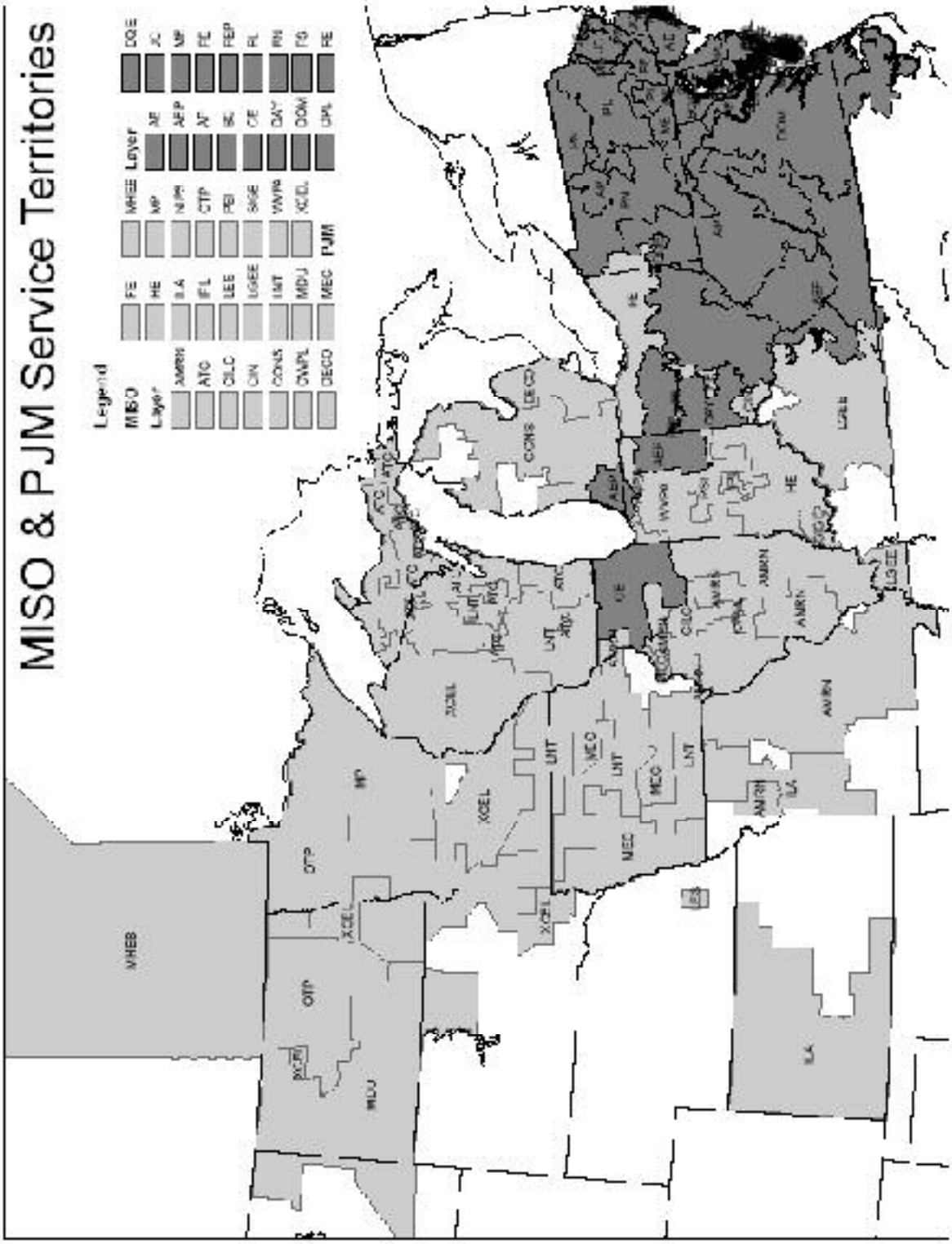
633. the withdrawal of exhibits pursuant to settlements which have been approved by the Commission since the closing of the record (May 18, 2006).

Carmen A. Cintron
Presiding Administrative Law Judge

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002

APPENDIX

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002



Source: Exhibit Nos. RTO 4-5.

MISO & PJM
SERVICE TERRITORIES MAP
LEGEND DECODER

MISO:	PJM:	OTHER:
AMRN – Ameren ATC - American Transmission Co. CILC - Central Illinois Light Company CIN - Cinergy CONS - Consumers CWLP - City Water Light and Power (Springfield, IL) DECO - Detroit Edison Company FE - First Energy HE - Hoosier Energy R.E.C. ILA - Aquila IPL - Indianapolis Power and Light LES - Lincoln Electric System (NE) LGEE - Louisville Gas and Electric LNT - Alliant MDU - Montana Dakota Utilities MEC - Mid American Electric Co. MHEB - Manitoba Hydro MP - Minnesota Power NIPS - Northern Indiana Public Serv. OTP - Otter Tail Power PSI - Cinergy SIGE - Vectren WVPA - WVPA R.E.C. XCEL - Xcel Energy	AE - Atlantic City Electric AEP - American Electric Power AP - Allegheny Power BC - Baltimore Gas and Electric CE - Commonwealth Edison DAY - Dayton Power and Light DOM - Dominion DPL - Delaware Power and Light DQE - Duquesne Light JC - Jersey Central Power and Light ME - Metropolitan Edison PE - PECO Energy PEP - Potomac Electric Power PL - PPL Electric Utilities PN - Pennsylvania Electric PS - Public Service Electric and Gas RE - Rockland Electric	CITIZ - Citizens Electric Corp CNXUS - Connexus energy EIA - Eastern Iowa L&P Coop EMDE - Empire District Electric GTL - Great Lakes Energy Coop KCPL - Kansas City Power and Light KE - Kenergy Corp KGE - KGE a Western Rsrcs. Co. NPPD - Nebraska Public Power Dist. OPPD - Omaha Public Power District OWEN - Owen Electric Coop PRECC - Pennsylvania Rural Electric Coop. STJ - St. Joseph Light and Power WA - Warren Rural Electric Coop

Source: Exhibit No. RTO-6.

20060810-3019 Issued by FERC OSEC 08/10/2006 in Docket#: ER05-6-002