136 FERC ¶ 61,244
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc.	Docket Nos. ER05-6-043 ER05-6-114
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC	EL04-135-045 EL04-135-117
Midwest Independent Transmission System Operator, Inc. PJM Interconnection, LLC	EL02-111-063 EL02-111-135
Ameren Services Company	EL03-212-059 EL03-212-131
Midwest Independent Transmission System Operator, Inc.	ER05-1423-001

ORDER DENYING REHEARING

(Issued September 30, 2011)

1. In May 2010 the Commission issued an Order on Initial Decision[1] in which it affirmed, in part, and reversed, in part, two partial initial decisions, issued on March 10, 2006,[2] and April 13, 2006,[3] and an Initial Decision issued on August 10, 2006.[4] The

[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,173 (2010) (Order on Initial Decision).

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

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 63,011 (2006)

(continued…)

decisions addressed various compliance filings implementing a transitional sixteen-month lost revenue recovery mechanism that was a component of the rate design that the Commission adopted to replace rate pancaking within the combined Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM) region, which the Commission had found to be unjust and unreasonable. In this order, we deny the requests for rehearing of the Order on Initial Decision.

I. Background

2. In July 2002, the Commission accepted the choices of American Electric Power Service Corporation (AEP), Commonwealth Edison Company and Commonwealth Edison Company of Indiana (collectively, ComEd), and the Dayton Power and Light Company (Dayton) to join PJM.[5] In so doing, the Commission found that those Regional Transmission Organization (RTO) choices would result in an elongated and highly irregular seam between Midwest ISO and PJM that would "island" portions of Midwest ISO (Wisconsin and Michigan) from the remainder of Midwest ISO and would divide highly interconnected transmission systems across which substantial trade takes place. The Commission found that, without mitigation, the seam would subject a large number of transactions in the region to continued rate pancaking, impeding the goals of Order No. 2000.[6] Therefore, as a condition of accepting those RTO choices, the Commission required parties in the region to address the problem of rate pancaking across the Midwest ISO-PJM seam. Accordingly, the Commission instituted a proceeding under section 206 of the Federal Power Act (FPA)[7] to investigate the rates for service between the two RTOs and established trial-type hearing procedures.

(April 13 Partial Decision).

[4] *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 63,030 (2006) (Initial Decision).

[5] *Alliance Co.*, 100 FERC ¶ 61,137 (2002), *order on reh'g*, 103 FERC ¶ 61,274 (2003).

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

[7] 16 U.S.C. § 824e (2006).

3. Following the hearing, the Commission found the rates for service through or out of one RTO to serve load in the other RTO (i.e., regional through-and-out rates) to be unjust and unreasonable.[8] The Commission adopted a license plate rate design for the region and found that the Seams Elimination Charge/Cost Adjustment/Assignment (SECA),[9] if properly structured, could serve as a reasonable transitional mechanism to mitigate abrupt cost shifts resulting from the replacement of rate pancaking with license plate rates. Under the SECA, local loads and network transmission customers would pay (and ultimately did pay for 16 months) a transition, i.e., SECA, charge and now receive long term non-pancaked rates across PJM and Midwest ISO, two large regions with numerous resources. However, the Commission found that the record at that time was inadequate to establish the SECA as a just and reasonable replacement rate and adopted a license plate rate design without the SECA.

4. As proposed by the sponsoring transmission owners, the SECA would be derived using historical test-period data and would assign lost revenue responsibility to the load in each license plate pricing zone. Specifically, the revenue responsibility for each zone would be based on the amount of energy in megawatt hours (MWh) that sank in the zone during the test period that crossed the Midwest ISO-PJM seam (determined using North American Electric Reliability Corporation tag data and excluding transactions under grandfathered agreements) multiplied by the average regional through-and-out revenues per MWh of the transmission providers involved in the transaction across the Midwest ISO-PJM seam. The zonal revenue responsibility would then be divided by the total load in the zone and firm point-to-point transactions sinking within the zone, excluding grandfathered transactions, resulting in the per-unit zonal SECA charges that would be

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[8] *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,105 (2003) (July 2003 Order).

[9] The SECA would be a non-bypassable surcharge to license plate zonal rates for delivery to load within the combined region (i.e., within the Midwest ISO-PJM footprint). The SECA would recover revenues that would be lost due to the elimination of rate pancaking from loads in each RTO based on the revenues received in a recent historical test period associated with transactions to serve that load. During the transition period, the load in each license plate pricing zone in the importing RTO would pay approximately the same amount in the aggregate through the SECA surcharge as had been previously paid through regional through-and-out rates for service to such load. However, the surcharges would be designed as a uniform rate to be assessed on all deliveries to loads within the zone within the importing RTO, not just those deliveries associated with through-and-out transactions.

assessed on the actual demand of each load-serving entity taking service in the zone for each month that the SECA is in effect.

5. The Commission later granted rehearing, adopting the SECA, delaying the replacement of rate pancaking, and ordering compliance filings to implement the SECA.[10] The Commission found that the SECA should be based on calendar year 2002 and 2003 data, adjusted for known and measureable differences and for hubbing transactions,[11] and developed on a subzonal basis.[12] The Commission also provided that, as part of the compliance filing process, load-serving entities could make shift-to-shipper claims,[13] and it allowed load-serving entities with existing transmission arrangements that continue into the transition period, and continue to pay regional through-and-out rates, to receive adjustments to their SECA obligations to prevent double recovery for such transmission.[14]

6. The Commission subsequently instituted settlement proceedings,[15] and the parties entered into a settlement, the Going Forward Principles and Procedures (Going Forward Principles),[16] which the Commission approved.[17] Among other things, the settlement delayed the elimination of rate pancaking until December 1, 2004 and committed the

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[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,212 (2003) (November 2003 Rehearing Order).

[11] For hubbing transactions, tag data show that the transaction sank in a particular zone, but the underlying transaction actually served load in another zone, either in the same RTO or outside of the RTO.

[12] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66, 80, 85.

[13] Shift-to-shipper claims allow load-serving entities under existing fixed-price contracts for bundled power supply 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 charges for that portion of the load-serving entity's load served by the contract.

[14] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45.

[15] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,105 (2004).

[16] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 63,024 (2004).

[17] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,262 (2004) (Going Forward Principles Order).

transmission owners to file pricing proposals under section 205 of the FPA. In its order on the two resultant pricing proposals,[18] the Commission, among other things, adopted license plate rates for the recovery of the cost of existing facilities and ordered compliance filings to incorporate the SECA as the transitional replacement rate effective December 1, 2004 through March 31, 2006.

7. In a series of orders, the Commission accepted and set for hearing initial and revised SECA implementation filings.[19] In the February 2005 Order the Commission established hearing procedures to review the charges applicable to PJM and Midwest ISO entities in order to recover SECA obligations due to Midwest ISO and PJM transmission owners respectively. Specifically, the Commission referred to hearing proposed revisions to PJM's and Midwest ISO's OATTs, implementing SECAs, effective December 1, 2004, to account for lost revenues claimed by Midwest ISO transmission owners for transactions sinking in PJM and for lost revenues claimed by PJM transmission owners for transactions sinking in Midwest ISO. Additionally PJM was directed to establish SECAs for intra-RTO lost revenue recovery for AEP, ComEd, and Dayton. The Commission directed the RTOs to provide supporting documents in developing the SECAs and parties were instructed to address the reasonableness of any proposed adjustments during the hearing.[20]

8. Prior to the hearing, the Presiding Judge issued the March 10 Partial Decision[21] and the April 13 Partial Decision[22] addressing motions for summary judgment. After the hearing, the Presiding Judge issued the Initial Decision.[23] Throughout the course of the

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[18] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168 (2004) (November 2004 Order).

[19] *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,107 (2005) (February 2005 Order); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,409 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 112 FERC ¶ 61,267 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,010 (2005).

[20] February 2005 Order, 110 FERC ¶ 61,107 at P 38.

[21] March 10 Partial Decision, 114 FERC ¶ 63,037.

[22] April 13 Partial Decision, 115 FERC ¶ 63,011.

[23] Initial Decision, 116 FERC ¶ 63,030.

hearing procedures, parties engaged in settlement discussions and some parties settled in whole or in part.[24]

A. March 10 Partial Decision, April 13 Partial Decision and Initial Decision

9. The Initial Decision found that the transmission owners failed to adequately support the claimed lost through-and-out revenues needed to calculate the SECA. It found that the transmission owners failed to carry their burden to make adjustments to test-period data for known and measurable differences and to remove hubbing transactions, but left the burden to propose and support such adjustments to customers. The Initial Decision also found that certain transmission owners' witnesses failed to independently verify data and that certain transmission owners did not sponsor witnesses that individually supported the transmission owners' level of lost revenues. For these reasons, the Initial Decision found that the claimed lost revenue amounts were invalid, and the transmission owners should be ordered to make new compliance filings that adequately supported their claimed lost revenue amounts.

10. Because the elimination of rate pancaking was delayed for eight months, from April 1 until December 1, 2004, by the Going Forward Principles settlement, the SECA was only charged for the last four months (December 2004 through March 2005) of the first year of the transition period. The Initial Decision found that the SECA for December 2004 through March 2005 should have been based on the corresponding calendar months of the test year. It also found that 2003 data should be used for the entire transition period because of certain anomalies and shortcomings in the quality of the 2002 data.

11. The Initial Decision found that, while an average rate method can be a legitimate way to allocate revenue responsibility, the use of an average rate to allocate lost revenues in the compliance filings aggravates cost shifting among the transmission owners. It found that certain PJM transmission owners' inclusion of revenues associated with in-out transactions (i.e., transactions where the tag shows that the transaction sank outside of the combined region) was not in compliance with the Commission's directives, which did not require the elimination of regional through-and-out rates for transactions that sink outside of the combined region nor the recovery of any associated lost revenues. It also rejected the inclusion of out-in revenues, which would increase SECA charges by including revenues associated with transactions that exited the combined region but then re-entered

[24] For a more detailed historical account of these proceedings, *see* Order on Initial Decision, 131 FERC ¶ 61,173. *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,174 (2010) (May 2010 Rehearing Order).

to sink within the region, finding that such adjustments were uncorroborated and would result in over recovery. In addition, it accepted hubbing adjustments proposed by parties for generation-only control areas, finding the adjustments to be correct and compliant with the Commission's previous orders.

12. The Initial Decision found that only revenues for the single regional through-and-out rate for transmission service between the two RTOs were to be included in the SECA mechanism. The Initial Decision found the inclusion of intra-RTO lost revenues in the SECA mechanism to be unjust and unreasonable.

13. In their compliance filings, transmission owners included revenues that they received from their merchant affiliates during the test period as lost revenues in their SECA calculations. The Initial Decision concluded that the inclusion of merchant affiliate transactions in the SECA calculations was unjust and unreasonable because it created a financial windfall for the utility and was contrary to the Commission's finding that the SECA was not intended to provide greater revenues for the utility. Therefore, the Initial Decision found that affiliate transactions should be excluded from the lost revenues upon which the SECA was calculated, and the lost revenues in the compliance filings should be recalculated in accordance with this conclusion.

14. While in prior orders adopting the SECA the Commission required that SECA charges be calculated on a subzonal basis in order to best reflect the relative benefits of individual customers due to the elimination of regional through-and-out rates, the Commission also recognized that North American Electric Reliability Corporation tag data could not be used to allocate lost revenues among subzones in the PJM market during the test period (Classic PJM)[25] because tags for imports into the PJM spot market were not associated with any particular load in PJM. The Commission directed the Classic PJM entities to propose an alternate method of allocating lost revenues among load in the PJM market in proportion to the benefits that the load realized due to the elimination of rate pancaking. The PJM transmission owners' compliance filings allocated lost revenues among entities in the Classic PJM market on a load-ratio basis (i.e., without attempting to determine the relative benefits that different loads will

[25] Classic PJM includes transmission owners that joined PJM on or before April 1, 2002, including: Allegheny Electric Cooperative, Inc.; West Penn Power Co., Monongahela Power Co., and The Potomac Edison Co. (collectively, Allegheny Power); Baltimore Gas and Electric Co.(BG&E); FirstEnergy Service Co. (FirstEnergy Service) and FirstEnergy Solutions Corp. (FirstEnergy Solutions) (collectively, FirstEnergy); PECO Energy Co.(PECO); Pepco Holdings, Inc. (Pepco); PPL Electric Utilities Corp. (PPL); Public Service Electric and Gas Co. (PSEG); Rockland Electric Co. (Rockland); and UGI Utilities, Inc. – Electric Division (UGI).

experience). The entities in the Classic PJM market stated that it was simply impossible to trace the benefits from imports to subzones in their area. The Initial Decision found that the record as developed did not support a finding that the use of subzones produces just and reasonable results. The Initial Decision found that the compliance filings' use of subzones in New PJM[26] but not in Classic PJM created unjust and preferential results between Classic PJM and New PJM and that the allocation in Classic PJM did not comply with cost-causation principles. In addition, the Initial Decision found that the record demonstrated that all of the proposed subzonal cost allocation filings failed to properly allocate charges consistent with cost-causation and benefit-derivation principles because the transmission owners had not considered the benefits that any particular subzone would expect to receive due to the elimination of regional through-and-out rates. Having found the proposed subzonal allocations to be unjust and unreasonable, the Initial Decision recommended instead using a combined zone or two separate zones, one for PJM and one for Midwest ISO.

15. The March 10 Partial Decision, April 13 Partial Decision, and Initial Decision ruled on a number of proposed adjustments to the test-period data for known and measurable differences. The Presiding Judge found that the SECA should be adjusted to remove revenues for contracts that were shown to have terminated prior to, or during, the transition period. The Presiding Judge also ordered that the SECA be adjusted to reflect reductions in load served by certain entities during the transition period compared to the test period.

16. The Initial Decision found that the Commission provided guidance that the SECA should be based on actual billing units, which is a type of usage charge. In the compliance filings, Midwest ISO transmission owners and the PJM transmission owners 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 would be a fixed demand-type charge, which is not based on current usage. The Initial Decision found that the proposed fixed charges were not in compliance with the Commission's orders and that the SECA rates should be developed in the traditional manner – by dividing test year revenues by test year load – and applied to actual monthly billing determinants for the transition period.

17. The Initial Decision rejected FirstEnergy's contention that existing transaction charges should be capped at the amount of a customer's SECA obligation, finding that the Commission has not held that such a cap should be employed. The Initial Decision

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[26] New PJM includes transmission owners that joined PJM after April 1, 2002, including: AEP, ComEd, Dayton, Virginia Electric and Power Co. (Dominion), and Duquesne Light Co.

stated that "[i]t is clear that the Commission only intended this mechanism to apply to [load-serving entities] with [existing transactions] which would pay [regional through-and-out] rates and SECA charges. The adjustment proposed would be to the SECAs and not to the [regional through-and-out rates] for [existing transactions]."[27]

18. The Initial Decision found that the bundled power supply contracts of Michigan South Central Power Agency (Michigan SCPA) and Six Michigan Cities[28] with Constellation Energy Commodities Group, Inc. (CCG) successfully demonstrated that CCG had taken responsibility under the fixed-price contracts to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, CCG should pay a portion of Michigan SCPA's and Six Michigan Cities' SECA obligations. In addressing CCG's "ripple" claim against AEP, the Initial Decision found that CCG successfully demonstrated that, under its fixed-price bundled supply contract with AEP, which CCG used to supply Michigan SCPA and Six Michigan Cities, AEP had taken responsibility to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, AEP should pay a portion of the SECA that Michigan SCPA and Six Michigan Cities shift to CCG. The Initial Decision also found that Quest Energy, LLC (Quest) demonstrated that, under its fixed-price bundled power supply contract with Mirant Americas Energy Marketing (MAEM), MAEM had taken responsibility to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, MAEM should pay a portion of Quest's SECA.

19. Finally, the Presiding Judge found that Green Mountain Energy Co. (Green Mountain) was appropriately assessed SECA charges under an unexecuted service agreement, which the Commission accepted in Docket No. ER05-1423-000, subject to the outcome of the hearing on the compliance filings. Green Mountain argued that it should not be assessed a SECA under the Midwest ISO tariff because it is not a transmission customer or market participant under the tariff. The Presiding Judge found that Schedule 22 of the Midwest ISO tariff, which provides for the recovery of the PJM transmission owners' lost revenues from entities within Midwest ISO, specifically provides for the collection of SECA charges from customers that may not be transmission customers or market participants as those terms are defined under the tariff. The Presiding Judge found that the record showed that Green Mountain is an entity that served load in Midwest ISO using transmission service under the Midwest ISO tariff that it had arranged through an affiliate, BP Energy Company (BP Energy).

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[27] Initial Decision, 116 FERC ¶ 63,030 at P 263.

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

B. Order on Initial Decision

20. In the Order on Initial Decision, the Commission disagreed with the Initial Decision as to the burden of proof. Specifically, the Commission found that the burden of proof concerning the lost revenue amounts was a shifting one: the onus was first on the transmission owners to provide and support their claimed lost revenue amount with information in their possession; once they had met that burden, the onus shifted to the transmission customers to provide and support adjustments to that data. Therefore, the Commission overturned the Initial Decision's rejection of the transmission owners' claimed lost revenues for failure to make adjustments for known and measurable changes and hubbing adjustments. The Commission also reversed the Initial Decision's finding that claimed lost revenue amounts were invalid because witnesses had failed to independently verify every data point used in determining the lost revenues and because certain transmission owners failed to sponsor witnesses that individually supported the transmission owners' level of lost revenues, as administrative proceedings do not impose such requirements. The Commission found that each calculation and input to the lost revenue amounts was supported with detailed testimony and exhibits that provide substantial evidence for the purpose of establishing just and reasonable SECA charges, and the fact that a transmission owner's lost revenue amounts incorporated calculations and data from several witnesses – even if the witnesses were presented on behalf of another company – did not indicate that the final calculation did not enjoy ultimate support.

21. The Commission found that the appropriate test-year periods for the first and second years of the transition period were calendar-years 2002 and 2003, respectively, as required in the Commission's orders adopting the SECA mechanism. Using two test periods smoothes out any irregularities to the extent that either year contains data abnormalities and the Commission does not require that the test period be of equal length to the period of effectiveness of the rates being tested.

22. The Commission found that the utilization of average rates when determining the SECA was consistent with the Commission's previous directives and was a practical means to determine the level of lost revenues that is just and reasonable. The Commission affirmed the Initial Decision's rejection of in-out transactions in the average rates of certain PJM transmission owners, finding that the SECA was not the appropriate vehicle for PJM transmission owners to recover lost revenues associated with the elimination of regional through-and-out rates for in-out transactions because PJM voluntarily eliminated rate pancaking for such transactions and was not directed to do so by the Commission in this proceeding. However, the Commission reversed the Initial Decision and accepted the inclusion of out-in transactions, finding it to be just and reasonable because such revenues could reasonably be expected to be lost due to the elimination of rate pancaking for transactions that sank within the region. The Commission also affirmed the Initial Decision's adoption of the proposed hubbing

adjustments for generation-only control areas and addressed other proposed hubbing adjustments raised on exception.

23. The Commission reversed the Initial Decision's finding limiting the SECA to inter-RTO lost revenue recovery. The Commission's prior orders provided for the recovery of certain intra-RTO lost revenues through the SECA, and the intra-RTO lost revenues included in the proposed SECA charges were compliant with these requirements.

24. The Commission found that the Initial Decision incorrectly found that affiliate transactions should be excluded from the SECA calculations. It explained that the revenue that a transmission owner receives from an affiliate for through-and-out transmission service is recorded as revenue for the transmission owner, just as if that revenue came from an unaffiliated entity, and is used to reduce the transmission costs to be born through the license plate rates from the transmission owner's local load. Thus, the inclusion of these revenues was necessary to prevent immediate cost shifting with the replacement of rate pancaking with license plate rates and to keep the transmission owners revenue neutral.

25. The Commission affirmed the proposed subzonal SECA charges, subject to specific adjustments. While the Commission previously determined that the SECA should be charged on a subzonal basis, the Initial Decision asserted that subzone allocations should be rejected because benefits to a subzone are not considered in creating the subzones. In the Order on Initial Decision, the Commission reversed the Initial Decision on this issue. It explained that using tag data to trace specific transactions during the test period, subject to adjustments for known and measurable differences, and using that information to create subzones did consider the benefits that accrued to loads in a subzone due to the elimination of regional through-and-out rates. The Commission also disagreed with the finding in the Initial Decision that using subzones produced unjust and preferential results between the Classic PJM and New PJM regions. Having subzones in the New PJM region but not in the Classic PJM region did not result in cost shifts between the two regions. Consistent with its previous findings, the Commission found based on the record that parties should use North American Electric Reliability Corporation tag data to calculate SECA charges to create subzones in Midwest ISO and New PJM notwithstanding the fact that such tag data cannot be used to create subzones in Classic PJM. The Commission also found that the proposal to allocate the SECA to load within the Classic PJM region on a load-ratio share basis was just and reasonable. While not as precise as using tag data to create zones or subzones, the SECA charges were still calculated based on transactions during the test period that can be traced to the Classic PJM area. The Commission found that no methodology would perfectly align those that benefit due to the elimination of regional through-and-out rates, and using North American Electric Reliability Corporation tag data where possible and a

load-ratio share where such tag data would not work was a reasonable compromise and one that was reasonably consistent with cost-causation principles.

26. The Commission reversed, in part, the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision with regard to the finding that contracts terminating prior to the transition period were not SECA eligible. However, the Commission affirmed the findings in the Initial Decision with respect to certain discrete claims that test-period load was not reflective of load served in the transition period and, thus, found that the SECA obligations should be adjusted accordingly. As the Commission explained, load-serving entities were assigned a SECA obligation based on test-period imports that utilized through-and-out service, unless such entities could demonstrate that known and measurable changes have occurred such that they do not benefit due to the elimination of rate pancaking. The Commission found that the fact that an entity's test-period contracts expired prior to the transition period and were not replaced with new contracts that cross the boundaries that were previously subject to rate pancaking is not dispositive as to whether the entity benefits due to the elimination of rate pancaking. Rather, as the Commission previously found, the elimination of rate pancaking will result in more remote generation becoming economic for import, which will put downward pressure on market prices where the importing load is located, resulting in lower costs for purchases from local generation as well as imports.

27. However, the Commission affirmed the findings in the Initial Decision, though under different reasoning, that certain parties' SECA obligations should be adjusted to reflect reductions in load served between the test period and the transition period. Unlike load-serving entities claiming that contracts terminated prior to the transition period and were, thus, not SECA eligible, adjustments to SECA obligations were appropriate for load-serving entities with reduced load during the transition period to accurately align the benefits realized due to the elimination of regional through-and-out rates to the level of load served during the transition period. Where the load served by the load-serving entity during the transition period had been reduced since the test period, or was no longer served by the load-serving entity during the transition period, it was reasonable to conclude that the load-serving entity would not benefit due to the elimination of regional through-and-out rates for the load no longer served.

28. The Commission reversed the Initial Decision's rejection of the fixed subzonal SECA charges proposed in the compliance filings. While the Initial Decision was correct that the SECA adopted by the Commission was designed as a usage charge, the transmission owners in each RTO have voluntarily designed their subzonal SECA charges as fixed charges that recover test-period revenues and did not vary with the level of the load-serving entity's load. While the Initial Decision found that such fixed charges resulted in unjust and unreasonable charges for certain entities that had experienced reductions in the loads that they serve since the test period, the Commission instead ordered adjustments to the subzonal SECA charges for those entities to reflect their load

reductions, rather than order changes to all of the non-settled SECA charges to reflect a traditional usage charge, which would generally result in increased charges for customers.

29. The Commission affirmed the Initial Decision's finding that FirstEnergy's SECA obligation should not serve as a cap for through-and-out charges associated with existing transactions (i.e., reservations for requests for service made prior to November 17, 2003, for service commencing before April 1, 2004). The Commission agreed that FirstEnergy was not entitled to a refund for the amount that FirstEnergy's through-and-out charges for existing transactions exceeded its SECA obligations under the Commission's prior orders, nor was such a refund necessary to ensure that transmission owners did not double recover their revenue requirements.

30. The Commission affirmed the Initial Decision's findings that Michigan SCPA and Six Michigan Cities successfully demonstrated that CCG should pay a portion of Michigan SCPA's and Six Michigan Cities' SECA obligations. However, the Commission reversed the Initial Decision as to the exact portion of one entity's SECA obligation that should be shifted to CCG. The Commission reversed the Initial Decision as to CCG's "ripple" claim against AEP because the Commission's prior orders did not provide for "ripple" claims. The Commission also reversed the Initial Decision's finding that a contract existed between Quest and MAEM and that, therefore, MAEM should pay a portion of Quest's SECA.

31. Finally, the Commission reversed the Presiding Judge's finding that Green Mountain was appropriately assessed SECA charges under an unexecuted service agreement even though Green Mountain was not a transmission customer or market participant under the Midwest ISO tariff. Instead, the Commission found that BP Energy, Green Mountain's affiliate that directly contracted with Midwest ISO on Green Mountain's behalf during the transition period, should pay Green Mountain's SECA obligation.

32. In addition, the Commission approved three settlements that were certified to the Commission as contested during the hearing. The Commission found that two of the settlements were no longer contested and that the objections to the third settlement were outside of the scope of the settlement and were addressed in the May 2010 Rehearing Order.

II. Requests for Rehearing

33. Requests for clarification and/or rehearing of the Order on Initial Decision were filed by: AEP,[29] Dayton, and Exelon Corporation (Exelon);[30] American Municipal Power, Inc. (AMP);[31] BG&E; BP Energy; CCG and Constellation NewEnergy, Inc. (collectively, Constellation); Direct Energy, LLC (Direct Energy),[32] Integrys Energy Services, Inc. (Integrys), and Quest; Dominion; Green Mountain; and Ormet Primary Aluminum Corporation (Ormet). Ormet filed a late amendment to its rehearing request.

34. Green Mountain, CMS Energy Resources Management Company (CMS Energy), Mirant Corporation, FirstEnergy,[33] BP Energy, Integrys, Quest, AEP, Dayton and Exelon filed answers. Quest and Integrys subsequently filed a motion requesting the Commission expeditiously issue an order on rehearing.

III. Discussion

35. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2011), prohibits answers to requests for rehearing, and therefore, we will reject the answers and replies.

A. Sponsorship/Support for Level of Lost Revenues

36. While the Initial Decision rejected most claims by transmission owners concerning their level of lost revenues, finding that they failed to adequately support their claims, the Order on Initial Decision largely reversed the Initial Decision on this issue. Specific Commission determinations in dispute, and relevant rehearing requests, are discussed below.

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[29] AEP submitted the filing on behalf of: Appalachian Power Service Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co.

[30] Exelon submitted the filing on behalf of: ComEd and PECO.

[31] AMP was formerly known as American Municipal Power – Ohio, Inc. AMP submitted the filing on behalf of itself and its members.

[32] Direct Energy has acquired Strategic Energy, LLC.

[33] FirstEnergy Services submitted the filing on behalf of itself and Cleveland Electric Illuminating Co., Ohio Edison Co., Toledo Edison Co., and FirstEnergy Solutions.

1. Burden of Proof

a. Order on Initial Decision

37. The Order on Initial Decision reversed the Initial Decision's determination that the burden was solely on transmission owners to adjust their lost revenue claims to reflect hubbing transactions and known and measurable changes and that they failed to meet that burden. As stated in the Order on Initial Decision:[34]

> While sections 205 and 206 of the FPA, as well as the Administrative Procedure Act, place the burden on the moving party, a responding party has a burden of its own; a responding party must provide more than unsubstantiated claims. Thus, as relevant here, the burden of proof concerning the lost revenue amounts at issue is a shifting burden: the onus is first on the transmission owners to provide and support their claimed lost revenue amounts with information in their possession; once they have met that burden, the onus shifts to the transmission customers to provide and support the adjustments that they advocate. This is consistent with the fact that transmission owners possess historical base-period data, while transmission customers are likely to possess information necessary to make adjustments based on data that transmission owners are not likely to possess. This determination is also consistent with prior Commission orders in this case that discussed the role of transmission customers in developing SECA rates. Thus, where a transmission owner properly demonstrates a claimed lost revenue amount, the amount should be considered uncontroverted unless a transmission customer, in turn, properly demonstrates a required adjustment. Accordingly, the Initial Decision errs to the extent that it places the burden of showing known and measurable changes squarely on the transmission owners.[[35]]

b. Requests for Rehearing

38. BG&E and Constellation assert that the Order on Initial Decision inappropriately placed the burden of proving hubbing adjustments and known and measurable differences on non-jurisdictional retail load and essentially relieved transmission owners of any

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[34] Order on Initial Decision, 131 FERC ¶ 61,173 at P 93.

[35] The Order on Initial Decision further ordered specific adjustments to the claimed lost revenue amounts and SECA charges for hubbing transactions and known and measurable changes that had been properly supported.

burden of proof by presuming that their claimed lost revenues amounts were valid absent evidence to the contrary.[36] BG&E and Constellation contend that the Order on Initial Decision represents an arbitrary and capricious reversal of a prior Commission directive that, according to them, placed the burden of proof squarely and solely on transmission owners.[37] Indeed, Constellation claims that the Order on Initial Decision shifted the burden of proof to transmission customers only after the evidentiary hearing and issuance of the Initial Decision and, thereby, violated the due process rights of load-serving entities.[38] Moreover, Constellation argues that, because it was transmission owners, not transmission customers, who were required to make SECA compliance filings, the burden of proof logically and entirely rested with them.[39]

c. Commission Determination

39. We will deny requests for rehearing as to the burden of proof. Contrary to BG&E's and Constellation's arguments, the Order on Initial Decision's finding that transmission owners and transmission customers share a shifting burden of proof is consistent with prior Commission orders in this case. The Commission has stated throughout this proceeding that transmission customers are responsible for supporting adjustments to transmission owners' claimed lost revenues. For example, as noted in the Initial Decision,[40] in the November 2003 Rehearing Order, the Commission stated that

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[36] BG&E Request for Rehearing at 23; Constellation Request for Rehearing at 28.

[37] BG&E Request for Rehearing at 26-27 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 80 ("We . . . order the parties to make adjustments to the [North American Electric Reliability Corporation] tag data submitted in the compliance filings . . . to remove . . . 'hubbing' transactions."); Constellation Request for Rehearing at 29 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 97 ("Midwest ISO and PJM are directed to file compliance filings to change the rate design by eliminating the [regional through-and-out rates] for transactions sinking in the combined region and implementing lost recovery mechanisms . . . .")).

[38] Constellation Request for Rehearing at 31.

[39] *Id.* at 29. Constellation claims that its position is further supported by stated Commission expectations that Midwest ISO and PJM consult with the parties and that "the parties in the region . . . . work cooperatively in the preparation of these filings [and] resolve issues before the filings are made." *Id.* at 29-30 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 97).

[40] Order on Initial Decision, 131 FERC ¶ 61,173 at P 93, n.80.

"customers [with hubbing transactions] will have the opportunity to show in the implementation stage that transactions tagged as sinking in their zones actually sink in another zone or RTO…."[41] In addition, in the February 2005 Order, the Commission stated that the reasonableness of *customers'* proposed adjustments to SECA rates should be addressed at hearing.[42] Accordingly, transmission customers have been on notice since at least the hearing stage that the onus is on them to propose adjustments to lost revenue claims.

40. Commission statements to the effect that the parties should work together to fix lost revenue amounts prior to such amounts being submitted for approval only recognize that transmission customers are in possession of data concerning known and measurable differences and hubbing transactions and should bring any such adjustments to light, and the most efficient way for transmission customers to satisfy such a burden is to do so in the early stages of litigation.[43] Moreover, while BG&E and Constellation would have transmission owners scout for information not in their possession and then be faulted for failing to discover it, it would be unfair to allow those in possession of the information to withhold it (or not readily disclose it) and then prevail on a claim that the information was not used. Instead, we find that, once transmission owners adequately supported their claimed lost revenues (which is an evidentiary question that the Commission addressed in the Order on Initial Decision and we further discuss below), the onus is on transmission customers to come forward with the information in their possession that supports adjustments to the claimed lost revenue amounts. Accordingly, we here affirm the Order on Initial Decision's determinations concerning the burden of proof and, most specifically, that the onus was on transmission customers, not transmission owners, to support adjustments for known and measurable differences and hubbing transactions.

2. Hearsay Claims

a. Order on Initial Decision

41. While the Initial Decision rejected Midwest ISO transmission owners' lost revenue calculations based upon the finding that the calculations incorporated hearsay

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[41] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 96.

[42] February 2005 Order, 110 FERC ¶ 61,107 at P 38.

[43] An analogous concept exists in the context of civil litigation, whereby a plaintiff and defendant may submit a joint stipulation of facts without relieving either party of its evidentiary burdens.

evidence (i.e., data not independently verified by their sponsoring witness),[44] the Order on Initial Decision reversed that finding, explaining that administrative hearings need not exclude hearsay evidence that is otherwise substantial and has probative value.[45] The Order on Initial Decision further stated that, per Rule 509(a) of the Commission's Rules of Practice and Procedure, the basic test as to the admissibility of evidence is whether the evidence is of the "kind that would affect reasonable and fair minded persons in the conduct of their daily affairs."[46] Moreover, the Order on Initial Decision noted that the Initial Decision's rejection of hearsay evidence proffered by Midwest ISO transmission owners was inconsistent with the Initial Decision's acceptance of data provided by other transmission owners.[47]

42. The Order on Initial Decision found that Midwest ISO transmission owners' witness, Mr. Heintz, provided substantial evidence having probative value and of the kind that would affect reasonable and fair minded persons in the conduct of their daily affairs. The Order on Initial Decision noted that the Initial Decision lauded Mr. Heintz for providing "detailed testimony and exhibits" and showing a thorough knowledge of the case and the proposed SECA methodology, even under cross-examination.[48] The Order on Initial Decision reiterated that, while Mr. Heintz might not have independently

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[44] The Federal Rules of Evidence's hearsay rule, as applied in a hearing in a Federal district court, generally speaking prohibits the admission of a statement, other than one made by the declarant while testifying at the trial or hearing, offered in evidence to prove the truth of the matter asserted therein. Fed. R. Evid. 801(c). The Initial Decision rejected certain calculations provided by Mr. Heintz, based upon the Initial Decision's finding that he relied upon hearsay (i.e., through-and-out revenue amounts provided to him by Midwest ISO and Midwest ISO transmission owners, without independently verifying the amounts himself). Initial Decision, 116 FERC ¶ 63,030 at P 114-16.

[45] Order on Initial Decision, 131 FERC ¶ 61,173 at P 97 (citing *Mont. Power Co. v. FPA*, 185 F.2d 491, 498 (D.C. Cir. 1950); *Johnson v. United States*, 62 F.3d 187, 190 (D.C. Cir. 1980)).

[46] *Id.* P 97 (citing 18 C.F.R. § 385.509(a) (2010)).

[47] *Id.* P 96.

[48] *Id.* P 98 (citing Initial Decision, 116 FERC ¶ 63,030 at P 114).

verified every data point used in determining Midwest ISO transmission owners' lost revenues, administrative proceedings do not impose such a requirement.[49]

b. Requests for Rehearing

43. BG&E and Constellation assert that the Commission's reversal of the Initial Decision's findings on this issue was arbitrary and capricious. BG&E argues that the Commission's determination concerning hearsay evidence inappropriately requires proof of inaccurate data (from transmission customers), rather than independent verification of accurate data (by transmission owners).[50] Noting the Commission's statement that the "critical question is whether the underlying data is relevant and its accuracy is supported" (made with regard to whether a Midwest ISO transmission owners' witness sponsored certain of their lost revenue claims), Constellation asserts that the Presiding Judge, rather than the Commission, was in the best position to make such determinations.[51]

c. Commission Determination

44. We will deny rehearing on this issue for all of the reasons set forth in the Order on Initial Decision. BG&E's and Constellation's arguments against the adequacy of hearsay evidence fail to overcome the general principle that administrative hearings are not bound by the Federal Rules of Evidence, where the evidence at issue is otherwise substantial and has probative value. We reiterate: the basic test as to the admissibility of evidence is whether the evidence is of the "kind that would affect reasonable and fair minded persons in the conduct of their daily affairs."[52] Accordingly, evidence should not be excluded from administrative proceedings based solely on its characterization as hearsay, and with regard to the testimony submitted by Mr. Heintz, the Initial Decision did just that. Having found that Mr. Heintz' testimony otherwise satisfied the Commission's regulations for admissibility – a finding supported by the Initial Decision itself[53] – the

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[49] *Id.* P 98.

[50] BG&E Request for Rehearing at 31.

[51] Constellation Request for Rehearing at 32 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 100).

[52] 18 C.F.R. § 385.509(a) (2010).

[53] As noted above, the Initial Decision, 116 FERC ¶ 63,030 at P 114, found that Mr. Heintz provided "detailed testimony and exhibits" and showed a thorough knowledge of the case and the proposed SECA methodology, even under cross-examination.

Order on Initial Decision determined that the evidence should not be excluded for hearsay reasons alone,[54] and we affirm that determination here.

3. Witness Sponsorship

a. Order on Initial Decision

45. The Order on Initial Decision reversed the Initial Decision's finding that no witnesses sponsored Classic PJM TOs'[55] (as well as PECO's, and Dayton's) lost revenue claims. As stated in the Order on Initial Decision:

> The Commission's review of the record reveals that, for each of these companies, a witness supported each element of the final, claimed lost revenue amounts. We agree with Classic PJM TOs that the fact that a calculation incorporates data from several witnesses – even if the witnesses were presented on behalf of another company – does not indicate that the final calculation enjoys no ultimate support. The critical question is whether the underlying data is relevant and its accuracy is supported. As to Classic PJM TOs, nothing in the testimony of one witness contraindicates the relevancy and accuracy of data from another witness. As both Classic PJM TOs and PECO note, they properly relied upon Mr. Dessender, Manager, Markets Settlement for PJM, to verify the revenues received by PJM for through-and-out transmission service provided in 2002 and 2003. As a PJM employee, he was not expected to support lost revenues for the individual transmission owners; Mr. Bustard and Dr. Henderson collectively provided such support for Classic PJM TOs and PECO.[[56]]

b. Request for Rehearing

46. Putting aside general arguments concerning the shifting burden of proof, discussed above, AMP asserts that, substantively, BG&E failed to satisfy even an initial burden of proof to support its claimed lost revenue amount. As stated from AMP's viewpoint, BG&E's lost revenue claim (as originally asserted along with Classic PJM TOs' lost revenue claims) suffers from the following infirmities. First, BG&E's claim inappropriately conflates revenues generated by regional through-and-out rates with lost

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[54] Order on Initial Decision, 131 FERC ¶ 61,173 at P 98.

[55] *Id.* P 101.

[56] Order on Initial Decision, 131 FERC ¶ 61,173 at P 100.

revenues.[57] On this point, AMP argues that, once regional through-and-out revenues have been calculated, several adjustments should be made, including for grandfathered transactions, known and measurable changes and transactions that exited the combined region.[58] Second, the claim contains significant and acknowledged errors.[59] On this point, AMP disputes both the average rate used as a measure of compensation owed to BG&E and the validity of the SECA charges designed to recover lost revenues on behalf of Classic PJM TOs due to the addition of Dominion to PJM.[60] Third, BG&E's claim was not calculated by a single, specific witness, but rather was pieced together from the testimony of several witnesses supporting various aspects of Classic PJM TOs' regional through-and-out rate calculations.[61] On this point, AMP argues that there is a dearth of record evidence showing that for Classic PJM TOs, and more specifically BG&E, a specific witness accurately calculated regional through-and-out rates, made appropriate adjustments, and developed the lost revenue claim.[62]

c. Commission Determination

47. We will deny AMP's request for rehearing on this issue. While AMP argues that BG&E inappropriately conflated regional through-and-out rates with actual lost revenues, it is AMP that attempts to draw a distinction without a difference. Revenues generated by regional through-and-out rates, adjusted for grandfathered transactions and schedules that the tag data show exited the combined region, are indeed the starting point for final lost revenue claims; but the adjustments to such revenues that AMP seeks to make, such as for known and measurable differences and hubbing transactions, are, as stated in the Order on Initial Decision and reiterated above, the responsibility of transmission

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[57] AMP asserts that lost revenues equate to the amount of through-and-out revenue lost by transmission owners due to elimination of most regional through-and-out rates as of December 1, 2004 and should be derived by first calculating accurate regional through-and-out revenues and then subtracting revenues not actually lost as a result of Commission orders eliminating the collection of regional through-and-out rates on the majority of cross-border transactions. AMP Request for Rehearing at 16.

[58] *Id.* at 17.

[59] *Id* at 19.

[60] *Id.*

[61] *Id.* at 14.

[62] *Id.* at 23.

customers. Where a transmission owner properly supports its revenues generated by regional through-and-out rates, adjusted for grandfathered transactions and schedules that the tag data show exited the combined region, as BG&E did,[63] the calculation may become its final lost revenue claim absent properly supported downward adjustments, as set forth by a transmission customer, for known and measurable differences and hubbing transactions. While AMP generally asserts that BG&E's lost revenue claim requires modification, it fails to state exactly which adjustments, other than errors that have already been identified and corrected, are necessary and why.

48. As to AMP's arguments concerning the various data inputs and witness support related to BG&E's lost revenue calculation, we find that AMP has raised no arguments on rehearing that were not already fully addressed at an earlier stage in this proceeding, including in the Order on Initial Decision.[64] Although AMP reiterates arguments assailing the calculation of Classic PJM TOs' SECA rates (which includes BG&E's rate), simply reiterating those arguments does not make them more persuasive. The Order on Initial Decision found that the Classic PJM TOs, including BG&E, properly supported their lost revenue claims,[65] and AMP's arguments on this point – which AMP has previously asserted and the Commission has already considered – are unconvincing.

49. In addition, as set forth in the Order on Initial Decision and noted above, the Commission has not required that each transmission owner offer a single, specific witness to sponsor its lost revenue claim. Neither statute nor Commission regulations require that a single witness prove a claim; rather the evidence presented, whether piecemeal by multiple witnesses or entirely by a single witness, is viewed in its totality in determining whether the claim is sufficiently supported. Finally, to the extent that AMP believes that a single, specific witness must independently verify every input into a lost revenue claim in order to avoid the use of hearsay evidence, those arguments were also addressed, and rejected, in the Order on Initial Decision and above.

B. Test Period

1. Order on Initial Decision

50. The Order on Initial Decision reversed the Initial Decision's findings that calendar-year 2003 data should be used for the entire transition period and that, in the

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[63] Dessender Test., Ex. No. CTO-1.

[64] Order on Initial Decision, 131 FERC ¶ 61,173 at P 100.

[65] *Id.*

alternative, the 2002 test-year data should reflect the same months as were reflected in the transition period (i.e., December and January through March). In the Order on Initial Decision, the Commission found that the appropriate test year periods for the first and second years of the transition period are calendar-years 2002 and 2003, respectively. In the November 2003 Rehearing Order, the Commission balanced the interest of using the most recent data with the interest of using data that made filings that could be placed into effect for the first year of the transition period feasible. The Commission found that the use of 2002 data for the first year of the transition period remained necessary for administrative convenience when the filings were due on November 24, 2004, given that the transmission owners and other parties were engaged in intensive negotiations to develop alternative long-term pricing solutions for filing by October 1, 2004. In addition, the Commission found that using two test periods smoothes out any irregularities to the extent that either year contains data abnormalities, whereas the alternative proposal to use 2003 data for the entire transition period could fail to adjust for such abnormalities. Further, the Commission noted that it does not require that the test period be of equal length to the period of effectiveness of the rates being tested.[66]

2. Requests for Rehearing

51. AMP argues that the Commission failed to substantively address evidence submitted by AMP showing that the use of an entire year's data (i.e., 2002) for the four-month period comprising the first year of the transition period resulted in data anomalies being reflected in the resultant SECA charges and did not appropriately account for seasonal discrepancies. According to AMP, using only the winter months of 2002 as the test period for the first year of the transition period would ensure that transmission owners are not over-compensated. AMP further asserts that, because regional through-and-out rates were not eliminated until December 2004, the transmission owners recovered regional through-and-out rates for the high-usage summer months of 2004.[67]

52. AMP argues that, by basing the SECA charges for the initial portion of the transition period on data that include the peak summer months during 2002 – months in which loads and thus transmission volumes would be relatively high and the discounting of rates especially scarce – the transmission owners failed to reflect the expected use of the transmission system during the first four months of the transition period. AMP states that it had schedules crossing the Midwest ISO-PJM seam that were summer-only schedules, arranged by AMP to meet the summer peaks of its members. AMP states that these schedules do not exist during the winter months of December through March.

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[66] Order on Initial Decision, 131 FERC ¶ 61,173 at P 115.

[67] AMP Request for Rehearing at 28-29.

During the peak summer months, energy usage and transmission volumes are relatively high, whereas during off-peak months, load is much lower.[68]

53. AMP contends that, because its summer-only schedules and high loads were included in the lost revenues calculations for the first four months of the transition period, the claimed lost revenues that the transmission owners experienced during these months and the SECA charges were overstated. According to AMP, the transmission owners could not have experienced lost revenues associated with summer-only schedules during 2004 because they continued to collect regional through-and-out rates through November of that year. Therefore, AMP argues that the SECA calculations should exclude the summer schedules from the 2002 test year.[69]

54. With respect to the Commission's rationale that it does not require that the test period be of equal length to the period of effectiveness of the rates being tested, AMP argues that this may be true in typical rate proceedings, in which rates are set for a prospective, open-ended period of time, but not for SECA charges during a discrete, four-month period as is the first year of the transition period. AMP argues that, because it is known that the rates will be in effect for only four months, and when it is known that the transmission amounts and patterns for those winter months are not the same as for the average month, and when it is known that load-serving entities will be charged in the winter months on the basis of their transmission in the test period, compliance with the Commission's directive to "approximate the expected use of the exporting utility's transmission system" demands that the test period be limited to the same four-month period.[70] AMP argues that legitimate challenges to the test period must be resolved on the basis of the record, not on the basis of what is missing from the Commission's filing requirements.[71] Constellation argues that the mere fact that the Commission does not require the test period to be of equal length to the transition period does not address whether the use of calendar-year 2002 data led to the over-collection of lost revenues by the transmission owners.[72]

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[68] *Id*. at 29-30.

[69] *Id.* at 30.

[70] *Id.* at 31 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 48).

[71] *Id.* at 32.

[72] Constellation Request for Rehearing at 43.

55. Constellation and AMP also dispute the Commission's rationale concerning administrative convenience, citing the testimony of Mr. Henderson that it "would be a straightforward matter" to change the 2002 test period to four months.[73] AMP further states that it is unclear why it would have been more difficult to calculate lost revenues for a four-month period than for a twelve-month period.[74]

56. Ormet argues that section 35.13(d)(3)(i) of the Commission's regulations and traditional ratemaking principles require use of the most recent data in calculating rate formulas. It contends that a test period of 2003 for all sixteen months of the transition period is consistent with this requirement.[75] Ormet also disputes the Commission's rationale that using both 2002 and 2003 data for the test period smoothes out any irregularities to the extent that either year contains data abnormalities. Ormet argues that 2002 was an aberrational year and is a less accurate predictor of trading patterns in 2004 and 2005 than is calendar year 2003. It contends that the 2002 historical data contains numerous, significant anomalies that cannot be adequately "smoothed" by 2003 data and warrant their exclusion from the test period. Ormet points to: (1) several major events occurred in both Midwest ISO and PJM in 2002 that dramatically adjusted trading patterns going forward;[76] (2) in 2002, PJM had an abnormally high proposed revenue recovery; and (3) the 2002 test-year data includes atypical activity for various utilities.[77]

57. Ormet also argues that equitable considerations support the use of 2003 as the test period for the entire transition period. Ormet contends that the use of 2003 test-period data would: (1) more accurately reflect future trading patterns; (2) more accurately match lost revenues collected from loads with the benefits that loads will receive due to the elimination of regional through-and-out rates; (3) use more accurate data requiring

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[73] *See, e.g., id.* at 43-44 (citing Henderson Rebuttal Test., Ex. No. PTO-81 at 43:22).

[74] AMP Request for Rehearing at 32.

[75] Ormet Request for Rehearing at 11-12.

[76] For example, Ormet notes, Midwest ISO began operations in February 2002, and during that year the market had to adjust to Midwest ISO's role as a transmission provider as Midwest ISO resolved transmission rate discounting and available transfer capability calculation issues. Also, Allegheny Power joined PJM in 2002, further altering trading patterns from flows through Dominion to PJM to flows through Allegheny Power to PJM and requiring accounting adjustments for out-in transactions.

[77] Ormet Request for Rehearing at 12-13.

fewer adjustments, including adjustments for known and measurable differences; (4) use one test period, rather than two, for the transition period; (5) allow Midwest ISO and PJM to more accurately recover lost revenues attributable to the elimination of regional through-and-out rates; and (6) capture load that might have been grandfathered in 2002 but was subject to the Open Access Transmission Tariff during the 2003 test period.[78]

3. Commission Determination

58. We will deny the rehearing requests of AMP, Constellation, and Ormet on this issue. With respect to AMP's argument concerning the potential for over- recovery of regional through-and-out charges, we are not persuaded. AMP may be correct that transmission owners recovered more during the summer months of 2004 through continuation of the regional through-and-out rates than they would have had the SECA replaced the regional through-and-out rates during that period, and as a result recovered more during the twelve-month period (April 1, 2004 through March 31, 2005) that was to be the first year of the of the two-year transition period originally adopted before the Going Forward Principles settlement. However, this does not mean that the transmission owners have over-recovered or double recovered regional through-and-out charges. The problem with AMP's logic is that it focuses on the April 1, 2004 through March 31, 2005 period, during part of which regional through-and-out rates were in effect and during part of which the SECA replacement rate was in effect. However, focus on that particular twelve-month period to evaluate the impact of this one-time change in rate design is arbitrary because customers did not take through-and-out service only for the two, discreet one-year periods corresponding to the originally-adopted transition period for the SECA, but instead took service before, during, and after that period, and such service did not necessarily commence or terminate on April 1 or March 31, or any other day, of a particular year. What is important is that the rates are designed to allow an opportunity to recover the transmission owners' annual revenue requirements, no more and no less. If one looks instead at the twelve-month period ending November 30, 2004, during which regional through-and-out rates remained continuously in effect, and the twelve-month period ending November 20, 2005, during which the SECA was continuously in effect, there is clearly no over-recovery, because under each rate design, rates were designed to provide an opportunity to recover the transmission owners' annual revenue requirement over the course of a twelve-month period.[79]

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[78] *Id*. at 14-15.

[79] We further note that both the regional through-and-out rates (for existing transactions) and the SECA were eliminated on April 1, 2006, prior to the 2006 peak summer season.

59. We are also not persuaded by arguments disputing the Order on Initial Decision's reliance on the fact that the Commission's regulations for FPA section 205 filings do not require the test period and transition period to be of equal length. The Order on Initial Decision was simply acknowledging a long-established provision of the Commission's regulations, relying on the use of calendar-year data.[80] Further, the discussion in the November 2003 Rehearing Order that AMP cites with respect to the Commission's directive to approximate the expected use of the exporting utility's transmission system did not hold that the test period and the transition period must be of the same length.[81]

60. In addition, the Order on Initial Decision did not merely find that it was convenient for the applicants to use calendar-year 2002 data for the first year of the transition period because the Commission wanted to avoid creating extra work for the transmission owners. Rather, the Commission determined that it was "*necessary* for administrative convenience" (emphasis added), because of the nearness of the due date for the filings as well as the intensive negotiations between the transmission owners and other parties to develop alternative, long-term pricing solutions.[82]

61. We disagree with arguments that anomalies in the calendar-year 2002 data are too significant to be smoothed out by the inclusion of calendar-year 2003 data. No one year is perfectly identical to another. We do not consider any differences between 2002 and the years the rate is charged sufficient to warrant our entirely ignoring 2002. We do not, for example, consider the market's adjustment to the role of Midwest ISO as transmission provider or the fact that a utility joined PJM to constitute such significant data abnormalities that they cannot be smoothed out by the calendar-year 2003 data.

62. We also provided opportunity at hearing to adjust SECA charges for known and measurable changes, to the extent that test-year data is not representative of the benefits that customers would experience due to the elimination of rate pancaking during the transition period, and adopted a number of such adjustments proposed through the hearing. Finally, to the extent that Ormet seeks use of 2003 data instead of 2002 data. Ormet's argument is an improper collateral attack on the November 2003 Rehearing Order in which the Commission found that the SECA rates should be based on calendar year 2002 and calendar year 2003 data.[83] Ormet had the opportunity to challenge the use

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[80] Order on Initial Decision, 131 FERC ¶ 61,173 at P 115.

[81] AMP Request for Rehearing at 31 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 48).

[82] Order on Initial Decision, 131 FERC ¶ 61,173 at P 115.

[83] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66.

of test-period data, and failed to do so, as other parties did. The Commission rejected these challenges in the May 2010 Rehearing Order and will not relitigate them here.[84]

C. Method for Determining Level of Lost Revenues

1. Order on Initial Decision

63. The Order on Initial Decision reversed the Initial Decision and found the utilization of average rates to be consistent with the Commission's previous directives and appropriate because the Commission had previously rejected the alternative use of actual test-period usage and invoices.[85] The Order on Initial Decision noted that the increased number of transactions involving power marketers that do not have detailed bills would make a more direct calculation of transmission charges almost impossible.[86] The Commission also rejected arguments that the use of average rates would inappropriately shift costs from parties with low load factors to parties with high ones (i.e., from parties that use less of their reserved transmission capacity to parties that use relatively more). We found that accounting for load factor utilization differences would be impractical due to power marketing arrangements and the redirection of reservations to alternate sinks. We stated that delivered energy may be better than reserved transmission capacity at indicating the relative benefits of the elimination of regional through-and-out rates, which would justify allocating lost revenues to parties with relatively high load factors.[87]

64. The Order on Initial Decision agreed with the Initial's Decision's finding that Dr. Henderson's use of in-out transactions (i.e., transactions where the tag shows that the transaction sank outside of the combined region) when determining average rates was unjust and unreasonable. The Order on Initial Decision directed the PJM transmission owners to remove the associated revenues from the average rate. The Commission explained that it was not obligated to establish a lost revenue recovery mechanism because PJM voluntarily eliminated such regional through-and-out rates. Rather the Commission found that including in-out transactions in the numerator, but not the

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[84] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 170-171.

[85] *Id.* P 150 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 64 n.117, 67).

[86] *Id.* (citing Heintz Test., Ex. No. MTO-1 at 23:17-24:3).

[87] *Id.* P 151.

denominator, of the average rate determination would inflate the average rate and unfairly shift costs to load-serving entities.[88]

65. Finally, the Order on Initial Decision denied Dominion's request and did not require AEP to recalculate its lost revenues to reflect a Stipulation and Agreement that was previously accepted by the Commission in Docket No. ER05-751-000. The Commission did not require transmission owners to file updated rates in order to justify their level of SECA charges and found that Dominion made no showing that the existing rates and revenues that form the basis of the SECA are no longer just and reasonable.[89]

2. Requests for Rehearing

66. Constellation and Green Mountain contend that the Commission erred in accepting the use of average rates. Green Mountain argues that the Commission's rationale for approving the use of average rates consists "entirely of recitations of the weaknesses of other potential methods."[90] It maintains that the unreasonableness of alternative rate designs does not establish the justness and reasonableness of using average rates. Green Mountain asserts that the Commission has admitted that the use of average rates shifts costs from entities with low load factors to entities with high load factors.[91] Constellation claims that the average rate calculations use reserved transmission capacity in the numerator and delivered energy in the denominator, which imposes excessive SECA charges on customers with high load factors contrary to cost-causation principles.[92] Constellation concludes that the SECA is unduly discriminatory and preferential in violation of sections 205 and 206 of the FPA.

67. AEP, Dayton, and Exelon argue that the Commission erred in finding that in-out revenues should be removed from the numerators of the average rate calculation for AEP, ComEd, and Dayton. By doing so, they contend that the Commission has failed in its commitment to hold the PJM transmission owners revenue neutral.[93] AEP, Dayton, and

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[88] *Id.* P 152.

[89] *Id.* P 162.

[90] Green Mountain Request for Rehearing at 11 n.32.

[91] *Id.* at 11 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 151).

[92] Constellation Request for Rehearing at 34-35.

[93] AEP, Dayton, and Exelon Request for Rehearing at 5 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 46-47; May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 101).

Exelon maintain that they lost revenues as a result of the elimination of through-and-out rates, claiming that whether PJM could have assessed its through-and-out rate on in-out transactions is not germane. They assert that PJM did not understand that the Commission intended to maintain rate pancaking for in-out transactions, and thus, PJM eliminated its through-and-out rates for all transactions going to Midwest ISO, regardless of the sink. AEP, Dayton, and Exelon add that the PJM system was not designed to identify sinks for through-and-out deliveries and would have had to rely upon market participants to properly identify sinks in their transmission service requests.[94] They also argue that, if PJM had attempted to charge its through-and-out rates for in-out transactions, it is unlikely that PJM would have continued to collect comparable amounts of through-and-out revenues because market participants would structure their transactions to avoid paying the rate. Given that there has never been a mechanism to recover lost revenues associated with in-out transactions except under the SECA rate design and that loads within the combined region experience general benefits due to the elimination of through-and-out rates, AEP, Dayton, and Exelon maintain that including in-out revenues in their lost revenue calculations would be consistent with cost-causation principles.

68. If the Commission does not grant rehearing to permit the inclusion of in-out revenues, AEP, Dayton, and Exelon request that the Commission clarify that the amount of in-out revenues that should be removed from the average rates for AEP, ComEd, and Dayton should be based on the amounts calculated by Dr. Henderson in his rebuttal testimony and exhibits.[95] They contend that Dr. Henderson's analysis is the only direct calculation of in-out revenues, and the record does not support any corrections to his analysis. They state that, according to Dr. Henderson, Mr. Heintz vastly over-estimated the amount of in-out revenues and included several numerical and data errors.

69. AEP, Dayton, and Exelon maintain that the Commission erred by failing to clarify that the various corrections to data identified by Dr. Henderson and Mr. Heintz should be adopted.[96] They request that the Commission clarify that the PJM and Midwest ISO transmission owners should reflect the corrections in their compliance filings.

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[94] *Id.* at 8 (citing Tr. 786-788 (Dessender)).

[95] *Id.* at 11 (citing Henderson Rebuttal Test., Ex. No. PTO-81 at 3-33; Ex. Nos. 82-104). Conversely, if the Commission instead grants rehearing, they ask the Commission to use Dr. Henderson's rebuttal testimony and exhibits to calculate the in-out revenues to be included in their average rate determinations.

[96] *Id.* at 17-18 (*citing* Henderson Supplemental Test., Ex. No. PTO-105 at 2-3; Heintz Rebuttal Test., Ex. No. MTO-103 at 2-3).

70. Dominion contends that the Commission erred by failing to require AEP to update its lost revenue calculations to reflect the transmission rates that were changed by a Stipulation and Agreement that was accepted by the Commission in Docket No. ER05-751-000.[97] Dominion argues that rate changes implemented pursuant to that agreement resulted in an unjustifiable disparity between AEP's SECA charges and its other transmission service charges.[98] Dominion maintains that the Commission rejected Dominion's arguments with very limited explanation. Dominion contends that the revenues collected via the SECA charge would not be "in proportion to the benefits that the load within the zone, or [subzone], will realize when it no longer has to pay pancaked rates for transmission," as required by the Commission,[99] because, absent the elimination of through-and-out rates, Dominion would have paid the lower rate under the settlement rather than the higher rate used to calculate AEP's lost revenues.[100] Dominion adds that there is nothing in the record to justify subjecting customers with loads external to the AEP-East zone to higher point-to-point rates for the SECA charges applicable to their loads, while customers with loads internal to the AEP-East zone enjoy the benefit of the much lower rates for transmission service during the same period under the settlement.

71. Dominion requests that AEP's point-to-point transmission rate reduction be applied on a non-discriminatory basis to all customers, including those paying AEP's SECA charges. Dominion states that, by implementing a rate reduction, AEP made it unnecessary for Dominion to seek a rate reduction through a proceeding under section 206 of the FPA. Dominion notes that, in its order accepting and suspending AEP's proposed transmission rate changes, the Commission found that the rates had "not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful."[101] Dominion contends that its only burden of proof has been to show that the lower rate under the settlement is the just and reasonable

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[97] Dominion Request for Rehearing at 4 (citing, *e.g.*, *Keyspan-Ravenswood, LLC v. FERC*, 474 F.3d 804, 812 (D.C. Cir. 2007)).

[98] In particular, Dominion contends that AEP's point-to-point transmission service rate dropped from $1.42 to $1.08106 per kilowatt-month effective November 1, 2005, but AEP used the older $1.42 per kilowatt-month rate to determine its lost revenues. *Id.* at 6-10.

[99] *Id.* at 10-11 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 320 (*quoting* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 85)).

[100] *Id.* at 11-12.

[101] *Id.* at 13, n.19.

rate in effect from November 1, 2005 to March 31, 2006, and it states that it has met that burden. Dominion concludes that there is no reason to distinguish between a just-and-reasonable rate determined under section 205 versus section 206 of the FPA.

3. Commission Determination

72. We affirm that the use of average rates is consistent with the Commission's previous directives and results in just and reasonable rates. We thus will deny the rehearing requests of Constellation and Green Mountain. As the Commission previously explained, the use of average rates avoids the possible under recovery of lost revenues and unfair results due to the alternative use of actual invoices.[102] The use of average rates also ensures that the SECA does not recreate the rate impacts of rate pancaking by converting the SECA back into a transactional charge.[103] We will not reject the use of average rates because they could shift costs from parties with low load factors to parties with high ones. Remedying any such cost shifts would entail the use of actual invoices, which the Commission previously rejected, or tracing how particular reservations were used to deliver energy, which is impractical due to power marketing arrangements and the redirection of reservations to alternate sinks.[104] As the Commission previously explained, delivered energy may be better than reserved transmission capacity at indicating the relative benefits of the elimination of regional through-and-out rates, justifying allocating lost revenues to parties with relatively high load factors.[105]

73. We affirm that in-out revenues should be removed from the numerators of the average rate calculation for the PJM transmission owners, and we will deny rehearing. PJM voluntarily eliminated regional through-and-out rates for in-out transactions, and the Commission did not require it to do so.[106] Contrary to AEP, Dayton, and Exelon's argument that the Commission has failed to hold the PJM transmission owners revenue neutral, the Commission has no obligation to establish a lost revenue recovery

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[102] Order on Initial Decision, 131 FERC ¶ 61,173 at P 150.

[103] *Id*.

[104] *Id*. P 151 (citing Henderson Test., Ex. No. PTO-1 at 14:14-18; *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945) ("allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.")).

[105] *Id*.

[106] *Id*. P 152 (citing Initial Decision, 116 FERC ¶ 63,030 at P 126)

mechanism where transmission owners voluntarily agreed to eliminate rate pancaking without a lost revenue recovery mechanism.[107] While we understand that modifications to the PJM system and operating procedures may have been necessary to retain through-and-out rates for in-out transactions, we reiterate that assigning the costs associated with PJM's voluntary elimination of regional through-and-out rates to load within the combined region would be inconsistent with cost-causation principles. While we agree that load within the combined region benefits from the elimination of through-and-out rates generally, the primary benefit of eliminating regional through-and-out rates for *in-out transactions* is expected to accrue to load zones outside of the combined region where the energy ultimately is consumed.[108]

74. As to the amount of in-out revenues that should be removed from the average rates of PJM transmission owners, we will address whether the PJM transmission owners have complied with the Commission's requirement to remove revenues associated with in-out transactions from the numerator of the average rate in a further order addressing their August 19, 2010 filing to comply with the Order on Initial Decision.

75. Similarly, in regard to AEP, Dayton, and Exelon's request that the Commission clarify that the various corrections to the lost revenue data identified by Dr. Henderson and Mr. Heintz should be adopted, the filings made on August, 19, 2010 to comply with the Order on Initial Decision incorporate these corrections, and we will address them there.

76. We will deny Dominion's request for rehearing and will not require AEP to revise its lost revenue determination to reflect the Stipulation and Agreement that was previously accepted by the Commission in Docket No. ER05-751-000. As the Commission previously noted, it did not require transmission owners to file updated rates in order to justify their level of SECA charges, stating that such a requirement could create an unnecessary impediment to RTO formation.[109] While AEP may have updated its point-to-point transmission rate in the Stipulation and Agreement, it applied a Commission-accepted rate when determining its lost revenues and is not required to use the more recent rate. The Commission also stated that, if any customer believed that the existing rates and revenues that form the basis of the SECA were no longer just and reasonable, it could file a complaint pursuant to section 206 of the FPA.[110] Dominion

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[107] *Id.* (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 42).

[108] *Id.*

[109] *Id.* P 162 (citing July 2003 Order, 104 FERC ¶ 61,105 at P 51).

[110] *Id.* (citing July 2003 Order, 104 FERC ¶ 61,105 at P 51, n.83).

made no such filing under section 206, conceding that it "is not claiming that the AEP transmission rates in 2002 and 2003 were unjust and unreasonable."[111] Further, Dominion has not demonstrated that any "disparity" between the Commission-accepted rate that AEP used to determine its lost revenues and the more recent rate established under the settlement renders the resultant SECA charges unjust, unreasonable, or unduly discriminatory or preferential.

D. Inclusion of Single Company Tariff Revenues

1. Order on Initial Decision

77. In the Order on Initial Decision, the Commission reversed the Initial Decision's finding limiting the SECA to inter-RTO lost revenues. The Commission reaffirmed that the replacement of rate pancaking with license plate rates in this region of the Midwest, for both intra-RTO service and inter-RTO service, resulted in significant immediate cost shifts to the local customers of certain transmission owners.[112] The Commission reiterated that the replacement of intra-RTO rate pancaking with license plate rates without a transitional lost revenue recovery mechanism upon AEP, ComEd, and Dayton's integration into PJM was unjust and unreasonable, and the Commission remedied that situation in the November 2004 Clarification Order,[113] as it affirmed in the May 2010 Rehearing Order. Because AEP, ComEd, and Dayton integrated into PJM in the midst of the inter-RTO rate proceedings and had not had the opportunity to fully recover their lost revenues associated with the elimination of intra-RTO rate pancaking, they were in a different position than other transmission owners.[114] Therefore, the Commission found that AEP, ComEd, and Dayton could recover lost revenues associated with the elimination of intra-RTO rate pancaking through the SECA transition methodology in Docket No. EL04-135-000.

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[111] Dominion Request for Rehearing at 12.

[112] Order on Initial Decision, 131 FERC ¶ 61,173 at P 176 (citing *Alliance Companies*, 94 FERC ¶ 61,070 (2001); *Alliance Companies*, 99 FERC ¶ 61,105 (2002); November 2003 Rehearing Order, 105 FERC ¶ 61,212; and Ameren 2003 Order, 105 FERC ¶ 61,216. *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,090, at P 15 (2003)).

[113] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,243 (2004) (November 2004 Clarification Order).

[114] Order on Initial Decision, 131 FERC ¶ 61,173 at P 176 (citing November 2004 Clarification Order, 109 FERC ¶ 61,243 at P 9).

2. Requests for Rehearing

78. Constellation and Direct Energy, Integrys, and Quest argue that the Commission erred in allowing AEP, ComEd, and Dayton to recover intra-RTO lost revenues through the SECA.[115] Constellation asserts that the Commission failed to adequately explain how AEP, ComEd and Dayton were in a different position than the other former Alliance RTO members,[116] which were required to join either PJM or Midwest ISO.[117] Constellation maintains that each of the former Alliance RTO members were aware that rate pancaking for intra-RTO transactions would be eliminated when they joined an RTO and that each negotiated accordingly.

79. Furthermore, Constellation asserts that, even though the Commission ordered the former Alliance RTO members to join an RTO in April 2002, AEP, Dayton, and ComEd delayed their integration into PJM until 2004, thereby continuing to receive an additional two years of regional through-and-out revenues for transactions within PJM. By allowing AEP, ComEd, and Dayton to recover intra-RTO revenues through the SECA, Constellation alleges that the Commission has effectively allowed AEP, ComEd, and Dayton to receive regional through-and-out revenues for four years after they were required to join an RTO. Constellation claims that, by granting this preferential treatment to AEP, ComEd, and Dayton, the Commission unduly discriminated against the other former Alliance RTO members.

80. Direct Energy, Integrys, and Quest argue that intra-RTO revenues were not lost due to the elimination of regional through-and-out rates but due to their integration into PJM. They also contend that, in its settlement to join PJM, AEP agreed to $366 million for 2003 and 2004 lost regional through-and-out revenues and, thus, was already paid.[118]

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[115] Constellation Request for Rehearing at 39; Direct Energy, Integrys, and Quest Request for Rehearing at 11.

[116] The former Alliance RTO members include: AEP, ComEd, Dayton, Illinois Power Co., Northern Indiana Public Service Co., and the operating companies of FirstEnergy Corp. and Ameren Services Co.

[117] Constellation Request for Rehearing at 40.

[118] Direct Energy, Integrys, and Quest Request for Rehearing at 11.

3. Commission Determination

81. We deny rehearing on this issue. We continue to find that AEP, ComEd, and Dayton are entitled to recover intra-RTO lost revenues through the SECA mechanism. As the Commission stated in the Order on Initial Decision, these new PJM companies were in a different position due to the timing of their integration into PJM. Because AEP, ComEd, and Dayton joined PJM during these proceedings, we find that allowing these companies to recover their lost intra-RTO revenues through the SECA mechanism is appropriate.

82. Regarding Direct Energy, Integrys, and Quest's contention that AEP already recovered its lost regional through-and-out revenues through a settlement proceeding, the Commission already addressed this same argument in the May 2010 Rehearing Order,[119] and we find the argument unconvincing for the same reason explained there.

E. Inclusion of Through-and-Out Revenues Associated with Affiliate Sales

1. Order on Initial Decision

83. In the Order on Initial Decision, the Commission disagreed with the Initial Decision's conclusion that affiliate transactions should be excluded from the SECA. The revenue that a transmission owner receives from an affiliate for through-and-out transmission service should be recorded as revenue for the transmission owner, just as if that revenue came from an unaffiliated entity. That the method by which a transmission provider receives revenue from its affiliate was through intra-corporate accounting does not alter the fact that the transmission provider records less revenue if an affiliate does not pay its affiliated transmission owner the regional through-and-out rate. In addition, the Order on Initial Decision found that the Initial Decision's finding that affiliate revenues should be excluded from the SECA was flawed, as a general matter, because it would require the Commission to consider the revenue that a utility receives from *power* sales to determine whether the rate that the transmission owner charges for *transmission* service is just and reasonable. Therefore, the Order on Initial Decision found that the revenue that a transmission provider previously received from an affiliate should be included in the lost revenue calculation for the SECA.

84. By excluding affiliate transaction revenues from the SECA, the Initial Decision tried to address the possibility that generators may not pass on the savings due to the elimination of regional through-and-out rates to load-serving entities. However, the Commission already recognized that generators may benefit to some extent due to the

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[119] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 160.

elimination of regional through-and-out rates and that those savings may not all be passed on to load-serving entities. The Commission found that this concern (which it noted was the same whether a generator is affiliated with the transmission owner or not) is mitigated for several reasons. Among other things, the Commission found that customers serving load in the combined region would be able to reserve service from the point where power is injected into the combined region to the ultimate delivery point from which load is served for a single, non-pancaked charge, thus enabling load-serving entities to negotiate power supply contracts based on the market price where the resource is located (rather than where the load is located) without incurring additional access charges. In addition, the elimination of regional through-and-out rates will result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation, as well as imports.[120]

85. In the Order on Initial Decision, the Commission stated that there may not be a perfect one-for-one correlation during the transition period between the reduction in prices load-serving entities pay for energy and the savings that a generator realizes by not having to pay regional through-and-out rates. However, the Commission agreed with Commission Trial Staff (Trial Staff) that data showing that the elimination of regional through-and-out rates did not result in any lower prices was too limited to be meaningful given the potential effects of weather, possible generation outages, and fuel cost variation during the short sample period.[121] The Initial Decision did not dispute that this study's sample size was small, but it found that, since Mr. Zakem's testimony was the only testimony that attempted to quantify any price changes, it should be given substantial weight. However, the Commission had already found that the elimination of regional through-and-out rates will put downward pressure on market prices. And the Commission did not impose as a condition to the recovery of lost revenues through the SECA a requirement that transmission owners prove that prices, in fact, went down as a result of the elimination of regional through-and-out rates. In sum, the Commission found that Mr. Zakem's testimony was not a sufficient basis to conclude that, notwithstanding the downward pressure on prices caused by the elimination of regional through-and-out rates, the power rates that generators charged during the entire transition period did not go down.

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[120] Order on Initial Decision, 131 FERC ¶ 61,173 at P 229 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

[121] *Id*. P 230 (citing Initial Decision, 116 FERC ¶ 63,030 at P 156 n.55 (citing Zakem Test., Ex. No. QST-15 at 8:4-11:14).

86. In the Order on Initial Decision, the Commission also found that the Initial Decision erred by concluding that a transmission owner's revenues were not affected by the loss of revenue from regional through-and-out rates paid by an affiliate.[122] The Initial Decision made this error by treating the revenue that a transmission owner receives for transmission service as equivalent to the revenue that the transmission owner's affiliated generators receive for power sales. As the Commission had previously explained, however, the revenues that a transmission owner receives from regional through-and-out rates were credited against the transmission owner's revenue requirement and relieve native load customers of their responsibility for a portion of the transmission owner's cost-of-service in the transmission rates charged them by the transmission owner.[123] In contrast, revenue that the transmission owner's affiliated generator receives for power sales was not considered in the calculation of the transmission rate. The Initial Decision acknowledged this difference but then found, incorrectly, that the record showed that the Commission's statement about credits for through-and-out revenues did not refer to affiliate transactions.[124] The Initial Decision did not cite to any evidence in the record that demonstrated that the credit for through-and-out revenues did not include affiliate transactions. In fact, the Initial Decision noted that AEP testified that the through-and-out revenues from affiliate transactions traditionally had been a significant factor in lowering transmission rates because approximately one half of the point-to-point revenue credits against the cost of service in AEP's last rate case were affiliate transactions.[125]

87. In the Order on Initial Decision, the Commission recognized that the Initial Decision did not give significant weight to AEP's evidence showing that the credit for through-and-out revenues included affiliate transactions because, according to the Initial Decision, the Commission found in a prior order that this case did not involve AEP's revenue requirement or transmission rate.[126] In the Order on Initial Decision, the Commission disagreed with that assessment. What the Commission stated, in the language cited by the Initial Decision, was that it had previously accepted the transmission owners' existing cost-of-service and revenue levels as just and reasonable and that the Commission's actions in this proceeding would maintain, not change, the

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[122] *Id.* P 231 (citing Initial Decision, 116 FERC ¶ 63,030 at P 183).

[123] *Id.* (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 19 n.36).

[124] *Id.* (citing Initial Decision, 116 FERC ¶ 63,030 at P 173 n.63).

[125] *Id.* (citing Initial Decision, 116 FERC ¶ 63,030 at P 176).

[126] *Id.* P 232 (citing Initial Decision, 116 FERC ¶ 63,030 at P 176, 172 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 47, 49)).

level of these revenues.[127] The Commission also found that, based on the record in the proceeding, it had no reason to believe that the transmission owners' existing rates or revenues are unjust and unreasonable and, therefore, did not require Midwest ISO and PJM to submit updated cost-of-service studies in their compliance filings.[128] It was not inconsistent with those findings to recognize that the revenue that a transmission owner receives from its affiliated generators through regional through-and-out rates was considered as a credit that reduced the existing transmission rates. In fact, by prohibiting affiliate revenues from being included in the SECA calculations, it was the Initial Decision that effectively would require an adjustment to be made to the transmission owners' existing rates and revenues, which was inconsistent with the Commission's previous findings.

88. Since the parties that support the exclusion of affiliate revenues from the SECA were advocating an adjustment to the existing cost-of-service and revenue levels of the transmission owners, the burden was on those parties to demonstrate that the adjustment was just and reasonable. Even if it were appropriate under these unusual circumstances to consider the impact of generator revenues on transmission revenues, the basis for excluding affiliate transactions from the SECA would be a finding that affiliated generators received the same amount of revenue during the transition period as they did during the test period. The only support for this finding, however, was the testimony of Mr. Zakem, which was based on a very small sample of prices during the transition period. In the Order on Initial Decision, the Commission also noted that the Initial Decision relied on Mr. Zakem's conclusions, not because his conclusions were well supported, but simply because his was the only quantified testimony on the record about prices during the transition period.[129] However, transmission owners did not necessarily have to submit studies to show that the prices that their affiliated generators charged during the transition period went down because transmission owners were not advocating adjustments to their existing revenue levels. Accordingly, in the Order on Initial Decision, the Commission found that the record did not support a finding that affiliate transactions should be excluded from the SECA calculations.

89. Furthermore, the Order on Initial Decision found that the Initial Decision did not support imposing a requirement for affiliated generators to show that prices went down but not imposing the same requirement for unaffiliated generators. It was possible that an affiliated generator (and its corporate parent) had an increase in profits during the

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[127] *Id.* (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 47).

[128] *Id.* (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 49).

[129] *Id.* P 233 (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 156 n.55).

transition period that may be attributable in part to the elimination of regional through-and-out rates, but that was also possible for an unaffiliated generator (and its corporate parent). There was no evidence in the record that affiliated generators were in a better position during the transition period to resist downward price pressure caused by the elimination of regional through-and-out rates than were unaffiliated generators. Thus, it was the Initial Decision that arguably unduly discriminated – against affiliated generators, by imposing on only them a requirement to show that they passed the savings associated with the elimination of regional through-and-out rates to the affiliated transmission providers.

2. Requests for Rehearing

90. AMP, BG&E, BP Energy, Green Mountain, and Direct Energy, Integrys, and Quest filed requests for rehearing of the Commission's finding in the Order on Initial Decision that the regional through-and-out revenue that a transmission owner previously received from an affiliate should be included in the lost revenue calculation for the SECA.[130]

91. All parties that requested rehearing on this issue claim that the Commission's decision to allow affiliate transactions to be included in the SECA calculations should be reversed because revenues received by one corporate affiliate from another corporate affiliate do not have an impact on the revenue for the corporation as a whole. They argue that including affiliate transactions in the SECA calculations results in an unjust and unreasonable increase in revenue for the entity receiving affiliate-related SECA payments.

92. BG&E and Direct Energy, Integrys, and Quest cite AEP as an example to show that the elimination of the regional through-and-out rate paid by affiliates does not have an impact on a corporation's overall revenue. They assert that, because the transmission side of AEP no longer collects regional through-and-out revenue from its generation affiliate, and the generation affiliate no longer incurs a transmission expense, the result is a net wash to AEP. Direct Energy, Integrys, and Quest state that it is a fact – not an opinion or an argument – that AEP has collected SECA revenue based on internal accounting cross-charges that did not represent revenues that were lost to AEP when the regional through-and-out rate was eliminated. BG&E states that the AEP-affiliated regional through-and-out rate payments amount to approximately $88 million, and AEP will be picking up that amount of new net earnings never before realized at the expense of non-native load customer rate zones, in part from the stockholders of competitor transmission-owning companies. According to BG&E and Direct Energy, Integrys, and

[130] Order on Initial Decision, 131 FERC ¶ 61,173 at P 228, 234.

Quest, allowing affiliate transactions to be included in the SECA provides unjust enrichment to AEP and, therefore, makes the SECA unjust and unreasonable, under any standard of review.[131]

93. Green Mountain disputes the statement in the Order on Initial Decision that revenue received by a transmission owner from an affiliate is recorded as revenue to the transmission owner in the same manner as revenue from an unaffiliated transmission customer.[132] Green Mountain argues that this ignores the fact that the same revenue received from an affiliate is recorded as an expense by that affiliate, producing a wash for the corporation as a whole, and its shareholders.[133] Similarly, AMP argues that it presented evidence showing that, if a utility is allowed to recover regional through-and-out revenue from outside sources (e.g., load-serving entities like AMP that were assessed SECA charges) that the utility previously recovered from an affiliate, then the combined utility will not be revenue neutral but will be ahead.[134] Thus, AMP argues that it is necessary to reduce the claimed lost revenues by eliminating any and all regional through-and-out charges paid to an affiliate.

94. AMP, Green Mountain, and Direct Energy, Integrys, and Quest also argue that the inclusion of affiliate transactions in the SECA calculations is inconsistent with the purpose of the SECA as expressed in the Commission's prior orders. AMP argues that allowing affiliate transactions to be included in the SECA calculations means that load-serving entities will provide transmission owners with additional profits (rather than replacing revenues that were lost), which goes beyond the original purpose of the SECA.[135] Green Mountain claims that the SECA calculations were swollen by the inclusion of amounts that were not in any real sense lost to the transmission owner, which goes beyond the stated purpose of the SECA to replace "revenues lost due to the

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[131] BG&E Request for Rehearing at 47-49; Direct Energy, Integrys, and Quest Request for Rehearing at 13-16.

[132] Green Mountain Request for Rehearing at 7 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 228).

[133] *Id*.

[134] AMP Request for Rehearing at 34 (citing Norton Answering Test., Ex. No. AMP-1 at 29-30).

[135] *Id*.

elimination of through and out rates."[136] In addition, Green Mountain claims that, by allowing a transmission owner that is not losing regional though-and-out revenues to collect a SECA from its customers, the Commission required the shifting of revenues from customers to transmission owners, in violation of the Commission's desire to "prevent undue cost shifting among various transmission owners and customers."[137] Similarly, Direct Energy, Integrys, and Quest argue that the inclusion of revenues from affiliate transactions in the SECA calculation creates a financial windfall for the utility, violating the Commission's order that the SECA is not intended to provide greater revenues for the utility.[138] Even assuming that Direct Energy, Integrys, and Quest had the burden to show that the affiliate revenues are not lost (a contention with which they disagree), they state that they have more than met that burden.[139]

95. According to BP Energy, fatal to the Order on Initial Decision's finding on the affiliate transaction issue is the assumption that, for ratemaking purposes, the elimination the regional through-and-out rate should be treated the same regardless of whether the rate represents a true variable cost or not. BP Energy argues that the regional through-and-out rate represents a true variable cost when a non-affiliate is the seller, but, when a merchant affiliate is the seller, the regional through-and-out rate is booked as an expense that is offset by revenue booked by the parent. BP Energy argues that the Order on Initial Decision did not adequately explain why this critically important economic distinction is not relevant in terms of justifying actual benefits to customers.[140]

96. Further, BP Energy argues that there is no substantial evidence that eliminating internal payments between and offsetting revenues among affiliates benefits customers in the ways that the Commission has identified or would result in non-affiliate generation becoming more competitive with affiliate generation. Because the elimination of the regional through-and-out rate does not impact, for example, AEP's marginal costs, AEP's marketing affiliate remains motivated to make sales at prices that at least clear the unchanged marginal cost (i.e., to sell at a price just below that of a competitor).

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[136] Green Mountain Request for Rehearing at 10 (citing November 2004 Order, 109 FERC ¶ 61,168 at P 61).

[137] *Id.* (November 2004 Order, 109 FERC ¶ 61,168 at P 56).

[138] Direct Energy, Integrys, and Quest Request for Rehearing at 13, 18 (citing Going Forward Principles Order, 106 FERC ¶ 61,262 at P 20).

[139] *Id.* at 18-19.

[140] BP Energy Request for Rehearing at 50.

Therefore, according to BP Energy, the decision to include affiliate transactions in the SECA calculations was not supported by substantial evidence and was arbitrary and capricious.[141]

97. BG&E argues that the Commission relied on accounting treatment to decide a rate issue but did not cite any authority to do so. BG&E contends that the case law is quite the opposite and that the Commission has previously found ratemaking is not governed by accounting.[142] BG&E states that it has always been the case that, "[t]he facts, not accounting theory, should control."[143] BG&E argues that allowing company bookkeeping to trump the fact that the regional through-and-out revenues stay within the corporate family of which there is only one group of shareholders would exalt form over substance. According to BG&E, that is exactly the approach to ratemaking that the Supreme Court condemned when it ruled that "it is the result reached not the method employed which is controlling . . . . It is not theory but the impact of the rate order which counts."[144]

98. Several parties also dispute the Commission's finding that "the revenues that a transmission owner receives from regional through-and-out rates are credited against the transmission owner's revenue requirement and relieve native load customers of their responsibility for a portion of the transmission owner's cost of service in the transmission rates charged them by the transmission owner."[145] Direct Energy, Integrys and Questcall this view unsupported and flawed.[146] Integrys states that evidence shows that the interdepartmental sales adjustments that AEP, for example, utilized to account for affiliate transactions are internal cross-charges that do not affect total corporate costs and

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[141] *Id*. at 51.

[142] BG&E Request for Rehearing at 46 (citing *North Penn Gas Co.*, 13 FERC ¶ 61,084, at 61,174 (1980)).

[143] *Id*. at 46 (citing A. J. Gustin Priest, *Principles of Public Utility Regulation* 592 (1969)).

[144] *Id*. (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944)).

[145] *See, e.g.*, Direct Energy, Integrys, and Quest Request for Rehearing at 16 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 231 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 19 n.36)).

[146] *Id*.

are not part of the revenue requirement.[147] AMP also disputes the Commission's statement about the crediting of through-and-out rates and argues that this statement is not supported by evidence, and notably, none is cited in the Commission's discussion on this issue.[148]

99. Green Mountain argues that the Commission's observation that regional through-and-out revenues are credited against the transmission owner's cost of service fails to justify the inclusion of affiliate transactions in the SECA calculations. Green Mountain states that the Commission cited no record evidence that establishes that the credit to the transmission cost of service from regional through-and-out revenues includes affiliate transactions. Instead, Green Mountain contends, the Commission turned the burden of proof completely on its head by stating that the Initial Decision cites no evidence that the credit does not include such transactions. According to Green Mountain, the transmission owners, as proponents of the rate change that is the SECA, must establish with evidence of record that such a credit does include such revenues. In addition, Green Mountain argues that there is no evidence of record that SECA revenues have been credited against any transmission owner's cost of service. Green Mountain states that, for example, a transmission owner with a stated rate would credit SECA revenues against the transmission cost of service only if the transmission owner happened to have a rate increase filing timed such that the SECA revenue credits would have been captured in the cost of service. Green Mountain contends that there is also no evidence that any transmission owner with a formula rate flowed through any percentage of the SECA revenues to its transmission customers in the form of revenue credits.[149]

100. Green Mountain contends that, even if the logic of the Commission's credit argument is correct, it demonstrates that the inclusion of affiliate transactions unjustly enriches the transmission owner. Green Mountain argues that the transmission owner with a generation affiliate suffers no economic harm from the loss of the regional though-and-out revenue because, if such revenue was in fact lost, the transmission owner would have no revenues to credit against the cost of service. The transmission owner's transmission customers would, therefore, be charged the full cost of service rate without credits for regional thorough-and-out revenues. Green Mountain asserts that under the Commission's interpretation, however, the transmission owner nevertheless would be permitted to include those affiliate-related revenues in the SECA to be recovered from load. Green Mountain concludes, therefore, that the transmission owner is compensated

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[147] *Id*. at 15.

[148] AMP Request for Rehearing at 35.

[149] Green Mountain Request for Rehearing at 7-8.

for a loss that it has not incurred. If anyone has incurred a loss, according to Green Mountain, it is the load that is paying the higher transmission charges plus a SECA charge that includes revenues associated with affiliate transactions.[150]

101. Direct Energy, Integrys, and Quest and AMP argue that the Commission erred when it found that testimony presented by Mr. Zakem was not a sufficient basis to conclude that, notwithstanding the downward pressure on prices caused by the elimination of regional through-and-out rates, the power rates that generators charged during the entire transition period did not go down.[151] Direct Energy, Integrys, and Quest argue that Mr. Zakem's testimony persuasively showed that there was no discernable change in prices after the regional through-and-out rate was eliminated. According to them, the Commission's finding that Mr. Zakem's testimony was "too limited to be meaningful given the potential effects of weather, possible generation outages, and fuel cost variation during the short sample period" was complete conjecture and, in any event, was taken out of context.[152] They state that Mr. Zakem was responding to the unsupported claim by Trial Staff that power prices must have gone down as a result of the elimination of the regional through-and-out rate and that Mr. Zakem conclusively showed Trial Staff to be wrong. Direct Energy, Integrys, and Quest contend that hearing participants had every opportunity to rebut this evidence but did not. They argue that, moreover, the Commission's conclusion that it had "already found that the elimination of regional through-and-out rates will put downward pressure on market prices" is a conclusion with no support that was made prior to the hearing when evidence showed just the opposite.[153]

102. AMP calls nonsensical the Commission's finding that the evidence presented by Mr. Zakem, which AMP claims showed that prices charged by generators stayed essentially the same once regional through-and-out rates were eliminated, was not a sufficient basis to contradict the Commission's theory that the elimination of regional through-and-out rates would put downward pressure on prices that would be passed along to load-serving entities. AMP argues that the Commission's theory is not substantial evidence nor is it logical. AMP avers that, where the seller of power is an affiliate, the

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[150] *Id*. at 8-9.

[151] *See*, *e.g.*, AMP Request for Rehearing at 35 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 230).

[152] Direct Energy, Integrys, and Quest Request for Rehearing at 18 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 230).

[153] *Id*. (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 230).

seller may ignore some or all of the transmission costs that it pays to an affiliate 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. As support for that conclusion, AMP cites the example in its reply brief, which the Initial Decision found supported this claim.[154]

103. Green Mountain disputes the need for any price data because it believes that the Commission created a red herring by stating that, by excluding affiliate transaction revenue from the SECA, the Initial Decision was trying to address the possibility that generators may not pass on to customers savings due to the elimination of regional through-and-out rates. Green Mountain argues that the Initial Decision eliminated affiliate revenues from the SECA calculation because dollars that had been paid by one affiliate to another were not in fact lost by the transmission owner; they simply remained in the left pocket instead of being transferred to the right pocket.[155]

104. Green Mountain also disputes the Commission's finding that parties opposing the inclusion of affiliate transactions in the SECA calculations are advocating a change in existing cost of-service and revenue levels. Green Mountain argues that what is at stake is not each transmission owner's revenue requirement but the extent to which its transmission revenues were lost as a result of the elimination of the regional through-and-out rates. Green Mountain avers that, with regard to that question, the FPA unequivocally assigns the burden of proof to the transmission owners themselves, and they failed to carry that burden.[156]

105. BG&E disagrees with the Commission's finding that it is arguably unduly discriminatory to impose on only affiliated generators a requirement to show that they passed the savings associated with the elimination of regional through-and-out rates to the affiliated transmission providers. BG&E states that this is essentially a finding that all free-loaders must be treated equally and calls this a misuse of the safeguard against undue discrimination in the FPA. BG&E states that it is the ratepayer that is to be protected against such discrimination and that this protection was never intended to allow price gouging to be extended to all classes of billing entities in the name of equality. BG&E claims that the Commission knows that affiliate transactions do not produce net

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[154] AMP Request for Rehearing at 36-37 (citing Initial Decision, 116 FERC ¶ 63,030 at P 163 (citing AMP Reply Brief at 22 n.23)).

[155] Green Mountain Request for Rehearing at 7 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 229).

[156] *Id*. at 9-10 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 233).

revenues within the corporate entity, and speculation that other entities may also be over-collecting should not be a factor to determine whether or not to disallow affiliate transactions in the SECA calculations. If the Commission's intent was to prevent inconsistent outcomes, the better remedy, according to BG&E, would be to outlaw the SECA entirely, not to open it up to rampant misuse because not all misuse can be avoided.[157]

106. Direct Energy, Integrys, and Quest note that the Commission considered affiliate costs and revenues in the past and cites a June 18, 2009 rehearing order in the California refund proceedings,[158] where Integrys states that the Commission required those sellers seeking to collect costs associated with affiliate transactions to show their actual costs in order to recover them. They note that the Commission in that order stated:

> The Commission's policy for addressing affiliate transactions and the authority of the Commission to disregard corporate forms when necessary to fulfill its statutory obligations are well documented. In *Town of Highlands v. Nantahala*,[[159]] the Commission reiterated the general rule that an agency may disregard the corporate form in the interest of public convenience, fairness, or equity. The Commission explained that this principle of allowing agencies to disregard corporate form is flexible and practical in nature, and corporations may be regarded as one entity for the purposes with which the agency is immediately concerned, even though they are legitimately distinct entities for other purposes. No misconduct on the part of the corporation is necessary; rather, the inquiry is simply a question of whether the statutory purposes would be frustrated by the corporate form. Accordingly, the Commission may regard two entities as one when necessary to meet a statutory goal. In the case of the cost filings, our statutory goal is the avoidance of a confiscatory outcome. The Commission has determined that the corporate entity as a whole would not

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[157] BG&E Request for Rehearing at 46-47 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 234).

[158] Direct Energy, Integrys, and Quest Request for Rehearing at 16 (citing *San Diego Gas and Elec. Co. v. Sellers of Market Energy and Ancillary Services*, 127 FERC ¶ 61,269 (2009) (California Refund Rehearing Order), *order on reh'g*, 131 FERC ¶ 61,144 (2010)).

[159] *Town of Highlands, N.C. v. Nantahala Power & Light Company*, 37 FERC ¶ 61,149 (1986).

> suffer confiscatory loss if it recovers the actual cost of affiliate generation.[[160]]

107. Direct Energy, Integrys, and Quest note that the Commission also stated that the entities involved "must be treated as a single entity for purposes of assessing whether the company as a whole experienced an overall revenue shortfall attributable to the [mitigated market clearing price] refund methodology"[161] They argue that substituting the words "elimination of regional through-and-out rates" for "mitigated market clearing price refund methodology" results in the exact situation in this case. They argue, therefore, that the Commission in the SECA proceedings should take the same "one company" approach that the Commission took in the California refund proceedings.

108. BP Energy also argues that the decision to include affiliate transactions in the SECA calculation should be reversed because it constitutes an unexplained departure from the Commission's decision in the California refund proceeding. BP Energy states that, in that proceeding, the Commission permitted affiliate generators only to recover actual costs to the corporate entity of transactions with its affiliates and stated that "[t]he Commission's intent is clear to allow for recovery of sellers' actual out-of-pocket costs . . . ."[162] BP Energy argues that, because there are no actual or out-of pocket costs incurred for the corporate entity when a merchant affiliate pays transmission charges to a transmission affiliate, the elimination of regional through-and-out rates causes no loss to the corporation. Thus, according to BP Energy, the finding in the Initial Decision to exclude affiliate transactions from the SECA calculation is consistent with Commission precedent and should have been affirmed.

109. BP Energy states that the record includes discussion of generalized benefits supposedly resulting from the implementation of the SECA (such as more efficient dispatch of generation) but does not include substantial evidence that customers experienced reduced power purchase prices because of the elimination of regional through-and-out rates. BP Energy states that, as a reviewing federal court has explained, "faith" in the generalized benefits associated with the elimination of regional through-and-out rates is insufficient to uphold the Order on Initial Decision, and instead, the order

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[160] Direct Energy, Integrys, and Quest Request for Rehearing at 16-17 (citing California Refund Rehearing Order, 127 FERC ¶ 61,269 at P 221 (citations omitted)).

[161] *Id.* at 17 (citing California Refund Rehearing Order, 127 FERC ¶ 61,269 at P 222).

[162] BP Energy Request for Rehearing at 52 (citing *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 114 FERC ¶ 61,070, at P 93 (2006)).

can only be upheld if it is supported by "substantial evidence on the record as a whole . . . ."[163] BP Energy states that no party provided a study or any meaningful analysis that supported the conclusion that the costs of merchant affiliate transmission are included in the power sale prices paid by ultimate (primarily third-party) customers of merchant affiliates.[164]

110. Green Mountain argues that the record here does not indicate whether electric energy costs declined following the elimination of regional through-and-out rates, the extent of any such decline, or the extent to which the benefits that might have resulted from such a decline accrued to the Green Mountain subzone. Green Mountain argues that the Commission has held that generalized claims that all customers, or particular classes of customers, will derive some benefit from transmission investments is insufficient to justify allocating costs to those customers in the absence of a quantification of the benefit that particular customers will receive or a comparison of the value of the benefits to the costs proposed to be assigned.[165] In addition, Green Mountain argues that the courts have made clear that compliance with the general principle that rates must reflect to some degree the costs caused by the customer who must pay the rates is evaluated "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by the party."[166] Green Mountain also argues that, even if it did receive some benefits, the existence of some, unquantifiable level of benefits does not justify the assignment of $32 million in SECA costs to Green Mountain.

3. Commission Determination

111. We continue to find that the revenue that a transmission provider previously received from an affiliate should be included in the lost revenue calculation for the SECA. No party has raised an argument on rehearing that we have not already addressed or that causes us to revisit our determination. Therefore, we will deny rehearing on this issue.

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[163] *Id.* at 49-50 (*citing Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (*ICC*)).

[164] *Id.* at 50.

[165] *Id.* at 12-13 (citing *Transcontinental Gas Pipe Line Corp.*, 112 FERC ¶ 61,170, at P 106 (2005)).

[166] *Id.* at 13 (citing *ICC*, 576 F.3d at 476 (*quoting Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004))).

112. As we explain below, we find unconvincing the argument that, because affiliate transactions are recorded as intra-corporate transfers, the elimination of regional through-and-out rates has no impact on the revenue of the overall corporation. In addition, the argument that regional through-and-out payments made by a generator to an affiliated transmission owner have no impact on the rates paid by native load and non-affiliated customers is in error. Parties on rehearing argue at length that there is no revenue impact on a corporation as a whole when one affiliate transfers money to another affiliate. As a general matter, it is correct that, when a generation affiliate makes a payment to its transmission affiliate for regional through-and-out service, the generation affiliate books the payment as an expense and the transmission affiliate books the same payment as revenue. However, as the Commission reiterated in the Order on Initial Decision, the revenue that the transmission affiliate receives from its generation affiliate then acts to offset or reduce a portion of the cost of service that the transmission affiliate would otherwise recover from other tariff customers.[167] In addition, SECA payments that a transmission affiliate collects to replace revenue that it previously received from a generation affiliate provides a similar benefit to tariff customers because the SECA payments also reduce or offset (or replace the lost revenues that reduce or offset) a portion of the transmission revenue requirement under the transmission owner's tariff. Therefore, including affiliate transactions in the SECA calculations is consistent with the purpose of the SECA because it maintains the transmission owner's existing cost of service and revenue levels.[168]

113. Although Direct Energy, Integrys, Quest, AMP, and Green Mountain dispute that transmission affiliates provide a credit based on revenue received from generation affiliates, we note that the Commission stated in Order No. 888-A that transmission affiliates must have a rate mechanism in place to credit revenues from off-system sales for the benefit of tariff customers. [169] In addition, the Commission explicitly required

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[167] Order on Initial Decision, 131 FERC ¶ 61,173 at P 231 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 19 n.36).

[168] Because affiliate transactions do have a revenue impact on the parent corporation, BG&E's claim that the Commission relied on accounting treatment to decide a rate issue is incorrect. Accordingly, the court cases that BG&E cites regarding accounting treatment are inapplicable to this proceeding.

[169] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC

(continued…)

that revenue from the transmission component of all off-system uses of the transmission system (whether by the transmission owner or transmission customer) must be treated on a comparable basis, whether through rate design or through revenue credits.[170] If it were correct that a transmission owner did not include a crediting mechanism (through rate design or through revenue credits) in its transmission rate to account for through-and-out revenue that it receives from affiliates and non-affiliates alike, then that transmission owner's rates would be in violation of Order No. 888. However, as the Commission previously stated, and as we continue to find based on the record in this proceeding, there is no reason to believe that the transmission owners' existing rates or revenues are unjust and unreasonable.[171] Similarly, no party on rehearing cites record evidence that would provide us with a convincing basis to conclude that the transmission owners' existing rates violate Order No. 888. If Direct Energy, Integrys, Quest, AMP, and/or Green Mountain believe that a transmission owner's existing rates violate the Order No. 888 requirement to provide a crediting mechanism for regional through-and-out revenue that the transmission owner receives from both affiliates and non-affiliates, then they have the burden to demonstrate that the transmission owner's existing rates are unjust and unreasonable. In this case, they have not met that burden.

114. In any event, there is evidence in the record to demonstrate that transmission owners provide a credit for regional through-and-out rate revenue that they receive from affiliates. For example, the Initial Decision specifically noted that AEP presented testimony showing that the regional through-and-out revenues that AEP receives 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 AEP's cost of service in the last rate case were affiliate transactions.[172] AEP witness, Mr. Bethel, also testified that the regional through-and-out revenue that AEP receives

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¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[170] *See* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, at 30,310..

[171] Order on Initial Decision, 131 FERC ¶ 61,173 at P 232 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 49).

[172] Initial Decision, 116 FERC ¶ 63,030 at P 173 n.63 and P 176. The Initial Decision did not give significant weight to AEP's evidence, s*ee* Order on Initial Decision, 131 FERC ¶ 61,173 at P 232, but the Commission disagreed with that finding.
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(affiliate and non-affiliate) is credited back to customers.[173] Notably, the Initial Decision relied on Mr. Bethel's statement that nearly fifty percent of AEP's point-to-point revenues were associated with affiliate sales,[174] but it did not give significant weight to Mr. Bethel's next statement that all such revenues were credited back to customers.[175] Similarly, contrary to Green Mountain's assertion that there is no evidence in the record that SECA revenues were credited against any transmission cost of service, Mr. Bethel also testified that the SECA payments that AEP received were applied to its cost of service to lower its transmission rates.[176]

115. We also continue to find that the testimony presented by Mr. Zakem is not a sufficient basis to conclude that, notwithstanding the downward impact on prices that is reasonably expected due to the elimination of regional through-and-out rates, the power rates that generators charged during the entire transition period did not go down.[177] Mr. Zakem described his review of market prices as cursory, and he compared prices on the Cinergy daily index and the North ECAR[178] daily index only from mid-November 2004 through mid-December 2004, excluding the week of the Thanksgiving holiday.[179] In other words, the only evidence to support a conclusion that the elimination of regional through-and-out rates did not cause prices to decline during the entire 16-month transition period is Mr. Zakem's analysis of two daily indexes during one week before the

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[173] *See*, *e.g.*, Tr. 1310:3-12, 1311:2-3, 1315:18-23, 1316:2-10, 1363:16-1364:4 (Bethel); *see also* AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 36 (citing crediting provisions in the PJM tariff).

[174] Initial Decision, 116 FERC ¶ 63,030 at P 182 (citing Tr. at 1315:22 (Bethel)).

[175] Tr. at 1315:23 (Bethel).

[176] *See*, *e.g.*, Tr. 1302:15-20, 1316:10-14, 1317:4-5, 1364:17-22, 1366:5-1367:14 (Bethel); *see also* AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 37 (stating that AEP's zonal rates in effect under the PJM tariff from November 1, 2005 through March 31, 2006 incorporated reductions to AEP's transmission revenue requirement and zonal rates for the SECA revenues that AEP expected to receive) (citing AEP Offer of Settlement, Ex. No. DVP-4).

[177] Order on Initial Decision, 131 FERC ¶ 61,173 at P 230.

[178] East Central Area Reliability Coordination Agreement.

[179] Initial Decision, 116 FERC ¶ 63,030 at P 156 (citing On-Peak Daily Indexes Graph, Ex. No. QST-16); *see also* Zakem Cross-Answering Test., Ex. No. QST-15 at 10.

December 1, 2004 elimination of regional through-and-out rates and two weeks immediately after. In addition, as the Commission explained in the Order on Initial Decision, Mr. Zakem did not assess the potential effects of weather, possible generation outages, and fuel cost variation during the short sample period.[180] The Commission has previously explained why the elimination of the regional through-and-out rates puts downward pressure on prices.[181] In the absence of any other evidence to corroborate Mr. Zakem's claims, and given the weaknesses of Mr. Zakem's testimony, it is appropriate for the Commission to find that evidence insufficient to conclude that the prices generators charged during the entire transition period did not go down. As important, the Commission's support for elimination of RTOR – that it puts downward pressure on prices – was not an issue set for hearing in these proceedings. Parties disputing such support should have sought rehearing of the Commission's earlier orders.[182]

116. Furthermore, contrary to Green Mountain's claim, it was not a red herring for the Commission to observe that, by excluding affiliate transaction revenue from the SECA, the Initial Decision tried to address the possibility that generators may not pass on savings to customers due to the elimination of regional through-and-out rates.[183] The Initial Decision expressly relied on Mr. Zakem's (flawed, we find) conclusion that prices did not go down after the elimination of regional through-and-out rates as support for the finding that affiliate transactions should not be included in the SECA calculations.[184] In any event, as we explain above, Green Mountain's claim that affiliate revenues are not properly considered lost revenues is also incorrect.

117. We also disagree with Green Mountain's argument that the Commission was incorrect to place the burden on parties advocating for the exclusion of affiliate

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[180] Order on Initial Decision, 131 FERC ¶ 61,173 at P 230.

[181] *See, e.g.*, *id.* P 229 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45); *see also* May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85.

[182] July 2003 Order, 104 FERC ¶ 61,105; *Alliance Co.*, 100 FERC ¶ 61,137, *order on reh'g*, 103 FERC ¶ 61,274; a*ccord* Order No. 2000, FERC Stats. & Regs. ¶ 31,089, *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092, *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[183] Order on Initial Decision, 131 FERC ¶ 61,173 at P 229.

[184] *See, e.g.*, Initial Decision, 116 FERC ¶ 63,030 at P 156, 165-166.

transactions from the SECA calculations.[185] As the Commission explained, prohibiting affiliate revenues from being included in the SECA calculations effectively would require that an adjustment be made to the transmission owners' existing rates and revenues, which is inconsistent with the Commission's previous findings.[186] Green Mountain implicitly acknowledges as much by stating that, if it is correct that affiliate transactions provide a credit against a transmission owner's cost of service, then a transmission owner that does not receive SECA payments to replace affiliate revenue could still be made whole by charging a higher transmission rate (i.e., a rate not reduced by the credit for affiliate transactions).[187] As we explain above, affiliate transactions do provide a credit. Therefore, consistent with Green Mountain's own argument, excluding affiliate transactions from the SECA calculation would necessitate that a transmission affiliate change its existing rates so that it can collect regional-through-and-out revenue that it previously received from its generation affiliate, not through the SECA, but instead by increasing the rates for transmission service for delivery to load in its pricing zone, in order to remain revenue neutral. Parties that want to exclude affiliate transactions from the SECA calculation effectively seek a decrease to transmission owners' existing rates and revenues for through and out service and correctly bear the burden to show that the existing rates are unjust and unreasonable and that the change that they seek is just and reasonable. Where transmission owners have met the burden to show lost revenues, as they have here, they do not bear the additional burden of proving their pre-existing, Commission-accepted revenue requirement is just and reasonable.

118. BG&E claims that, by noting that it was arguably unduly discriminatory to treat affiliates differently than non-affiliates,[188] the Commission allowed affiliate transactions to be included in the SECA calculations because "all free-loaders must be treated equally" and because "price gouging" is acceptable so long as all entities can do so on an equal basis.[189] We reject this claim as a gross mischaracterization. As we explain above, amounts that an affiliate generator pays to its affiliated transmission owner, and SECA revenues that a transmission owner receives based on affiliate generator transactions, have an impact on the revenues of a corporation as a whole. Revenues from an affiliate generator, and related SECA payments to replace those revenues, act to reduce the

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[185] Order on Initial Decision, 131 FERC ¶ 61,173 at P 233.

[186] *Id.* P 232.

[187] Green Mountain Request for Rehearing at 8-9.

[188] Order on Initial Decision, 131 FERC ¶ 61,173 at P 234.

[189] BG&E Request for Rehearing at 46-47.

revenues that the transmission affiliate would otherwise receive under its transmission tariff from other customers. Therefore, as the Commission explained, an affiliated generator is in no better position than an unaffiliated generator to resist the downward pressure on prices that results from the elimination of regional through-and-out rates.[190] Given this, the Commission was correct to note that the directive in the Initial Decision to treat affiliates and non-affiliates differently would arguably result in undue discrimination.[191] FPA section 205's rate protections are afforded to both affiliates and non-affiliates, in any event, contrary to BG&E's claim.

119. We find that reliance by Direct Energy, Integrys, Quest, and BP Energy on the California refund proceeding is misplaced. Other than the fact that affiliate transactions were involved in both proceedings, they do not explain how the facts in the California refund proceeding are in any way similar to, or why the Commission's findings based on the facts of that case should have any bearing on, the Commission's findings in the SECA proceeding. It does not follow that, if the Commission in the California refund proceeding, under very specific circumstances and by looking at case-specific facts, addressed affiliate transactions one way, the Commission necessarily must make the same finding in the SECA proceeding, which has its own specific circumstances and very different, case-specific facts; the former involved, broadly speaking, issues of conduct in power sales markets in California, while the SECA proceeding flows from the elimination of regional through-and-out transmission rates in the Midwest ISO and PJM and involves the development of a transition mechanism to address the elimination of such transmission rates. Indeed, it appears that the principal similarity between these two cases is how *dis*similar they are to any other Commission proceeding, let alone to each other.[192]

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[190] Order on Initial Decision, 131 FERC ¶ 61,173 at P 234.

[191] We note that the Commission did not base its decision to allow affiliate transactions to be included in the SECA calculations on a finding of undue discrimination. We merely noted that the Initial Decision would impose a disparate requirement on affiliated versus unaffiliated generators, and that disparate treatment might rise to the level of unduly discriminatory treatment. *Id.*

[192] As just one example, Direct Energy, Integrys, and Quest quote paragraph 221 in the California Refund Rehearing Order to support their claim that the Commission should exclude affiliate transaction from the SECA. However, they do not quote the second part of the same paragraph, which we believe makes clear the differences in these two cases and demonstrates the inapplicability of the case-specific findings from that order to the SECA proceeding:

(continued…)

120. We disagree with Direct Energy, Integrys, and Quest's argument that, if you take a sentence from the California Refund Rehearing Order and replace the words "mitigated market clearing price methodology" with the words "elimination of regional through-and-out rates," it results in the exact situation that is occurring in the SECA proceeding.[193] Direct Energy, Integrys, and Quest do not explain why they believe the mitigated market clearing price methodology is equivalent to the elimination of regional through-and-out rates. Simply replacing in a Commission order the words that describe the subject of one proceeding with the words that describe the subject of a very different proceeding provides no rational basis to conclude that the Commission's finding in the first order should apply equally to the second.

121. Finally, we are not persuaded by BP Energy's argument regarding generalized benefits. As we have explained, the record, as a whole, supports our finding; we are not relying on "faith." BP Energy's arguments are, additionally, a collateral attack on the Commission's earlier SECA orders and the findings in those orders. BP Energy had the opportunity to timely request rehearing of the Alliance 2002 Order, July 2003 Order, November 2004 Order, February 2004 Order, and February 2005 Order, and failed to do so.

> Therefore, in the case of sellers claiming cost offsets for affiliate purchases, it becomes necessary to disregard the corporate form for the limited purpose of assessing the affiliate's actual costs. The primary focus of the refund proceeding is ensuring that California customers receive appropriate refunds. It would defeat the purpose of the [mitigated market clearing price] refund methodology to allow sellers to rake in unjust and unreasonable costs "through the back door" of the cost filing process. That is exactly what would occur if sellers were to recover costs from affiliate transactions that were based wholly or in part on the very market-based/index-based rates the Commission is trying to remedy. We cannot allow sellers to collect inflated market prices and avoid the Commission's application of the [mitigated market clearing price] by shielding its overall corporate revenue position in affiliate contracts.

California Refund Rehearing Order, 127 FERC ¶ 61,269 at P 221 (citations omitted).

[193] Direct Energy, Integrys, and Quest Request for Rehearing at 17 (citing California Refund Rehearing Order, 127 FERC ¶ 61,269 at P 222).

F. Zonal and Subzonal Allocations

1. Order on Initial Decision

122. In the Order on Initial Decision, the Commission affirmed for a second time the proposed subzonal SECA charges, subject to specific adjustments directed therein, and reversed the Initial Decision on this issue.[194]

123. The Order on Initial Decision found that using North American Electric Reliability Corporation tag data to trace specific transactions during the test period and using that information to create subzones *was* a process that considered the benefits that accrue to loads in a subzone due to the elimination of regional through-and-out rates. It found that, if energy that was delivered to a subzone during the test period was charged a regional through-and-out rate, then it was reasonable to find that load in that subzone received a benefit due to the elimination of regional through-and-out rates. As the Commission discussed in the Order on Initial Decision, transmission owners made various adjustments to the SECA subzone allocations to recognize, for example, known and measurable differences, but the use of North American Electric Reliability Corporation tag data as the baseline was an appropriate, albeit imperfect, methodology to align those that received benefits due to the elimination of regional through-and-out rates with those that paid the SECA.

124. The Commission also found that the Initial Decision erred in concluding that subzones punish AEP's retail choice customers who decided to contract with alternative suppliers in 2002 and 2003.[195] The Commission found that assigning a SECA charge to customers whose load was served by transactions that were assessed regional through-and-out rates during the test period was not a punishment. It merely recognized that those customers caused some revenue to be lost because they were served by transactions that no longer paid the regional through-and-out rate.

125. The Commission recognized that no methodology would perfectly align those that benefit due to the elimination of regional through-and-out rates with those that paid the SECA. No matter what methodology was used, adjustments would need to be made to

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[194] In the July 2003 Order, the Commission first required SECA charges on a subzonal basis. July 2003 Order, 104 FERC ¶ 61,105 at P 54. The Commission affirmed this finding in the November 2003 Rehearing Order. November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 85.

[195] Order on Initial Decision, 131 FERC ¶ 61,173 at P 269 (citing Initial Decision, 116 FERC ¶ 63,030 at P 307).

make the allocation as accurate as possible under the circumstances. The Commission found that using North American Electric Reliability Corporation tag data where possible, and a load-ratio share where such tag data did not work, was a reasonable compromise and one that was reasonably consistent with cost-causation principles.

2. Requests for Rehearing

126. Direct Energy, Integrys, and Quest, Constellation, Green Mountain, and Ormet request rehearing of the Commission's decision to allow the SECA to be charged on a subzonal basis.

127. Green Mountain calls unsupported and incorrect the statement in the Order on Initial Decision that using North American Electric Reliability Corporation tag data "is a process that considers the benefits that accrue to loads in a subzone due to the elimination of regional through-and-out rates."[196] Green Mountain claims that the North American Electric Reliability Corporation tag data shows only what transactions occurred during 2002 and 2003 involving contract paths that terminated with deliveries to Green Mountain but provided no data whatsoever regarding what benefits, if any, accrued to the same load during the period from December 2004 onward.[197] Thus, according to Green Mountain, the use of North American Electric Reliability Corporation tag data to allocate transmission charges – indeed, as the sole allocator of such charges – violates the principle that all rates must, to some extent, reflect cost causation.[198]

128. Constellation argues that, contrary to the Commission's claim, the subzone allocation does not more closely align the benefits of eliminating rate pancaking with the customers responsible for the associated lost revenues. Constellation claims that the Commission found that all load-serving entities benefited equally due to the elimination of regional through-and-out rates because of the downward pressure put on prices for generation regardless of whether they sourced power locally or remotely during the transition period. Constellation argues that, by using subzones, a load-serving entity with retail choice that elected to obtain its power remotely during the test period pays a significantly higher SECA rate than a load-serving entity that obtained its power locally. Therefore, according to Constellation, a subzone allocation imposes significant differences in SECA charges for similarly-situated load-serving entities, which is unduly

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[196] Green Mountain Request for Rehearing at 14 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 267 (emphasis omitted)).

[197] *Id*.

[198] *Id.* at 12 (citing *K N Energy, Inc. v. FERC*, 968 F.2d 1295 (D.C. Cir. 1992)).

discriminatory and preferential. In addition, Constellation argues that, due to the lack of connection between a load-serving entity's choices regarding how it sourced power during the test period and the benefits that accrue equally to all load-serving entities due to the elimination of regional through-and-out rates during the transition period, the subzone allocation of SECA rates violates the principle of cost causation.[199]

129. With respect to the Commission's ordering of adjustments to the subzonal SECA charges for load-serving entities that experienced reductions in load since the test period, Constellation takes issue with the Commission's finding that, by making these adjustments, it was unnecessary to eliminate the use of the proposed subzonal SECA charges for all load-serving entities in order to ensure just and reasonable SECA charges. According to Constellation, this is "cold comfort" to the numerous load-serving entities that were not granted individual relief by the Commission.[200]

130. Direct Energy, Integrys, and Quest argue that a uniform charge would better align those that benefited from the elimination of the regional through-and-out rates with those that paid the SECA than the overly complex, patched-up subzone method proposed by the transmission owners. They claim that locational marginal price market structures in Midwest ISO and PJM provide the benefits of the elimination of through-and-out rates – lower prices for imported power – to all load-serving entities in the Midwest ISO or PJM regions, in proportion to the load-serving entity's loads. Direct Energy, Integrys, and Quest assert that a uniform charge is more reflective of cost-causation principles than the subzone allocation imposed by the Commission and of the benefits accruing to all participants in the markets, and it would, therefore, yield a just and reasonable result. In addition, they argue that, in accepting a subzonal allocation, the Commission ignored evidence showing that the subzonal allocation punished retail load-serving entities.[201] Direct Energy, Integrys, and Quest also state that the prior Commission orders imposing subzones that the Commission relies upon in the Order on Initial Decision as a justification for requiring subzones were, until May 21, 2010, pending on rehearing and remain subject to judicial review.

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[199] Constellation Request for Rehearing at 38-39.

[200] Constellation Request for Rehearing at 35-36.

[201] Direct Energy, Integrys, and Quest Request for Rehearing at 24. More specifically, they argue that a subzonal allocation punished retail load-serving entities because they: (1) imported disproportionately more energy than incumbent utilities; (2) were never on notice that they would be subject to charges based on activities from the past; and (3) did not have recovery mechanisms to collect these charges from current customers based on past practices. *Id*.

131. Ormet argues that allocating the SECA charges to subzones based on transactions during the test period but failing to make adjustments for known and measurable differences during the transition period constitutes retroactive ratemaking.[202] Ormet also claims that the Commission's logic for upholding subzones is contradicted by the logic that the Commission used for declining to treat the expiration of contracts as a known and measurable difference. Ormet explains that, when addressing subzones, the Commission stated that using North American Electric Reliability Corporation tag data to trace specific transactions during the test period and using that information to create subzones is a process that considers the benefits that accrue to loads in a subzone due to the elimination of regional through-and-out rates;[203] however, with regard to the expiration of existing contracts, the Commission reasoned that contract expiration should not be viewed as a known and measurable difference because, even though the load may no longer be importing power, it still benefits from an overall reduction in power rates.[204]

3. Commission Determination

132. We disagree with the rehearing requests arguing that the Commission in the Order on Initial Decision should have overturned its prior determination that the SECA should be charged on a subzonal basis.

133. Contrary to Green Mountain's claims, we continue to find that using North American Electric Reliability Corporation tag data is a process that considers the benefits that accrue to loads in a subzone due to the elimination of through-and-out rates. As Green Mountain acknowledges, the North American Electric Reliability Corporation tag data shows what transactions occurred during 2002 and 2003 involving contract paths that terminated with deliveries to Green Mountain.[205] It is reasonable, for the purpose of assigning responsibility to pay for lost revenues during the transition period, to use data from the test period to make a baseline estimate of which load-serving entities previously received deliveries of power transmitted using regional through-and-out service and thus received a quantifiable benefit from the elimination of the regional through-and-out rate. All load-serving entities, including Green Mountain, then had ample opportunity to show that known and measurable differences occurred and that those differences caused them not to benefit due to the elimination of regional through-and-out rates. Indeed, the

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[202] Ormet Request for Rehearing at 18.

[203] *Id.* at 16 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 267).

[204] *Id.* at 16-17 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 321).

[205] Green Mountain Request for Rehearing at 14.

Commission found that the SECA charges assigned to the Green Mountain subzone should be reduced because Green Mountain demonstrated that it had served no load in Midwest ISO between January 2006 and March 2006.[206] Furthermore, the Commission has explained the specific benefits that customers serving load in the combined region will receive due to the elimination of regional through-and-out rates.[207]

134. In addition, we reject Green Mountain and Constellation's argument that charging the SECA on a subzonal basis violates the principle of cost causation. The Commission addressed the same argument in the May 2010 Rehearing Order, where it rejected claims that the SECA does not properly align costs with benefits.[208] In addition, the Commission in the Order on Initial Decision affirmed that the use of North American Electric Reliability Corporation tag data when calculating the SECA charges was appropriate and consistent with previous Commission directives.[209] The parties raise the same issues here, and we reject them for the same reasons provided in the May 2010 Rehearing Order and the Order on Initial Decision. Additionally, we find that these arguments are a collateral attack on the July 2003 Order and the November 2003 Rehearing Order and were not within the scope of the SECA hearing at issue here.

135. We also find incorrect Constellation's claim that the Commission found in the Order on Initial Decision that all load-serving entities benefited equally due to the elimination of regional through-and-out rates. The Commission found that the elimination of regional through-and-out rates will put downward pressure on market prices,[210] but it did not find that all of the benefits would accrue equally to all of the parties. Further, contrary to Constellation's claim, a retail supplier that obtained its energy remotely during the test period is not automatically, for purposes of the SECA, similarly situated to a retail supplier that obtained its energy locally, and treating them differently does not result in undue discrimination. There may be other reasons that a customer-specific SECA adjustment is appropriate, but it is reasonable to find, as a starting point, that the two retail suppliers are not similarly situated for purposes of the

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[206] Order on Initial Decision, 131 FERC ¶ 61,173 at P 328.

[207] *See*, *e.g.*, *id.* P 229 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45); *accord* May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85.

[208] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85-87.

[209] Order on Initial Decision, 131 FERC ¶ 61,173 at P 160.

[210] *See*, *e.g.*, *id.* P 229 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

SECA if one obtained its energy remotely and thus paid regional through-and-out rates during the test period and one did not.[211]

136. We also reject Direct Energy, Integrys, and Quest's argument on rehearing that the SECA should be a uniform charge. The Commission addressed the same argument in the May 2010 Rehearing Order, explaining that the Commission could not find that the benefits due to the elimination of regional through-and-out rates will be spread uniformly among all load in the combined region.[212] Direct Energy, Integrys, and Quest raise the same issues here, and we reject them for the same reasons provided in the May 2010 Rehearing Order. The Commission also rejected in the Order on Initial Decision the claim that Direct Energy, Integrys, and Quest make on rehearing that subzones punish retail choice customers that choose alternate suppliers,[213] but they present no argument or evidence that causes us to alter that view. We also find unconvincing their apparent belief that, because the Commission's prior orders were pending rehearing and are subject to judicial review, the Commission should not place any weight on the finding in those orders that subzones are appropriate. That a prior order may be subject to a potential change on rehearing or upon court review does not mean that the Commission

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[211] *See* May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85 ("[B]ased on the record in this proceeding, it is not possible to precisely identify all of the benefits associated with the elimination of rate pancaking and how those benefits will be distributed; no methodology has been proposed that precisely assesses such benefits, nor is it likely that such benefits could be identified and quantified with precision. However, some entities will benefit more than others, particularly those loads that were served with through-and-out service at pancaked rates, who now will benefit from decreased transmission costs for existing import levels and can be expected to benefit from increased imports as such imports will become even more economic due to the elimination of rate pancaking. In this situation, allocating lost revenues to load in proportion to through-and-out service used to serve that load under pancaked rates, as the SECA transitional lost revenue recovery methodology does, is a reasonable approach to mitigating cost-shifting during the transition period because it allocates costs in proportion to the benefits that can reasonably be identified.").

[212] *Id*. P 88.

[213] Order on Initial Decision, 131 FERC ¶ 61,173 at P 269.

must ignore the findings in that order or that the findings in that order are without merit; to the contrary, the orders remain effective until actually changed or overturned.[214]

137. Direct Energy, Integrys, and Quest and Ormet also argue on rehearing that the SECA should not be charged on a subzonal basis because parties were not on notice that they would be subject to charges based on the actions they took during the test period. Although brought up here in the context of subzones, this is the same retroactive ratemaking argument that the Commission rejected in the Order on Initial Decision as outside of the scope of the hearing,[215] and we make the same finding here. Whether the SECA violates retroactive ratemaking or filed rate principles was an issue before the Commission on rehearing and was addressed in the May 2010 Rehearing Order.[216]

138. We also find unpersuasive Ormet's claim that the finding that using North American Electric Reliability Corporation tag data to create subzones is a process that considers the benefits that accrue to loads in a subzone[217] conflicts with the finding that, because the elimination of regional through-and-out rates will put downward pressure on market prices, contract termination does not by itself merit a customer-specific SECA adjustment.[218] As we note above, the benefit of the downward pressure on market prices caused by the elimination of through-and-out rates may be spread broadly, but that does not mean it is spread equally throughout the region. In addition, while the Commission may have rejected some customer-specific SECA adjustments, it did accept many others, including a reduction in Ormet's monthly SECA obligation to reflect a change in Ormet's load during the transition period.[219] The rejection of some customer-specific adjustments does not make invalid the logic that supports a finding that customer-specific North American Electric Reliability Corporation tag data is an appropriate, if imperfect, methodology to align those that received benefits due to the elimination of regional

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[214] 16 U.S.C. § 825*l*(c) (2006) (requests for rehearing and appeals do not stay Commission orders); 18 C.F.R. § 385.713(e) (2011) (requests for rehearing do not stay Commission orders).

[215] *Id*. P 489.

[216] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 126-49.

[217] Order on Initial Decision, 131 FERC ¶ 61,173 at P 267.

[218] *Id*. P 321.

[219] *Id*. P 325.

through-and-out rates with those that pay the SECA.[220] Moreover, if Ormet were indeed correct, the Commission would have to allow a customer-specific SECA adjustment for *any* change in circumstance, even if that change did not impact the benefits received due to the elimination of rate pancaking.

G. Adjustments for Known and Measurable Differences and General and Specific Summary Dispositions

1. Order on Initial Decision

139. In the Order on Initial Decision, the Commission reversed the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision with regard to the finding that contracts terminating prior to the transition period are not SECA eligible.[221] In addition, the Commission affirmed, in part, and reversed, in part, the findings in the Initial Decision with respect to certain discrete claims that test-period load is not reflective of load served during the transition period, and thus, SECA obligations should be adjusted accordingly.

140. Specifically, the Commission found that the findings in the March 10 Partial Decision, April 13 Partial Decision and Initial Decision that contracts that do not extend into the transition period should not serve as the basis of SECA charges misperceives the Commission's directives regarding the establishment of SECA charges.[222] The Commission stated that the "fundamental flaw in this finding is that it improperly transforms the SECA into a transactional charge, when the Commission's prior orders established the SECA as a load-based charge that does not depend on whether an entity transacts across the boundaries that were previously subject to transactional rates resulting in rate pancaking."[223] The Commission found that, based on the November 2003 Rehearing Order, "[t]he SECA is designed to collect revenue from each zone, or [subzone], in proportion to the benefits that the load within the zone, or [subzone], will realize when it no longer has to pay pancaked rates for transmission purchased from transmission owners in the other RTO to serve its load."[224] Moreover, the Commission stated that, in the November 2003 Rehearing Order, it rejected a proposal to rely on

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[220] *Id.* P 267; *see supra* note 246.

[221] *Id.* P 319.

[222] *Id.* P 320.

[223] *Id*.

[224] *Id*. (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 85).

actual usage, stating that doing so would "essentially convert the SECA back into a transactional charge for [through-and-out] service, thus recreating the impacts of rate pancaking which we are eliminating."[225]

141. Furthermore, the Commission stated that the framework for the SECA charges is that the charges are to be established based upon load during the test period,[226] subject to known and measurable changes.[227] The Commission stated that load-serving entities are assigned a SECA obligation based on test-period imports that utilized through-and-out service, unless such entities can demonstrate that known and measurable changes have occurred such that they do not benefit due to the elimination of rate pancaking. In addition, the Commission stated that whether an entity engages in transactions during the transition period that cross the boundaries that were previously subject to rate pancaking is not dispositive as to whether the entity benefits due to the elimination of regional through-and-out rates. Importantly, the Commission stated that "few transactions that were active during the test period had terms long enough to extend into the transition period; they would instead likely be replaced by new transactions at beneficial prices reflecting the downward pressure on market prices where the importing load is located due to the elimination of regional through-and-out rates, thereby benefiting due to the elimination of regional through-and-out rates."[228]

142. However, the Commission did affirm findings in the Initial Decision, though under different reasoning, that certain parties' SECA obligations should be adjusted to reflect reductions in load served between the test period and the transition period.[229] The Commission stated that, unlike load-serving entities claiming that contracts terminated prior to the transition period and are, thus, not SECA eligible, adjustments to SECA obligations are appropriate for load-serving entities with reduced load during the transition period to accurately align the benefits realized due to the elimination of regional through-and-out rates to the level of load served during the transition period.

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[225] *Id*. (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 64 n.117).

[226] *Id*. P 321 (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66).

[227] *Id*. (citing November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 61; July 2003 Order, 104 FERC ¶ 61,105 at P 54).

[228] *Id*.

[229] *Id*. P 324.

The Commission found that, where the load served by the load-serving entity during the transition period has been reduced since the test period or is no longer served by the load-serving entity during the transition period, it is reasonable to conclude that the load-serving entity will not benefit due to the elimination of regional through-and-out rates for the load no longer served. Therefore, the Commission required the SECA obligations of certain parties to be adjusted.

143. First, regarding Quest's SECA obligation associated with deliveries to Northern Ohio Aggregation Coalition under a Power Purchase Agreement with AEP Energy Marketing (AEM) and with deliveries to North Star Steel (North Star), the Commission found that Quest did not serve these loads during the transition period, and thus Quest's SECA obligation should be adjusted to reflect the load-serving entity that replaced Quest as the supplier to such loads and that should be responsible for the SECA charges applicable to such loads.[230] However, the Commission stated that, rather than shifting the Quest SECA obligations for such loads to the new supplier, the new suppliers should pay the generally applicable zonal SECA charge, applicable to entities without subzone obligations, under section II.B of Schedule 22 of the Midwest ISO tariff, for the newly acquired load.

144. Second, regarding CMS Energy, the Commission found that its SECA obligation should be adjusted to reflect that it did not serve retail load at the MECS.DECO.CMSZ sink since September 2003.[231] The Commission stated that no party disputed CMS Energy's claim that it had not served retail load at that sink since September 2003. Thus, the Commission required that the entity newly taking transmission service to serve this load during the transition period should pay the generally applicable zonal SECA charge under Schedule 22 of the Midwest ISO tariff for the newly acquired load.

145. Third, with regard to Green Mountain, the Commission found that its SECA obligation should be adjusted to reflect that Green Mountain served no load in Midwest ISO between January 2006 and March 2006.[232] The Commission stated that the entity that took transmission service under the Midwest ISO tariff during the transition period to serve the load in the Green Mountain subzone on behalf of Green Mountain should pay the Green Mountain subzone SECA. Thus, the Commission found that the entity newly taking transmission service in January 2006 to serve this load during the remainder of the

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[230] *Id*. P 326.

[231] *Id*. P 327.

[232] *Id*. P 328.

transition period should pay the generally applicable zonal SECA charge under Schedule 22 of the Midwest ISO tariff.

2. Requests for Rehearing

146. BG&E requests rehearing of the Commission's finding that contracts terminating prior to the transition period are not excluded from the calculation of SECA charges. BG&E argues that, if the SECA is not retroactive, cancelled transactions must be excluded. In addition, BG&E argues that through-and out transactions that occurred during the test periods but ended prior to the commencement of the transition period must be removed as part of routine test period adjustments required by Commission practice. Moreover, BG&E argues that, since these transactions were terminated, they would not produce revenues if regional through-and-out rates were still in place throughout the combined region. Therefore, BG&E argues that there is no basis for terminated contracts to be collected in the SECA charges.[233]

147. For example, BG&E states that, in order that the SECA not result in the over-recovery of lost revenues, it should exclude charges for revenues that would not otherwise have been collected even if regional through-and-out rates had remained in effect because the contract itself expired under it own terms.[234] BG&E states that the Order on Initial Decision instead reversed the finding in the Initial Decision that contracts terminating prior to the transition period are not SECA eligible.[235] BG&E states that the reason given is that "[w]hether an entity engages in transactions during the transition period . . . is not dispositive as to whether the entity benefits due to the elimination of regional through-and-out rates."[236] BG&E argues that this statement suggests that the SECA can be charged for a benefit even if it results in a collection of more than lost revenues. Moreover, BG&E argues that, in return for the "benefit" of no longer having to pay an unjust and unreasonable regional through-and-out rate, the customer must pay a SECA if tag data shows that a transaction with a regional through-and-out rate was provided to that customer (or, more precisely, provided to a customer in the rate zone where the current customer resides) during the test period.[237]

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[233] BG&E Request for Rehearing at 5.

[234] *Id*. at 35.

[235] *Id*. (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 319).

[236] *Id*. (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 321).

[237] *Id*. at 36.

148. BG&E argues that, since the regional through-and-out transactions are continuing beyond the two test periods, but the regional through-and-out rates are not continuing beyond the two test periods, it is necessary to forecast the extent to which through-and-out transactions that occurred during the test period will continue in order to place a SECA charge on those continuing transactions. BG&E argues that this is what the Commission had in mind when it stated that the SECA filings must include "adjustments for known and measurable differences, to most closely reflect future trading patterns."[238]

149. BG&E states that the problem is that one cannot just look at the historical test year data to determine what regional through-and-out rates were paid and then be assured that each regional through-and-out rate dollar is now lost revenue created by the elimination of regional through-and-out rates effective December 1, 2004.[239] BG&E maintains that any such assumption ignores the fact that many of these regional through-and-out payments would have gone away by that date anyway due to the non-renewal of contracts that were in effect during the test period but that have since expired. It claims that tracking down the contracts associated with every reservation during the test period to determine whether the contract had come to an end without any further regional through-and-out rate obligation irrespective of the elimination of regional through-and-out rates is a necessary task in order to accurately quantify lost revenues. BG&E asserts, however, that this task has not been undertaken, or even recognized, by the SECA filers, and the Commission has erroneously decided to just let it go.[240]

150. BG&E argues that the SECA rate is not just and reasonable because it fails to exclude expired contracts for through-and-out transactions.[241] BG&E states that, if all through-and-out transactions ended simultaneously when regional through-and-out rates ended, there would be no lost revenue and, hence, no SECA. According to BG&E, it is only because some transactions continued that a SECA was to be implemented. Therefore, BG&E argues that the inclusion of expired transactions in the SECA defies logic and violates the test period approach of ratemaking whereby atypical and extraordinary events occurring within a test period, as well as events occurring within a

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[238] *Id*. (citing July 2003 Order, 104 FERC ¶ 61,105 at P 54).

[239] *Id*. at 37.

[240] *Id*.

[241] *Id*. at 41.

test period that are not expected to recur, are to be removed before setting rates for a future period.[242]

151. Indeed, BG&E asserts that Commission case law has for a considerable time been clear that test period costs should only be included in the cost of service if they reflect typical and recurring events. For example, BG&E states that Opinion No. 783-A holds that a regulated entity "has a particular responsibility to . . . substantiate . . . typicality not only for the test period but also for the projected effective term of the tendered rates."[243] BG&E argues that, not only have the SECA filings made no such "typicality" showing, they have purposefully included every transaction occurring within the test periods regardless of whether the transactions continued beyond the test period, thereby insuring the inclusion of costs that are non-recurring. BG&E maintains that the Commission would not have required the use of the test period approach if it had intended that test period principles of ratemaking were to be ignored as they have been here. BG&E states that known and measurable changes in the form of expired contracts have not been factored into the test period approach as required by the Commission's regulations and its previous orders.

152. Green Mountain argues that the adjustments for reduced load are not sufficient to meet the requirement that rates should match, as closely as practicable, the costs to serve each class or individual customer. Green Mountain argues that the SECA charged to a subzone will not reflect changes to suppliers, load factor, reservation levels, implementation of demand response programs, commissioning or decommissioning of generating units, or the numerous other factors that might have changed import patterns between 2002 and 2006.[244]

153. AEP, Dayton, and Exelon request clarification or, in the alternative, rehearing to ensure that the required SECA adjustments regarding CMS Energy's, Green Mountain's, and Quest's subzonal SECA obligations properly conform to the Commission's stated goal of ensuring that the SECAs are calculated and assessed in ways that hold transmission owners revenue neutral. AEP, Dayton, and Exelon argue that, rather than shifting a portion of the SECA charges previously assessed to CMS Energy, Green Mountain, and Quest, the Order requires the "new supplier" to pay a zonal transmission charge. They claim that in each instance, however, the wording of the requirement was

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[242] *Id*. at 42.

[243] *Id.* at 43 (citing *Pub. Serv. Co. of Ind.*, 57 FPC 1173, 1182 (1977), *aff'd, Pub. Serv. Co. of Ind. v. FERC*, 575 F.2d 1204 (7th Cir. 1978)).

[244] Green Mountain Request for Rehearing at 18.

slightly different.[245] AEP, Dayton, and Exelon state that, since the reference to section II.B of Schedule 22 of the Midwest ISO tariff is only found in paragraph 326 addressing Quest, the Commission should clarify that section II.B is also to be used to calculate the SECA charges for the "new supplier" for CMS Energy and Green Mountain.

154. In addition, AEP, Dayton, and Exelon state that the SECA charges calculated under the section II.B of Schedule 22 of the Midwest ISO tariff would produce different SECA charges than those originally assessed to CMS Energy, Green Mountain, and Quest. As such, AEP, Dayton, and Exelon request that the Commission clarify and explain how the PJM transmission owners will be fully compensated by the new supplier, if any of the SECA charges calculated under Schedule II.B is less than that originally assessed to CMS Energy, Green Mountain, and Quest.

3. Commission Determination

155. We deny BG&E's challenge to the Commission's decision in the Order on Initial Decision to maintain terminated contracts in the SECA charges. We continue to believe that it is unreasonable to assume that contracts that terminated before or during the transition period were not replaced with contracts that benefited from continued use of through-and-out service. As the Order on Initial Decision stated, "few transactions that were active during the test period had terms long enough to extend into the transition period; they would instead likely be replaced by new transactions at beneficial prices reflecting the downward pressure on market prices where the importing load is located due to the elimination of regional through-and-out rates, thereby benefiting due to the elimination of regional through-and-out rates."[246] Moreover, carried to its logical conclusion, excluding expired contracts and including new contracts that were in effect during the transition period would "improperly transform the SECA into a transactional charge, when the Commission's prior orders established the SECA as a load-based charge that does not depend on whether an entity transacts across the boundaries that were previously subject to transactional rates resulting in rate pancaking."[247] Importantly, the Order on Initial Decision found that the Commission has never indicated that, if a contract terminated before the transition period, it would result in reduced SECA charges.[248]

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[245] AEP, Dayton, and Exelon Request for Rehearing at 16.

[246] Order on Initial Decision, 131 FERC ¶ 61,173 at P 321.

[247] *Id.* P 320.

[248] *Id.* P 321.

156. We also disagree with Green Mountain's claim that the adjustment is not sufficient to meet the requirement that rates should match, as closely as practicable, the costs to serve each class or individual customer. Why these adjustments are not sufficient and how insufficient they may be (including whether the differences are or are not significant), is not explained, and we are unwilling to change our conclusion based on unsubstantiated allegations. Green Mountain argues that to match costs to benefits the test period data muse be adjusted for numerous factors. Because Green Mountain failed to argue for these adjustments in the underlying hearing before the administrative law judge, it is barred from introducing them for the first time on rehearing of our Order on Initial Decision.[249] We are not willing to reopen the record and commence a new hearing in order to consider these late-supported allegations by Green Mountain.[250]

157. As to the use of section II.B of Schedule 22 of the Midwest ISO tariff, the Order on Initial Decision found that, in three instances (i.e., those of CMS Energy, Green Mountain, and Quest), the load-serving entities originally assessed the SECA charges did not serve the applicable load during at least some portion of the SECA transition period. The Commission determined that the load-serving entities' SECA obligations should be reduced accordingly, and the new supplier assessed the generally applicable zonal SECA charge under Schedule 22. However, in only one instance, involving the new supplier of the load formerly served by Quest, did the Commission expressly specify section II.B of Schedule 22 as containing the generally applicable zonal SECA charge. In fact, section II.B of Schedule 22 of the Midwest ISO tariff is the appropriate vehicle to calculate the SECA charges for each new supplier for the load formerly served by CMS Energy, Green Mountain, and Quest.

158. Finally, we will reject AEP, Dayton, and Exelon's request that the Commission clarify and explain how the PJM transmission owners will be fully compensated by the new supplier if any of the SECA charges calculated under section II.B of Schedule 22 of the Midwest ISO tariff is less than that originally assessed to CMS Energy, Green Mountain, and Quest. We find that the generally applicable zonal SECA charge under Schedule 22 of the Midwest ISO tariff reasonably reflects the through-and-out revenues that could be expected to be lost during the transition period for through-and-out service from new suppliers, who were not serving that load during the test period and thus could

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[249] *See Niagara Power Corp*., 96 FERC ¶ 61,011, at 61,044 (2001); *Baltimore Gas and Electric Co*., 92 FERC ¶ 61,043, at 61,114 (2000).

[250] *See generally W. Area Power Admin. v. FERC*, 525 F.3d 40, 43 (D.C. Cir 2008); *Consolidated Edison Co. of N.Y. v. FERC*, 315 F.3d 316, 325 (D.C. Cir. 2003); *Ill. Pub. Telcoms. Ass'n v. FCC*, 117 F. 3d 555, 565, *clarified on reh'g*, 123 F.3d 693 (D.C. Cir. 1997),

not have a subzonal SECA calculated for them. AEP, Dayton, and Exelon have not established how such reductions would result in under-recovery of revenues for through-and-out service. In the Order on Initial Decision, the Commission recognized that SECA revenues could be reduced to the extent that customers have supported adjustments for known and measurable differences, but found that such reductions could be offset by, for instance, increased revenues from other entities that continued to pay the regional through-and-out rates for existing transactions (i.e., reservations for requests for service made prior to November 17, 2003, for service commencing before April 1, 2004).[251]

H. Fixed Versus Per-Unit SECA charge

1. Order on Initial Decision

159. In the Order on Initial Decision, the Commission reversed the Initial Decision's rejection of the fixed subzonal SECA charges that were proposed in the compliance filings by Midwest ISO transmission owners and the PJM transmission owners. The Commission noted that, in their SECA compliance filings, the transmission owners in each RTO voluntarily designed their subzonal SECA charges as fixed charges that recover test-period revenues and do not vary with the level of the load-serving entity's load. The Commission agreed with the Initial Decision that such fixed charges would result in unjust and unreasonable charges if certain entities experienced reductions in the loads that they serve since the test periods and had not been given an opportunity to make adjustments. But, the Commission further determined:

> However, rather than order changes to all of the non-settled SECA charges to reflect a traditional usage charge, which as Midwest ISO [transmission owners] note, would generally result in increased charges for customers . . . we have ordered adjustments to the subzonal SECA charges for these entities to reflect their load reductions. In light of these adjustments, we find it unnecessary to eliminate the use of the proposed fixed subzonal SECA charges for all load-serving entities in order to ensure just and reasonable SECA charges.[[252]]

2. Requests for Rehearing

160. Ormet argues that the Commission's logic regarding load growth fails in light of its holding on subzones; if allowing billing based on subzones does not punish those

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[251] Order on Initial Decision, 131 FERC ¶ 61,173 at P 364.

[252] Order on Initial Decision, 131 FERC ¶ 61,173 at P 348.

going to retail competition because it simply reflects cost-causation, then allowing costs to be shifted from entities with decreased load to those with increased load similarly merely reflects that those entities with load growth are now imposing a greater cost on the system. Ormet further states that all data for the transition period are now known with certainty – the transmission owners have the ability to calculate the revenue requirement based on the test period and allocate those costs based on load in the transition period – so the allocation of the revenue requirement based on usage need not result in increased revenues for transmission owners. Ormet further argues that, at a minimum, traditional ratemaking should be applied to loads that decrease between the test period and the transition period because: (1) the customer would not have benefitted due to the elimination of rate pancaking during the test period, to the extent that its load decreased; and (2) the transmission owners would not have lost revenues from that customer due to the elimination of rate pancaking, to the extent that the customer's load decreased.[253] Ormet also argues that the utilization of traditional ratemaking principles (i.e., applying a test period rate to a transition period load) would satisfy the principle of cost causation.

161. Several parties also argue that the SECA charge violates the rule against retroactive ratemaking and the filed rate doctrine.[254] For example, BG&E argues that the resulting lost revenue allocations and rates are unjust and unreasonable because they retroactively apply fixed and unavoidable charges for past transactions that no longer exist. Direct Energy, Integrys, and Quest argue that the SECA charge is invalid because it is based on past actions where parties were not on notice and for which there was no rate in effect or on file.

3. Commission Determination

162. Regarding Ormet's arguments, although the SECA charge adopted by the Order on Initial Decision may not individually address every single customer's unique circumstances,[255] the Commission has noted that ordering changes to all non-settled SECA charges to reflect a traditional usage charge would generally result in increased charges for customers. Thus, we find it more appropriate to adopt an approach which will reduce the impact on customers generally.

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[253] Ormet Request for Rehearing at 19-20.

[254] BG&E Request for Rehearing at 50-60; Direct Energy, Integrys, and Quest Request for Rehearing at 27; Constellation Request for Rehearing at 36; Green Mountain Request for Rehearing at 18; Ormet Request for Rehearing at 20.

[255] In fact, it is not clear that the SECA charge needs to do so. *See supra* note 259.

163. With respect to the parties' arguments that the SECA charge constitutes retroactive ratemaking and violates the filed rate doctrine, the Commission addressed such arguments in the May 2010 Order on Rehearing. In that order, the Commission rejected arguments that the SECA charge constitutes retroactive ratemaking and violates the filed rate doctrine because it uses historical, test year data, without prior notice, to establish the SECA rate and charges.[256] The parties raise the same issues here, and we will deny rehearing for the same reasons that the Commission denied rehearing on those issues in the May 2010 Order on Rehearing.

I. Shift-to-Shipper Claims

164. In the November 2003 Rehearing Order, the Commission recognized that, in certain instances, the benefits of the elimination of regional through-and-out rates would not accrue to the load-serving entity but rather to the load-serving entity's shipper that had traditionally paid the charges for through-and-out service pursuant to the relevant contract for delivered power.[257] In addition to paying the SECA, load-serving entities with bundled delivery contracts extending into the transition period would also pay regional through-and-out rates, which remained embedded in the long-term contract price even after the elimination of these rates. To prevent this double payment, the Commission provided a "shift-to-shipper" mechanism, allowing a load-serving entity to shift its SECA liability to its shipper.[258] The Commission stated:

> [A]s part of the compliance filing process, we will allow [load-serving entities] 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 [load-serving entity's] load served by the contract.[[259]]

165. Several parties filed shift-to-shipper claims, many of which were subsequently settled. The Order on Initial Decision's findings and associated requests for rehearing – and our responses regarding the remaining shift-to-shipper claims – are discussed below.

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[256] *See* May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 126-49.

[257] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45.

[258] *Id*.

[259] *Id*. For convenience, this shift-to-shipper language will be referred to below as Paragraph 45.

1. Michigan South Central Power Agency's and Six Michigan Cities' Claims against CCG

a. Order on Initial Decision

166. The Order on Initial Decision affirmed the Initial Decision's separate findings that Michigan SCPA and Six Michigan Cities may each shift a portion of their SECA liability to CCG.[260] In doing so, the Order on Initial Decision rejected Constellation's argument that, to prevail on a shift-to-shipper claim, a load-serving entity must show that the supplier to whom it seeks to shift its SECA liability benefitted due to the elimination of through-and-out rates. The Order on Initial Decision stated:

> The Commission eliminated regional through-and-out rates in the hope of establishing a more efficient and competitive electricity market in the combined region. The fact that some parties (i.e., load-serving entities) may not realize those benefits by nature of their contracts is precisely the point of Paragraph 45 . . . . Paragraph 45 imposes no benefits test.[[261]]

167. Further, with specific regard to Michigan SCPA's shift-to-shipper claim against CCG, the Order on Initial Decision reversed the Initial Decision's reduction of the claim by 21.8 percent. The Commission stated:

> It is true that SECA amounts should be calculated based on test-period data with adjustments for known and measurable differences to most closely reflect future trading patterns. However, the Initial Decision assumes that, because Michigan SCPA simultaneously resold energy in 2005 while it purchased energy from CCG, it did not need the energy purchased from CCG to serve its load. That finding fails to acknowledge the factual record established in this proceeding, which demonstrates that Michigan SCPA's load exceeded its purchases from CCG during the transition period and that Michigan SCPA increased the output of its own plants in 2005, compared to their output in 2002, by more than the 57,354 MWh of power sold to third parties in 2005.[[262]]

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[260] Order on Initial Decision, 131 FERC ¶ 61,173 at P 375, 385.

[261] *Id.* P 376, 385.

[262] *Id.* P 378.

168. In rejecting Constellation's assertion that a greater reduction was required, the Order on Initial Decision stated:

> Constellation's position is largely based on the unpersuasive argument that, in 2005, Michigan SCPA's and CCG's purchases from other third party suppliers in PJM declined, and they purchased power instead from the Midwest ISO day-ahead and real-time energy markets. Michigan SCPA has a long-term, fixed price, fixed quantity contract with CCG, which is unaffected by any energy market changes, and indeed, the record reveals no substantial difference in the amount of power purchased from CCG that qualifies as a known and measurable change to test-period data.[[263]]

b. <u>Request for Rehearing</u>

169. On rehearing, Constellation maintains its position that, for purposes of shift-to-shipper claims, a load-serving entity should be required to show that the supplier to whom it seeks to shift its SECA liability benefitted due to the elimination of through-and-out rates. Constellation asserts that, in the Order on Initial Decision, the Commission "jettisoned its 'well-established principle of cost causation' which requires that 'costs should be allocated, where possible, to customers based on customer benefits and cost incurrence.'"[[264]] Constellation argues that the Commission ignored the principle of cost causation and thereby deviated from established precedent without a reasoned explanation. Furthermore, claims Constellation, by adhering to the principle of cost causation in imposing SECA charges on load-serving entities, but purportedly ignoring the same principle when addressing shift-to-shipper claims, the Order on Initial Decision is internally inconsistent

170. With regard to Michigan SCPA's claim, Constellation maintains that any of its SECA liability to Michigan SCPA should be reduced by at least the 21.8 percent supported by the Initial Decision. Constellation claims that the Commission's finding regarding Michigan SCPA's shift-to-shipper claim against CCG is inconsistent with its other findings regarding known and measurable changes during the transition period. Constellation states that the Order on Initial Decision accepted a reduction in the SECA liabilities of Old Dominion Electric Company (Old Dominion) because of a known and measurable change in the transition period; Old Dominion replaced an existing contract for delivered power that crossed a relevant seam with the output of its own new

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[263] *Id.* P 379.

[264] Constellation Request for Rehearing at 13 (*quoting Cal. Power Exchange Corp.*, 106 FERC ¶ 61,196, at P 17 (2004)).

generation plant located locally. Constellation recites the Commission's finding that "[b]ecause Old Dominion replaced the Ironwood contract with its own new generator located in the Dominion zone . . . it is reasonable to conclude that Old Dominion will not benefit due to the elimination of regional through-and-out rates for the load served from its new local generation . . . ."[265] Constellation argues that the Commission similarly should have found that Michigan SCPA did not benefit from the elimination of regional through-and-out rates to the extent that Michigan SCPA used the increased output of its own local generation to serve load during the transition period. Constellation argues that there is no material difference between the output of Old Dominion's new local generation and the increased output of Michigan SCPA's existing local generation. Constellation asserts that the Commission's treatment of the two situations was inconsistent and therefore unduly discriminatory.[266]

c. Commission Determination

171. We will deny Constellation's request for rehearing concerning shift-to-shipper claims. As to Constellation's continued call for a benefits test, we find that Constellation raises no arguments on rehearing that were not already considered and rejected in the Order on Initial Decision. In any case, as found in the Initial Decision, which the Commission affirmed on this issue, Constellation's argument that CCG received no benefit from the elimination of through-and-out rates is meritless. Regardless of where CCG obtained the power used to serve, for example, Michigan SCPA, CCG charged Michigan SCPA the contract price, which included the cost of transmission and incorporated the through-and-out rates that were in place when the contract was formed. CCG did not have to pay the regional through-and-out rate once it was eliminated, so CCG, and not Michigan SCPA, would benefit from the elimination of that rate under the contract.[267] While Paragraph 45 does not require a load-serving entity to show that the supplier to whom it seeks to shift its SECA liability benefitted from the elimination of through-and-out rates, it is clear that CCG was the entity in the position to benefit from the elimination of through-and-out rates under its contract with Michigan SCPA. Accordingly, Constellation's general theories as to why a benefits test should apply to shift-to-shipper claims do not support CCG's denial of SECA liability. Additionally, we find that Constellation's arguments are an improper collateral attack on the Commission's finding in Paragraph 45.

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[265] *Id.* at 20 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 323).

[266] *Id*.

[267] *See* Order on Initial Decision, 131 FERC ¶ 61,173 at P 432.

172. In addition, we are unconvinced by Constellation's attempt to reduce CCG's SECA liability by drawing a parallel between Michigan SCPA's and Old Dominion's respective situations. The record reveals that Michigan SCPA is not similarly situated to Old Dominion. In the Order on Initial Decision, the Commission found that Old Dominion demonstrated that it built a new 500 megwatt (MW) combustion turbine plant within the Dominion zone to replace an expired contract for 490 MW of firm power that it previously imported from PJM, and it will thus likely no longer purchase across the PJM-Dominion seam to serve load.[268] In contrast, as noted in the Order on Initial Decision, Michigan SCPA has a long-term, fixed price, fixed quantity contract with CCG, and the record reveals no substantial difference in the amount of power purchased from CCG that qualifies as a known and measurable change to test-period data.

2. CCG's Claim against AEM

a. Order on Initial Decision

173. The Order on Initial Decision reversed the Initial Decision's finding that CCG may shift a portion of its SECA liability to AEP. In doing so, the Commission rejected the Initial Decision's allowance of "ripple claims," whereby a shipper on the receiving end of a shift-to-shipper claim (in this case, CCG) would have been allowed to shift its SECA liability to an upstream supplier (in this case, AEM) that supposedly benefitted due to the elimination of through-and-out rates. Reciting Paragraph 45's requirement that shift-to-shipper claims be brought by load-serving entities, and noting the lack of a requirement that a load-serving entity must satisfy a benefits test, the Order on Initial Decision stated that ripple claims have no basis in Paragraph 45.[269]

b. Request for Rehearing

174. On rehearing, Constellation argues that the Order on Initial Decision's limitation of shift-to-shipper claims to load-serving entities and denial of ripple claims brought by their wholesale suppliers is unduly discriminatory and preferential. Constellation asserts that, by permitting load-serving entities to make shift-to-shipper claims, the Commission recognized that some parties that had entered into long-term agreements with wholesale suppliers do not benefit from the elimination of rate-pancaking because they have no choice but to continue to purchase the power from that supplier and, thus, cannot enjoy the benefit of choosing a new supplier that may be more economical due to the

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[268] *Id.* P 323.

[269] *Id.* P 393.

elimination of regional through-and-out rates.[270] Constellation contends that, as a wholesale supplier, it is in precisely the same position as the load-serving entities in this respect: by entering into a long-term, fixed-price contract for bundled power supply with AEP, CCG had no choice but to continue to purchase power from AEP and, thus, could not enjoy the benefit of choosing a new supplier that may be more economical due to the elimination of rate pancaking. Constellation concludes that, as CCG and load-serving entities are similarly situated, the Commission's allowance of shift-to-shipper claims for load-serving entities, but denial of ripple claims by their suppliers, was unduly discriminatory and preferential.

c. Commission Determination

175. We will deny Constellation's request for rehearing on this issue. As the Commission explained in the Order on Initial Decision, "Paragraph 45 [of the November 2003 Rehearing Order] speaks of load-serving entities making shift-to-shipper claims, and CCG is not a load-serving entity. Hence such claims are not available to CCG either as a defense or to shift liability to AEM. In short, in Paragraph 45 the Commission did not provide for ripple claims but rather explicitly allowed for claims by load-serving entities."[271] Neither CCG, nor any other party, sought rehearing of the November 2003 Rehearing Order or the other orders adopting the SECA mechanism, to seek to expand the shift-to-shipper adjustment provided in Paragraph 45 to include ripple claims, and we will not entertain here what essentially constitutes an untimely request for rehearing and an improper collateral attack of those orders.[272]

3. Quest's Claim against MAEM

a. Order on Initial Decision

176. In a reversal of the Initial Decision, the Order on Initial Decision determined that no contract existed between Quest and MAEM which would provide the basis for a shift-to-shipper claim by Quest against MAEM. The Order on Initial Decision disagreed with

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[270] Constellation Request for Rehearing at 16 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 376 n.466).

[271] Order on Initial Decision, 131 FERC ¶ 61,173 at P 393.

[272] The Commission disfavors belated claims and arguments, such as parties raising entirely new arguments on rehearing. *See Niagara Power Corp*., 96 FERC ¶ 61,011 (2001); *Baltimore Gas and Electric Co*., 92 FERC ¶ 61,043 (2000); *see also* Pacific Gas & Electric v. FERC, 533 F.3d 820, 825 (D.C. Cir 2005).

the Initial Decision's finding that a *de facto* contract existed between Quest and MAEM through the lineage of a power contract establishing a relationship between MAEM and WPS Energy Services, Inc. (WPS Energy) and a credit contract establishing a relationship between WPS Energy and Quest. The Order on Initial Decision stated:

> It is undisputed that there was no bilateral contract between Quest and MAEM, and in the absence of such an agreement, MAEM cannot be liable for a shift-to-shipper claim. We are also not persuaded that a binding contract existed merely because a contract existed between Quest and WPS Energy. We find no case, and the Initial Decision cites none, permitting our reliance on a so-called contract.[[273]] While it is settled law that a binding contract may be oral or implied, rather than expressed in writing,[[274]] the fundamental elements of such a contract (such as offer, acceptance, and consideration) are not evidenced here.[[275]]

b. <u>Request for Rehearing</u>

177. On rehearing, Direct Energy, Integrys, and Quest reiterate the argument that Quest had some type of quasi-contract with MAEM, either based on a "three way contractual arrangement [that] is common in the electric industry" (in this case, a contract between MAEM and WPS Energy and a contract between WPS Energy and Quest),[[276]] or based on the theory of unjust enrichment, arguing that there was a benefit conferred, appreciation or knowledge of benefit by the recipient, and acceptance or retention of the benefit such that it would be inequitable for the recipient to retain the benefit without payment.[[277]]

178. Direct Energy, Integrys, and Quest further argue that the Order on Initial Decision's denial of Quest's claim against MAEM is inconsistent with allowing transmission owners to collect the SECA from BP Energy, the supplier in the BP Energy-

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[[273]] Without defining a *de facto* contract, the Initial Decision had found that a *de facto* contract existed between Quest and MAEM due to: (1) a power contract establishing a relationship between WPS Energy and MAEM; and (2) a credit contract establishing a relationship between WPS Energy and Quest. *See* Order on Initial Decision, 131 FERC ¶ 61,173 at P 512.

[[274]] Restatement (Second) of Contracts, § 4 (1981).

[[275]] Order on Initial Decision, 131 FERC ¶ 61,173 at P 400.

[[276]] Direct Energy, Integrys, and Quest Request for Rehearing at 21-22.

[[277]] *Id.* at 22.

Green Mountain transaction. They assert that the factual situations are nearly identical, and the party that paid the through-and-out rate (i.e., both BP Energy and MAEM) should be responsible for the SECA.[278]

c. Commission Determination

179. We will deny Direct Energy, Integrys, and Quest's request for rehearing on this issue. As to their arguments concerning the existence of some type of quasi-contract permitting a shift-to-shipper claim, we find that they raise no arguments on rehearing that were not substantively addressed in the Order on Initial Decision. As stated in the Order on Initial Decision, we find no case, and neither the Initial Decision nor Direct Energy, Integrys, and Quest cites one, stating that a binding contract may be found to exist between two parties based upon separate contracts that each party entered into with a third party. To shift its SECA charges to MAEM, Quest in this proceeding had the burden to show that it had existing fixed price contracts with MAEM for bundled supply that continued into the transition period. This is a high threshold (and one that Quest did not meet) when there is no written contract for power supply between Quest and MAEM.

180. Having already lost once specifically on their quasi-contract theory, Direct Energy, Integrys, and Quest reiterate the alternate argument that a contract existed between Quest and MAEM based upon the theory of unjust enrichment. Direct Energy, Integrys, and Quest fail, however, to state exactly what type of benefit Quest conferred to MAEM in this case. Without explicitly ruling on Quest's unjust enrichment argument, the Initial Decision noted that the benefit that MAEM received is the elimination of through-and-out rates.[279] But such a benefit was not conferred on MAEM by Quest, and we are aware of no case (and, again, Direct Energy, Integrys, and Quest cite none) allowing a party to prevail on a claim of unjust enrichment where it was not the party that did the enriching. In addition, Direct Energy, Integrys, and Quest's relationship is not similar to BP and Green Mountain's where a single contract existed and defined the relationship between the two parties. In any event, the issue as to who should pay the Green Mountain subzonal SECA is different, and did not depend on the contract between BP and Green Mountain, because there is no shift-to-shipper claim associated with that contract. Instead, the issue concerned which party took service from Midwest ISO for delivery to load in the Green Mountain subzone and thus should pay the SECA surcharge to the license plate zonal rates for that service.

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[278] *Id.* at 21.

[279] *See* Order on Initial Decision, 131 FERC ¶ 61,173 at P 477.

4. CCG's Claim against CMS Energy and Bay City's Claim against CMS Energy

a. Order on Initial Decision

181. Noting the Initial Decision's finding that neither CCG nor Bay City may shift SECA liability to CMS Energy, and that no party filed a brief concerning this issue, the Order on Initial Decision summarily affirmed the Initial Decision on this point.[280]

b. Request for Rehearing

182. On rehearing, Constellation argues that its brief on exceptions to the Initial Decision indeed addressed CCG's claim against CMS Energy.[281] Constellation reiterates its argument, as set forth in its brief, that Bay City, one of Six Michigan Cities' parties, should not be allowed to shift its SECA liability to CCG. Constellation contends, contrary to the Initial Decision and Order on Initial Decision, that it was CMS Energy, not CCG, that had a contractual relationship with Bay City for the sale of delivered power, and the assignment of that contract to CCG was inconsequential for the purposes of Bay City's shift-to-shipper claim against CCG.[282]

c. Commission Determination

183. We are not persuaded by Constellation's arguments concerning this issue. Constellation's arguments on rehearing conflate its claim against CMS Energy with Bay City's claim against CCG. Largely rejecting all of Constellation's arguments on this point, which Constellation posited at the hearing stage and reiterated in its brief on exceptions, the Initial Decision found that Bay City, as one of the Six Michigan Cities, may shift its SECA liability to CCG. The Order on Initial Decision affirmed that finding, and as noted above in the section discussing Six Michigan Cities' claim against CCG, we herein deny Constellation's request for rehearing on that claim. Any claim that CCG has against CMS Energy is a separate issue and, in any case, as noted in the Initial Decision, is not appropriately brought under Paragraph 45.

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[280] *Id.* P 455.

[281] Constellation Request for Rehearing at 21 (citing Constellation Brief on Exceptions to the Initial Decision at 35-38).

[282] *Id.* at 21-22.

J. Green Mountain's Status vis-à-vis SECA Charges

1. Order on Initial Decision

184. In the Order on Initial Decision, the Commission disagreed with the Initial Decision's finding that "[s]ince 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."[283] Thus, the Commission reversed the Initial Decision's conclusions that Green Mountain is a "customer" under the Midwest ISO tariff and that Midwest ISO properly filed unexecuted service agreements on Green Mountain's behalf pursuant to Schedule 22. Consequently, the Commission also reversed the Initial Decision's conclusion that Midwest ISO properly assessed Green Mountain SECA charges as a customer within a designated subzone under Schedule 22.[284]

185. The Commission also reversed the Initial Decision's finding that Green Mountain should pay SECA charges based on its contractual arrangements with BP Energy. Instead, the Commission found that the Initial Decision ignored the lack of a contractual relationship between the Midwest ISO and Green Mountain. Rather, the Commission found that BP Energy was the network transmission customer with the contractual relationship with Midwest ISO. In addition, the Commission found that any claim that the Commission should impose SECA charges on Green Mountain because Green Mountain provided retail electric service in Ohio is unpersuasive. The Commission stated that, although Green Mountain qualifies as a load-serving entity because it sold power at retail to customers in Northeast Ohio, the transmission service in this instance was taken by BP Energy instead of Green Mountain. Therefore, the Commission found that, since BP Energy is the entity that took transmission service on behalf of Green Mountain, BP Energy is responsible for paying SECA charges.[285]

2. Requests for Rehearing

186. Green Mountain asserts that the Commission correctly reversed the Initial Decision's findings that Green Mountain was liable for SECA charges. Green Mountain states that the Commission correctly found that: (1) Green Mountain is not a "customer"

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[283] Order on Initial Decision, 131 FERC ¶ 61,173 at P 421 (citing Initial Decision, 116 FERC ¶ 63,030 at P 563).

[284] *Id*. P 423.

[285] *Id*. P 423-25.

under the Midwest ISO tariff; (2) Midwest ISO improperly assessed Green Mountain SECA charges as a customer under Schedule 22 of the Midwest ISO tariff; (3) Midwest ISO did not properly file unexecuted service agreements on Green Mountain's behalf; and (4) Green Mountain is not liable for the nearly $32 million, without interest, of SECA charges for which it was invoiced by Midwest ISO.

187. BP Energy argues that the Commission erred in assessing SECA charges against BP Energy because the Order on Initial Decision ignored what BP Energy characterizes as the plain language of Schedule 22. BP Energy states that under Schedule 22 the term "customer" means transmission customers as well as other entities in a zone that may not be transmission customers but which bear responsibility for some SECA charges. BP Energy contends that Green Mountain is an entity that should bear some responsibility for some SECA charges because Green Mountain is recognized as a SECA subzone in Attachment B of Schedule 22.

188. BP Energy adds that the fact that BP Energy took network service from Midwest ISO that may benefit Green Mountain is irrelevant to Green Mountain's SECA responsibility, since Schedule 22 is the filed rate. BP Energy maintains that shifting Green Mountain's subzonal SECA liability based on BP Energy's status as a network customer ignores the plain meaning of Schedule 22. Thus, BP Energy argues that, since Green Mountain is a customer under Schedule 22 and Attachment B to Schedule 22 specifically identifies Green Mountain as a subzone, BP Energy should not be assessed SECA charges as a network customer to the extent that it served Green Mountain.

189. In addition, BP Energy asserts that Schedule 22 gives Midwest ISO the authority to file unexecuted transmission service agreements whether the entities request their submission or not, and Midwest ISO filed these unexecuted agreements in Docket No. ER05-1423-000. BP Energy claims that, in accepting the unexecuted agreements, the Commission assigned SECA liability to Green Mountain and rejected Green Mountain's position that it was not a customer for purposes of Schedule 22 because it did not take transmission service.

190. BP Energy also contends that the Commission erred in assessing SECA charges against BP Energy even though load-serving entities benefit from the implementation of the SECA. BP Energy adds that the Order on Initial Decision noted that Green Mountain is a load-serving entity under the Midwest ISO tariff, and BP Energy adds that BP Energy is not a load-serving entity under the Midwest ISO tariff.

191. Furthermore, BP Energy claims that the Commission erred in failing to consider that the Energy Services Agreement between Green Mountain and BP Energy provides that all transmission and energy market costs are Green Mountain's responsibility. Specifically, BP Energy asserts that, under section 9.3 of the Energy Services Agreement, Green Mountain is liable for any SECA charges that are related to any deliveries under the Energy Services Agreement.

192. BP Energy also argues that the Commission erred in finding that BP Energy is liable for SECA charges because BP Energy was deprived of due process. BP Energy states that it was not provided with a meaningful opportunity to defend itself, and there were no claims to shift Green Mountain's SECA liability to BP Energy pending as of the procedural deadline for such claims. BP Energy asserts, therefore, that it did not receive adequate notice that BP Energy's liability for SECA charges was at issue in the hearing.[286]

193. BP Energy contends that the Commission erred in finding that BP Energy is responsible for SECA charges because the Commission violated the prohibition against retroactive ratemaking. BP Energy states that the Order on Initial Decision was issued on May 21, 2010. Thus, BP Energy asserts that, by assessing SECA charges against BP Energy for the period from December 2004 through March 2006, the Order on Initial Decision retroactively established a rate for BP Energy for service undertaken during prior years.[287]

194. BP Energy also claims that, even if the Commission determines that the SECA rates were fixed prior to the Order on Initial Decision, the SECA rates could become effective no earlier than February 10, 2005 for Rate Period 1 and June 16, 2005 for Rate Period 2. BP Energy contends that allowing the SECA rates to become effective December 1, 2004 is contrary to section 206(a) of the FPA because the Commission did not issue any order in this proceeding on December 1, 2004 nor did it accept any compliance filings on that date.

195. AEP, Dayton, and Exelon assert that the Order on Initial Decision failed to clarify that the PJM transmission owners should receive interest on the unpaid SECA amounts originally assigned by Midwest ISO to Green Mountain. AEP, Dayton, and Exelon state that one of the reasons that the PJM transmission owners have yet to be fully compensated for their lost revenues is that Midwest ISO failed to collect SECA charges from BP Energy initially.

196. AEP, Dayton, and Exelon explain that Midwest ISO originally determined that BP Energy was liable for the SECA obligations attributable to Green Mountain's retail load. In this regard, they state that Midwest ISO charged and collected about $11.5 million in SECA charges from BP Energy, but, on July 7, 2005, BP Energy informed Green Mountain that BP Energy disputed those charges and requested that Midwest ISO instead

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[286] BP Energy Request for Rehearing at 35-37.

[287] *Id.* at 22 (citing *Elec. District No. 1 v. FERC*, 774 F.2d 490 (D.C. Cir. 1985); *City of Anaheim v. FERC*, 558 F.3d 570 (D.C. Cir. 1989)).

bill Green Mountain. AEP, Dayton, and Exelon further explain that, on August 24, 2005, Midwest ISO changed its position and informed Green Mountain that it was responsible for all of the SECA charges allocated to the Green Mountain subzone, and Midwest ISO returned the $11.5 million to BP Energy. They add that, on August 25, 2005, Midwest ISO sent Green Mountain a letter confirming that Green Mountain was responsible for 100 percent of the SECA charges associated with the Green Mountain subzone.[288]

197. Therefore, AEP, Dayton, and Exelon request that the Commission clarify that: (1) SECA invoices to BP Energy and the "entity newly taking transmission service"[289] must include interest assessed from the date that the SECA charges were originally assessed to Green Mountain; or (2) Green Mountain, which refused to pay the SECA bills, should pay the interest; or (3) Midwest ISO, which failed to recover the SECA charges owed by Green Mountain, should pay the interest.

3. **Commission Determination**

198. As discussed below, we will deny rehearing, including BP Energy's request for rehearing of the Commission's decision that BP Energy, and not Green Mountain, is responsible for SECA charges.

199. In the Order on Initial Decision we found that BP Energy is the entity properly responsible for paying the SECA charges here, and not Green Mountain. Our finding relied on the fact that SECA, as originally proposed and as adopted by the Commission, is a surcharge to each RTO's license plate zonal rates. As such the SECA charge should be assessed to transmission customers taking transmission service under the RTO tariff that pay the license plate zonal rates. In the context before us, we reasoned that, since BP Energy is the entity that took transmission service, it is BP Energy that is properly

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[288] AEP, Dayton, and Exelon state that, on May 7, 2010, Midwest ISO issued a dunning letter stating that Green Mountain owed $41,676,268.42 in SECA charges (the $31,599,161.46 originally assessed plus $10,077,106.96, representing the interest on the unpaid amount). AEP, Dayton, and Exelon Request for Rehearing at 12.

[289] AEP, Dayton, and Exelon note that the Order on Initial Decision established that the Green Mountain subzone SECA obligation should be adjusted to reflect that Green Mountain served no load in Midwest ISO between January 2006 and March 2006. They add that the Order on Initial Decision held that the "entity newly taking transmission service" to serve this load during the remainder of the transition period should pay the generally applicable zonal SECA charge under Schedule 22. *Id.* at 13 (citing Order on Initial Decision, 131 FERC ¶ 61,173 at P 328).

responsible for paying the SECA charges.[290] In reaching our conclusion, we acknowledged that, on March 13, 2001, Green Mountain had entered into a firm all-requirements retail electric supply agreement with members of the Northeast Ohio Public Energy Council (NOPEC), and as a result, Green Mountain entered into contracts to obtain power for its Ohio load in Midwest ISO. But Green Mountain did not take transmission service from Midwest ISO. Rather, BP Energy is the entity that arranged for and took the transmission service from Midwest ISO.[291]

200. It would be unreasonable to find that Green Mountain is a Midwest ISO customer under Schedule 22 since its agreement with BP Energy specified the latter would take the service at issue. Green Mountain was never a transmission customer of Midwest ISO. Instead, it was BP Energy that took the transmission service under the Midwest ISO tariff, and as such was a customer under Schedule 22 and thus it is BP Energy that should be assessed SECA charges.

201. Under their contractual arrangement, if Green Mountain failed to pay BP Energy under their separate Energy Services Agreement, BP Energy was still obligated to pay Midwest ISO for network transmission service.[292]

202. Therefore, under the facts before us, we concluded, and we reaffirm here that we properly concluded, that BP Energy is responsible for the SECA charges here.

a. <u>Schedule 22</u>

203. We find that the Commission has already addressed, and rejected the same argument that BP Energy now makes on rehearing--in the Order on Initial Decision, where it reversed the Initial Decision's conclusions that Green Mountain is a customer under the Midwest ISO tariff and where it likewise reversed the Initial Decision's conclusion that Midwest ISO properly assessed Green Mountain SECA charges as a customer within a designated subzone under Schedule 22.[293]

204. In doing so, the Commission disagreed with the Initial Decision's finding that, even though Green Mountain did not directly contract with Midwest ISO, Green

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[290] Order on Initial Decision, 131 FERC at ¶ 61,173 at P 424.

[291] *Id*. P 404.

[292] *Id.* P 422.

[293] Order on Initial Decision, 131 FERC ¶ 61,173 at P 423. We also address the issue earlier in this order, where it was raised in a different context.

Mountain was ultimately responsible for transmission charges, since the procurement of network transmission service was for the benefit of Green Mountain and was its financial responsibility.[294] Instead the Commission stated that BP Energy and Green Mountain had negotiated a business arrangement in which the rights and responsibilities of the parties were established by contract. Under its contractual arrangement, Green Mountain had no obligation to purchase or to pay for network transmission service from Midwest ISO. The Commission found that, rather, BP Energy and Green Mountain had negotiated their own, separate business arrangement. Thus, under its contractual arrangement, if Green Mountain failed to pay BP Energy under their separate Energy Services Agreement, BP Energy was still obligated to pay Midwest ISO for network transmission service.[295] Accordingly, we continue to find that BP Energy is responsible for the SECA charges here.[296]

205. We also disagree with BP Energy's contention that the fact that it was the entity that took network transmission service from Midwest ISO and that service was taken to benefit Green Mountain, is irrelevant to Green Mountain's SECA responsibility. Rather, BP Energy was the transmission customer and thus is responsible for the SECA charges. Moreover, contrary to BP Energy's assertion, we find that the fact that it took network transmission service from Midwest ISO is pivotal to our conclusion that BP Energy is responsible for SECA charges based on the agreement between BP Energy and Green Mountain. In the Order on Initial Decision, the Commission stated that the SECA as originally proposed and adopted by the Commission is a surcharge to each RTO's license plate zonal rates,[297] and as such it properly should be assessed to transmission customers taking transmission service under the RTO tariff that pay the license plate zonal rates. Therefore, since BP Energy is the entity that took transmission service on behalf of Green Mountain through December 2005, BP Energy is responsible for paying SECA charges.[298] In contrast, Midwest ISO admits that Green Mountain was not a transmission customer of the Midwest ISO.[299]

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[294] *Id*. P 421 (citing Initial Decision, 116 FERC ¶ 63,030 at P 563).

[295] *Id*. P 423-24.

[296] *Id*. P 426.

[297] *Id*. P 424 (citing July 2003 Order, 104 FERC ¶ 61,105 at P 44; November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 17).

[298] *Id*. P 426.

[299] Initial Decision, 116 FERC ¶ 63,030 at P 465.

206. Moreover, the fact that BP Energy took transmission service for the benefit of Green Mountain is not a relevant concern. In fact, virtually every customer taking transmission service from Midwest ISO (or, indeed, any RTO) is taking that service to deliver electric energy to some third party, but that does not necessarily make the third party liable to Midwest ISO (or to any other RTO). While the third party may be liable to the transmission customer, any liability between the third party and the transmission customer is a matter solely between the two of them.

b. **Unexecuted Service Agreements**

207. We disagree with BP Energy's assertion that, in accepting the unexecuted agreements filed by Midwest ISO for the purpose of invoicing Green Mountain SECA charges, the Commission rejected Green Mountain's position that it was not a customer under Schedule 22 because it did not take transmission service. In the order accepting for filing four unexecuted transmission service agreements and one unexecuted market participant agreement in Docket No. ER05-1423-000, the Commission expressly deferred ruling on Green Mountain's arguments that it was not a customer under Schedule 22.[300] Specifically, the Commission noted Green Mountain's argument that the Commission should not assess SECA charges on Green Mountain because it does not purchase transmission service from Midwest ISO.[301] In response, the Commission stated that "the appropriate proceedings in which to address Green Mountain's arguments is not this instant proceeding but rather the pending rehearing proceedings . . . and in the ongoing hearings on the SECA compliance filings, in which Green Mountain is an active participant." Therefore, the Commission stated that it was not addressing in Docket No. ER05-1423-000 whether Midwest ISO could lawfully assess SECA charges against Green Mountain under Schedule 22. The Commission added that, consistent with the pending rehearing proceeding and its previous orders upholding the levy of SECA charges pending the final outcome of the ongoing hearings, the Commission would accept the unexecuted service agreements filed by Midwest ISO, subject to the eventual outcome of the proceedings in Docket No. ER05-6-001, *et al.*[302] Consistent with the Commission's prior order in Docket No. ER05-1423-000, explaining where Green Mountain's arguments would be addressed, the Order on Initial Decision ultimately did address Green Mountain's arguments. Consistent with the Order on Initial Decision, we continue to find that Green Mountain was not a customer for purposes of Schedule 22

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[300] *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,114, at P 12-13 (2005) (October 2005 Order).

[301] *Id.* P 16.

[302] *Id.* P 17.

because it did not take transmission service, and was thus not responsible for SECA charges. Instead, BP Energy, based on the agreement between BP Energy and Green Mountain, was the entity liable for SECA charges.[303]

c. Load-Serving Entity

208. We find BP Energy's claim that the Commission should impose SECA charges on Green Mountain because it provided retail electric service in Ohio to be without merit. As the Commission stated in the Order on Initial Decision, the mere fact that Green Mountain made retail sales[304] cannot justify imposing SECA charge, since Green Mountain did not itself take transmission service. Indeed, if the existence of retail sales were an appropriate basis to assess SECA charges, then they should be assessed to all entities selling at retail and not merely Green Mountain. But the presence of retail sales, where the seller is not a transmission customer of Midwest ISO or PJM, is not, in fact, an appropriate basis to assess SECA charges given, as described above, the nature of the SECA.

209. BP Energy also misinterprets the Commission's discussion of the benefits resulting from the elimination of rate pancaking. The Commission stated that it is not possible to precisely identify all of the benefits associated with the elimination of rate pancaking and how those benefits will be distributed. It added that allocating lost revenues to load in proportion to the through-and-out service used to serve that load under pancaked rates, as the SECA does, is a reasonable approach because it allocates costs in proportion to the benefits that can reasonably be identified.[305] But that logic does not translate into a need to assess SECA charges to all those providing retail electric service when they are not themselves a transmission customer. While Green Mountain is a load-serving entity, it is not a transmission customer of either Midwest ISO or PJM; although Green Mountain sold power at retail to customers in Northeast Ohio, it was BP

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[303] Order on Initial Decision, 131 FERC ¶ 61,173 at P 426. Because BP Energy, and not Green Mountain, is responsible for SECA charges, we find that Green Mountain's request for rehearing filed in Docket No. ER05-1423-001 (October 2005 Order, 113 FERC ¶ 61,114) is moot and will therefore be dismissed. The various subsequent motions and answers, filed after Green Mountain's request for rehearing, in Docket No. ER05-1423-001 are also moot.

[304] Under the Northeast Ohio Public Energy Council Agreement, entered into on March 31, 2001, Green Mountain agreed to serve retail customers in Northeast Ohio. Order on Initial Decision, 131 FERC ¶ 61,173 at P 424.

[305] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 85.

Energy, and not Green Mountain, that took network transmission service from Midwest ISO. Thus, we reiterate that Green Mountain is not subject to SECA charges.[306]

d. Energy Services Agreement

210. We find that BP Energy's claims concerning section 9.3 of the Energy Services Agreement are outside the scope of this proceeding. BP Energy is the Midwest ISO's transmission customer under Midwest ISO's tariff not Green Mountain, and enforcement of the Energy Services Agreement between Green Mountain and BP Energy is a separate matter outside the scope of this proceeding. Insofar as the Energy Services Agreement between Green Mountain and BP Energy makes Green Mountain liable to BP Energy for transmission and energy costs, any such dispute is between Green Mountain and BP Energy. It does not make Green Mountain liable here to Midwest ISO, and it does not make Green Mountain liable here for SECA charges. It is BP Energy that took transmission service from Midwest ISO and therefore it is BP Energy that is liable for SECA charges. Whether and to what extent Green Mountain is, in turn, liable under the Energy Services Agreement to BP Energy for the SECA charges that are assessed to BP Energy is a separate matter not relevant to this proceeding.

e. Due Process

211. We disagree with BP Energy's argument that it was deprived of due process. The Commission has previously addressed, in the May 2010 Rehearing Order, the same argument that BP Energy raises here. In that order, the Commission explained that the concept of applying a transitional lost revenue recovery mechanism in the transition away from pancaked rates for transactions crossing the Midwest ISO-PJM border had been discussed by the parties and the Commission many times during the course of these proceedings – since June 2002 at least, with further discussion in pleadings and orders dating to 2004 and 2005.[307] At hearing, in fact, BP Energy, like other parties, had the opportunity to defend itself; Midwest ISO had shifted liability from BP Energy to Green Mountain, and Green Mountain and other parties argued vigorously during these proceedings that BP Energy and not Green Mountain should be responsible for SECA charges and BP Energy responded.[308] Thus the issue of who should be liable has been in

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[306] Order on Initial Decision, 131 FERC ¶ 61,173 at P 425.

[307] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 125.

[308] *E.g.*, Initial Decision, 116 FERC ¶ 63,030 at P 558, 566-67 Indeed, as the Presiding Judge noted, Green Mountain and BP Energy both briefed this very issue. *Id.* P 523-33, 556-58.

dispute for many years and BP Energy had the opportunity to, and did, participate. Therefore, we find that BP Energy was not deprived of due process.

f. Retroactive Ratemaking and Filed Rate Doctrine

212. We disagree with the claim that allocating SECA charges to BP Energy constitutes retroactive ratemaking. In the May 2010 Rehearing Order, the Commission fully addressed parties' arguments that the SECA constitutes retroactive ratemaking and violates the filed rate doctrine, which are the same arguments that BP Energy makes here. The Commission discussed at length, including discussing the cases BP Energy now cites, why the SECA did not constitute retroactive ratemaking or violate the filed rate doctrine.[309] We see no reason to repeat the Commission's extensive prior discussion here, but rather we deny rehearing for the same reasons.

213. Furthermore, we disagree with BP Energy that it was not given adequate notice that it might be assessed Green Mountain's share of the SECA. As we stated above, our prior order rejected arguments that parties had not been provided adequate notice that they might be subject to SECA charges. We reject them again here for the reasons provided above. We add that, in accepting Midwest ISO's unexecuted agreements in October 2005 (well before the hearing before the Presiding Judge had commenced (that occurred on May 1, 2006)) for the purpose of invoicing Green Mountain SECA charges in Docket No. ER05-1423-000, the Commission expressly deferred ruling on Green Mountain's arguments that it should not be assessed SECA charges. The Commission stated that it accepted the unexecuted service agreements filed by Midwest ISO, subject to the eventual outcome of the proceedings in Docket No. ER05-6-001, *et al*.[310] Therefore, we find that BP Energy could and should have reasonably expected that it could be assessed SECA charges, and thus had sufficient notice of that possibility.

g. Interest Payment

214. In the May 2010 Rehearing Order, the Commission rejected objections to paying interest on the SECA charges, noting that the payment of interest is necessary to ensure full compensation for the time value of not paying the principal earlier. The Commission added that there should be no harm resulting from the payment of interest, since those

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[309] May 2010 Rehearing Order, 131 FERC ¶ 61,174 at P 126-42.

[310] October 2005 Order., 113 FERC ¶ 61,114 at P 15-17. In fact, Green Mountain as early as September 2005 had made public its intent to argue in Docket No. ER05-6-001, *et al.*, that BP Energy rather than Green Mountain should be liable for SECA charges. *Id.* P 16; *see also id.* P 17.

paying interest have benefitted from retaining the principal, as they had the use of the principal for a longer period than if they had paid the principal earlier. Furthermore, the Commission stated that there has been no showing that there was an unreasonable delay in billing.[311] We see no reason to reverse those determinations here.

215. Therefore, consistent with the express language of the May 2010 Rehearing Order, since BP Energy is responsible for SECA charges, it is also equally responsible for interest payments. In addition, consistent with the Order on Initial Decision, the "entity newly taking transmission service" that is responsible for SECA charges between January 2006 and March 2006[312] is also equally responsible for interest payments. Thus, we expect that SECA invoices to BP Energy and the "entity newly taking transmission service" would include interest from the date that the SECA charges were originally assessed to Green Mountain.

The Commission orders:

(A) The requests for rehearing are hereby denied, as discussed in the body of this order.

(B) The request for rehearing in Docket No. ER05-1423-001 is hereby dismissed as moot.

(C) Docket Nos. ER05-6-043, EL04-135-045, EL02-111-063, and EL03-212-059 are hereby dismissed as moot.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[311] *Id*. P 144.

[312] Order on Initial Decision, 131 FERC ¶ 61,173 at P 328.