121 FERC ¶ 61,025
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Dynegy Midwest Generation, Inc. Docket No. EL05-72-002

OPINION NO. 498

ORDER ON INITIAL DECISION

(Issued October 12, 2007)

1. This case is before the Commission on exceptions to the Initial Decision issued by the Presiding Judge on September 12, 2006.[1] At issue is whether a previously accepted rate schedule filed by Dynegy Midwest Generation, Inc. (DMG) on November 30, 2004 (November 2004 Rate Schedule or Accepted Rate Schedule)[2] continues to be just and reasonable under section 206 of the Federal Power Act (FPA).[3] The Accepted Rate Schedule sets forth DMG's cost-based revenue requirement for provision of reactive supply and voltage control from generation sources service (reactive power service) in the control area of the Illinois Power Company (Illinois Power).[4] In the Dynegy

[1] *Dynegy Midwest Generation, Inc.*, 116 FERC ¶ 63,052 (2006) (Initial Decision).

[2] *Dynegy Midwest Generation, Inc.*, Docket No. ER05-270-000 (Jan. 25, 2005) (unpublished letter order) (Dynegy Letter Order), *reh'g denied*, 110 FERC ¶ 61,358 (2005) (Dynegy Investigation Order) (*see infra* note 6).

[3] 16 U.S.C. § 824d (2000).

[4] In its filings, Illinois Power calls itself "Illinois Power Company d/b/a Ameren IP." For clarity and consistency with prior orders, we will refer to it as Illinois Power.

Investigation Order, the Commission instituted an investigation under section 206 of the FPA[5] into the continued justness and reasonableness of the November 2004 Rate Schedule, and established a refund effective date of June 7, 2005, and hearing and settlement judge procedures. For the reasons discussed below, we will affirm in part and reverse in part the Initial Decision.

I. Background

A. History of Reactive Power Pricing

2. The modern history of reactive power pricing begins with Order No. 888.[6] In Order No. 888, the Commission decided that reactive power was one of six ancillary services transmission providers must include in their OATTs.[7] The Commission stated that there are two methods of supplying reactive power and controlling voltage: (1) installing facilities as part of the transmission system and (2) using generation facilities. The Commission concluded that the costs of the first method would be recovered as part of the cost of basic transmission service and thus would not be a

[5] 16 U.S.C. § 824e (2000).

[6] Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs., Regulations Preambles January 1991-June 1996 ¶ 31,036 at 31,705-06 and 31,716-17 (1996), Order No. 888-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 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).

[7] Order No. 888 at 31,705. The *pro forma* open access transmission tariff (OATT) includes six schedules that set forth the details pertaining to each ancillary service. The details concerning reactive power are included in Schedule 2 of the *pro forma* OATT. *Id.* at 31,960.

separate ancillary service.[8] The second method (using generation facilities) would be considered a separate ancillary service, and must be unbundled from basic transmission service.[9] The Commission stated that, in the absence of proof that the generation seller lacks market power in providing reactive power, rates for this ancillary service should be cost-based and established as price caps, from which transmission providers may offer a discount.[10]

3. The next stage in the development of modern reactive power pricing is Opinion No. 440.[11] In Opinion No. 440, the Commission approved a method for American Electric Power Service Corp. (AEP) to recover costs of reactive power (*AEP* methodology). The *AEP* methodology generally reflects the costs associated with four groups of plant investments including the generator-exciter,[12] generator step up transformers (GSU), accessory equipment and the remaining production plant investment. Since these groups of production power plant investment involve both reactive and real power, under the *AEP* methodology, an allocation factor is developed to sort the annual revenue requirements of components between real and reactive power production.

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[8]Supplying reactive power and voltage control by installing facilities as part of the transmission system is not at issue in this proceeding.

[9]We note that, in Order No. 890, the Commission modified Schedule 2 of the *pro forma* OATT to indicate that Reactive Supply and Voltage Control may be provided by generating units as well as other non-generation resources such as demand resources where appropriate. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 888 (2007).

[10]Order No. 888 at 31,720-21.

[11]*American Electric Power Service Corp.,* Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*).

[12]The cost of the generator-exciter is generally isolated from the turbine-generator-exciter costs based on a manufacturer's suggested percentage.

4. The allocator used to determine the amount of generator-exciter investment related to reactive power is based on the ratio of $MVAR^2$ to MVA^2 (reactive allocator) where MVAR is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of one. Because GSUs also facilitate the transmission of real and reactive power, GSUs are allocated using the same reactive allocator to determine the portion related to reactive power service. Accessory equipment, including such equipment as auxiliary generators, generator main connections, and station buses are allocated to reactive power production using the product of two allocators. The first allocator is the ratio of generator-exciter auxiliary load (MW) divided by total production plant auxiliary load (MW).[13] The second allocator used to determine the portion of accessory equipment that is reactive-related is the same reactive allocator used for generator-exciters and GSUs. The remaining production plant investment is calculated by subtracting the generator-exciter, GSU and accessory equipment from total production plant to avoid double counting. The remaining production plant investment is allocated to reactive power service using the allocator called the remaining power plant investment allocator (RPPIA) or balance of plant (BOP) allocator, which is the product of two ratios. The first ratio is Exciter MW/Generator MW. The second ratio is the maximum MVars/nameplate MVars.

5. Once the reactive related costs of the generator-exciter, GSUs, accessory equipment and remaining production power plant are identified, the sum of these, known as the total reactive power plant investment, is multiplied by a fixed charge rate excluding operation and maintenance (O&M) expense. For O&M expenses under the *AEP* methodology, a portion of expenses associated with Maintenance of Electric Plant accounts (Accounts 513, 531 and 544) and Maintenance of Miscellaneous Other Power Generation (Account 554) are assigned to the reactive power revenue requirement. The rest of non-fuel O&M expenses are allocated to the reactive power revenue requirement using the same BOP allocator as used for the remaining plant.

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[13] Initially, in lieu of this allocator, engineering judgment was used to separate out accessory equipment. See Exhibit No. S-4, at 12.

B. DMG's Proposed Rate Schedule

6. In its cover letter to the proposed November 2004 Rate Schedule, DMG[14] stated that it had utilized the *AEP* methodology[15] consistent with the Commission's recommendation in *WPS Westwood Generation, L.L.C.*[16] DMG further stated that the proposed November 2004 Rate Schedule had a fixed capability component designed to recover the portion of plant costs attributable to the reactive power capability of the

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[14] DMG explained that it is a wholly-owned, indirect subsidiary of Dynegy Inc. and an affiliate of Dynegy Power Marketing, Inc. DMG stated that in 1999 DMG's predecessor company bought from Illinois Power the eight electric generating plants whose provision of reactive power service is at issue in this proceeding. According to DMG, "[g]iven the proximity of DMG's units to Illinois Power's load, DMG is the main source of reactive power for Illinois Power." Each turbine-generator set at these facilities connects to the Illinois Power transmission grid through its own generator step-up transformer owned by DMG. November 2004 Rate Schedule filing at 3. In 2000, DMG was granted exempt wholesale generator status and, in 2004, authorization to sell ancillary services, including reactive supply and voltage control services, at market-based rates. *Dynegy Midwest Generation, Inc.*, 92 FERC ¶ 62,253 (2000). Also in 2000, DMG succeeded to the Commission's approval of its predecessor's long-term power purchase agreement that permits the sale of power at market-based rates to Illinois Power. *See Illinova Power Marketing, Inc.*, 88 FERC ¶ 61,189, at 61,648-49 (1999), and *Dynegy Midwest Generation, Inc.*, Docket No. ER00-1895 (May 4, 2000) (delegated letter order). In 2001, as revised in 2004, Illinois Power and DMG executed an Interconnection Agreement (Revised Interconnection Agreement) under which DMG provides reactive power service to Illinois Power, and compensation is determined by the Illinois Power tariff or, when applicable, the tariff of a regional transmission operator (RTO). *Illinois Power Co*., Docket No. ER01-1706-002 (November 21, 2001) (delegated letter order); *Illinois Power Co.*, Docket No. ER04-390-000 (March 4, 2004) (delegated letter order). Also in 2004, Dynegy sold its subsidiary, Illinois Power, to Ameren Corp. Illinois Power would continue to secure reactive power from DMG under the November 2004 Rate Schedule.

[15] *AEP*, 88 FERC ¶ 61,141.

[16] *WPS Westwood*, 101 FERC ¶ 61,290, at 62,167 (2002) (Commission recommended that generators seeking reactive power recovery and having actual costs data use the method employed in *AEP*).

generators,[17] and a heating losses component designed to recover the cost of real power caused by increased generator and transformer heating losses that result from the actual production of reactive power.[18] The annual revenue requirements for these components are $5,015,854 and $2,568,946, respectively, for a total $7,584,800 annual reactive power revenue requirement.[19]

7. DMG also asked that its proposed November 2004 Rate Schedule be made effective January 1, 2005, if the Commission had by then approved the Midwest Independent System Operator (Midwest ISO) Tariff provisions governing compensation to generators for providing reactive power. Otherwise, DMG asked that Illinois Power compensate it directly for the supplied reactive power pursuant to the November 2004 Rate Schedule.[20]

[17] To calculate the fixed capability component, DMG analyzed the costs associated with the reactive power portion of its investment in the generator/exciter system and the generator step-up transformer, the accessory electric equipment, and the balance of plant costs, using allocation factors to determine the portion of plant investment attributable to the reactive power service function.

[18] To calculate the heating losses component, DMG evaluated, at a constant level of real power production, the difference in generator currents with no reactive power production (i.e., unity power factor) versus generator currents with reactive power production.

[19] To determine an annual revenue requirement, the reactive power related plant investment was multiplied by an annual carrying cost, using a levelized annual carrying cost approach. DMG incorporated in its annual carrying cost a return on equity (ROE) and capital structure based on a group of companies whose risk indicators are average for the electric utility industry.

[20] According to DMG's November 2004 Rate Schedule filing at 4, absent implementation of the tariff on January 1, 2005, DMG would not be compensated for providing reactive power to Illinois Power (citing *Ameren Corp.*, 108 FERC ¶ 61,094 (2004)) accepting for filing a power purchase agreement for Dynegy Power Marketing, Inc. to provide Illinois Power all of its energy and ancillary services needs exclusive of reactive power.

8. In an October 1, 2004 order,[21] the Commission had directed Midwest ISO to revise its Schedule 2 to provide compensation for reactive power service from all generators, including independent power producers. Subsequently, the Commission conditionally accepted a compliance filing containing a revised Schedule 2, to be effective January 1, 2005.

9. On January 25, 2005, DMG's November 2004 Rate Schedule setting forth its reactive power revenue requirement was accepted by delegated order to be effective January 1, 2005.[22] Illinois Power filed a request for rehearing contending that DMG's rate schedule had not been shown to be just and reasonable, and may be unjust, unreasonable, or unduly discriminatory. Illinois Power questioned DMG's revenue requirement, which it claimed was almost three-and-one-half times higher than the revenue requirement calculated by Illinois Power for largely the same eight generating units when Illinois Power owned them in 1998.

10. The Commission denied Illinois Power's request for rehearing; however, the Commission instituted the instant section 206 proceeding and established a refund effective date of June 7, 2005, as well as hearing and settlement judge procedures.[23] A hearing commenced in May 2006 following unsuccessful settlement discussions.

II. Discussion

11. As discussed below, we affirm the following determinations by the Presiding Judge and find that: (1) DMG's O&M expenses, administrative and general (A&G) expenses, and rate of return are just and reasonable; (2) actual operating data, not available flowgate capacity (AFC) models, should have been used in calculating the numerator of the second ratio for determining the RPPIA or balance of plant (BOP) allocator; (3) DMG's reactive power revenue requirement need not be adjusted for plant

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[21] Midwest Indep. Transmission Sys. Operator, Inc., 109 FERC ¶ 61,005 (2004) (MISO I), order on reh'g, 110 FERC ¶ 61,267 (2005) (MISO II), order on compliance filing, 113 FERC ¶ 61,046 (2005) (MISO III), order on reh'g and compliance, 114 FERC ¶ 61,192 (2006) (MISO IV), order on reh'g and compliance, 116 FERC ¶ 61,283 (2006) (MISO V).

[22] Dynegy Letter Order.

[23] Dynegy Investigation Order, 110 FERC ¶ 61,358 at P 1.

use; and (4) the unopposed adjustments based on supplemental information are appropriate.[24]

12. However, as discussed further below, we reverse the Presiding Judge on the following issues finding that: (1) DMG's use of a plant-by-plant approach to calculate the numerator in the RPPIA/BOP allocator was not just and reasonable; (2) fixed costs associated with heating losses are already included in the *AEP* methodology and an additional recovery of such fixed costs is not appropriate; and (3) DMG's supplemental information should be accepted into the record as cost support. To the extent not discussed below, we affirm the Presiding Judge.

13. Based on these determinations, we find that DMG's November 2004 Rate Schedule is no longer just and reasonable. Therefore, we direct DMG to file a revised rate schedule consistent with the determinations made in this order. We also direct DMG to make any necessary refunds and file a refund report.

A. Percentage of Fixed Non-Fuel O&M Costs

14. In developing the fixed capability component of the reactive power service revenue requirement,[25] DMG allocated a portion of its investment in each of the facilities to reactive power service. DMG applied a carrying charge, reflecting such things as depreciation, return, income taxes, O&M expenses and A&G expenses, to the total investment allocated to reactive power service for each facility to develop the reactive power service revenue requirement.

15. DMG does not maintain its books according to the Uniform System of Accounts (USofA). Based on its own analysis, DMG determined that 90 percent of its 2004 non-fuel O&M costs were fixed and when this fixed O&M is included in DMG's carrying charge applied to reactive power-related investment, DMG develops an amount of fixed O&M costs to include in the fixed capability component of the revenue requirement. DMG's determination that 90 percent of its non-fuel O&M costs to be fixed is significantly more than the 47 percent used by the generating units' previous owner,

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[24] Specifically, there were several computational adjustments to which the parties agreed and the Presiding Judge affirmed; these are addressed below in the discussion on DMG's "new rate filing."

[25] The Fixed Capability Component of the reactive power revenue requirement recovers all the fixed costs of providing reactive power service.

Illinois Power, in its 1999 reactive power revenue requirement which was based on 1998 data from the USofA.

1. **Presiding Judge's Findings**

16. The Presiding Judge explained that DMG was not required to follow the USofA, and agreed with DMG that, given the passage of time, the change in ownership of the facilities, and changes in operation of the power generating facilities, it is not reasonable to assume that 1998 data (before the USofA waiver was granted)[26] is an adequate indicator of 2004 costs and allocations.[27] Therefore, the Presiding Judge concluded that the other parties had failed to demonstrate that DMG's allocation between fixed and variable non-fuel O&M costs based on 2004 data was unjust, unreasonable, or unduly discriminatory.[28]

2. **Exceptions**

17. Illinois Power proposes that the Commission require the use of the *AEP* methodology for O&M expenses. The *AEP* methodology, also called the "Reising approach," does not use an average O&M fixed charge rate applied to investment to develop the fixed capability component of the reactive power revenue requirement.[29] Instead, the *AEP* methodology uses the cost data in the USofA format and allocates a portion of various accounts to the fixed capability component of the reactive power revenue requirement. The *AEP* methodology also allocates the rest of non-fuel O&M to the fixed capability component of the reactive power revenue requirement using the same BOP allocator as used for remaining plant. Illinois Power states that it calculated the

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[26] In 1999, DMG (formerly Illinova Power Marketing, Inc.) was granted a waiver from 18 C.F.R. part 101; since that time, DMG has not maintained its books in accordance with the USofA. *See Illinova Power Mktg., Inc.*, Docket No. ER99-3208-000 (letter order) (Aug. 24, 1999).

[27] Initial Decision, 116 FERC ¶ 63,052 at P 101.

[28] *Id.* at P 102-03.

[29] The methodology approved by the Commission in *AEP* was proposed by an intervenor witness, Paul Reising. Exhibit No. AIP-1 at 14-15.

amount of fixed O&M using the *AEP* methodology based on 1998 data resulting in a reduction in O&M expenses of approximately $650,000.[30]

18. Illinois Power acknowledges that it would be difficult for DMG to use the *AEP* methodology because DMG does not maintain its books according to the USofA. Thus, as an alternative to the *AEP* methodology, Illinois Power states that, if DMG is allowed to use the carrying charge approach in its filed rate, DMG should be required to reduce the percentage of total non-fuel O&M from 90 percent to 47 percent. According to Illinois Power, the 90 percent allocation was unsupported and suspect in light of Illinois Power's classification in its 1999 revenue requirement of only 47 percent of its non-fuel O&M costs as fixed in its reactive power filing for essentially the same plants.[31] According to Illinois Power, the Presiding Judge "unjustifiably excuses DMG's lack of support . . . based upon DMG's waiver from the requirements of using the [USofA]."[32] Illinois Power claims that the waiver of the USofA was granted in connection with DMG's market-based rate authorization, not with regard to cost-based rate proposals. Illinois Power proposes that the Commission require DMG to adopt Illinois Power's 47 percent level based on 1998 data as the amount of non-fuel, fixed O&M expenses.

19. Trial Staff contends that DMG did not specifically assign reactive-related O&M costs as is done under the *AEP* methodology.[33] Trial Staff claims that the fact that DMG is not obligated to follow the USofA is irrelevant and does not permit DMG to disregard the requirements of the *AEP* methodology.[34]

20. Trial Staff claims that it adequately demonstrated that DMG's O&M costs are unjust and unreasonable. Trial Staff says that it did not ignore the 2004 cost data provided by DMG; in fact, it asserts Mr. Mills utilized that data in his calculations.[35] Trial Staff states that Mr. Mills looked to 1998 data, the latest data available formulated

[30]Exhibit No. AIP-1 at 5.

[31]Illinois Power Brief on Exceptions at 18-19 (noting that Illinois Power's classification was made using the USofA).

[32]*Id.* at 19.

[33]Trial Staff Brief on Exceptions at 11.

[34]Id.

[35]*Id.* at 10. Trial Staff used 47 percent for the O&M based on 1998 data.

in accordance with the USofA, solely to calculate that percentage of reactive-related O&M costs, which Trial Staff applied to DMG's proposed O&M expenses. According to Trial Staff, an adjustment to the 2004 data was needed because DMG failed to follow the *AEP* methodology.

3. Opposing Exceptions

21. DMG states that the Presiding Judge was correct in finding that Illinois Power and Trial Staff failed to demonstrate that DMG's O&M costs were unjust and unreasonable.[36] In addition, DMG asserts that Illinois Power and Trial Staff failed to demonstrate by substantial evidence that the rate they proposed is just, reasonable, and not unduly discriminatory. DMG contends that its treatment of O&M costs is reasonable; it followed Commission precedent in allocating O&M costs and used actual 2004 data. In contrast, it maintains, neither Trial Staff nor Illinois Power used actual 2004 data; instead, they inappropriately relied upon data from 1998.

22. DMG argues further that it followed the methodology used by other generators to develop the O&M and A&G components. DMG concludes that "[g]iven that the Commission has accepted reactive power tariffs of many other merchant generators who similarly are not required to follow the Commission's USofA, and thus could not have used the Reising approach, it does not appear that the Commission views this as a requirement of the *AEP* Methodology."[37] According to DMG, neither Illinois Power nor Trial Staff refute the fact that the Commission has accepted an alternative approach in determining fixed non-fuel O&M. Therefore, DMG argues, Trial Staff has not met its section 206 burden; Trial Staff's calculation is based on stale data that is not applicable to the current situation.[38]

4. Commission Determination

23. We affirm the Presiding Judge's determination, for the reasons stated in the Initial Decision, that Illinois Power and Trial Staff have not shown that DMG's O&M calculation using 2004 data is unjust and unreasonable. As the Presiding Judge explained, given the passage of time, the change in ownership, and changes in operations, it is not reasonable to assume that 1998 data is an adequate indicator of 2004 costs and

[36] DMG Brief Opposing Exceptions at 14-15.

[37] *Id.* at 16 (quoting from Exhibit No. DMG-2.0).

[38] *Id.* at 18 (quoting Initial Decision, 116 FERC ¶ 63,052 at P 101).

allocations. Moreover, while Illinois Power argues that the Presiding Judge unjustifiably excused DMG's lack of support based on DMG's waiver from the requirements of using the USofA,[39] Illinois Power has provided no evidence to indicate that DMG's O&M calculation using 2004 data (but not following the USofA) is unjust and unreasonable.

B. Appropriate Percentage of A&G Costs

1. Presiding Judge's Findings

24. All the parties agreed that the appropriate percentage of A&G costs attributable to reactive power service is the same percentage as that used for the non-fuel O&M costs discussed above. The Presiding Judge found that the contesting parties failed to demonstrate that DMG's O&M costs were unjust and unreasonable. Consequently, the Presiding Judge also found that the parties had failed to demonstrate that DMG's A&G costs were unjust and unreasonable.[40]

2. Exceptions

25. Trial Staff claims that the Presiding Judge erred in finding that it failed to demonstrate that DMG's A&G costs were unjust and unreasonable. Trial Staff notes that the parties agreed that the percentage used for non-fuel O&M costs should also apply to A&G costs. Therefore, for the same reasons cited in its exceptions on O&M costs, it asserts that the Commission should find that the Presiding Judge erred in finding that Trial Staff failed to establish that DMG's A&G expenses were unjust and unreasonable.[41]

3. Opposing Exceptions

26. DMG argues that, given Trial Staff's failure to demonstrate that DMG's O&M costs are not just and reasonable, the Presiding Judge's decision regarding DMG's A&G costs as well as its O&M costs should be affirmed.[42]

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[39] DMG received a waiver from complying with the USofA in connection with its market-based rate authorization.

[40] Initial Decision, 116 FERC ¶ 63,052 at P 107.

[41] Trial Staff Brief on Exceptions at 13.

[42] DMG Brief Opposing Exceptions at 20.

4. Commission Determination

27. All of the parties agree that the same allocation used for O&M expenses should be used for A&G expenses. For the reasons set forth above in our discussion concerning the allocation of O&M costs, and the parties' general agreement to use identical allocators for O&M and A&G, we affirm the Initial Decision and find, based on the record in this proceeding, that the parties have failed to demonstrate that DMG's A&G costs are unjust and unreasonable.

C. Appropriate Method for Determining the Remaining Power Plant Investment Allocator (RPPIA) or Balance of Plant (BOP) Allocator

28. As explained previously, the reactive power revenue requirement is calculated according to the *AEP* methodology which generally includes costs associated with such things as the generator-exciter, generator step up transformers, accessory equipment and the remaining production plant investment. Since these involve both reactive and real power, the *AEP* methodology allocates each of these to reactive power production. The allocators used for generator-exciter, generator step up transformers and accessory equipment are not contested in this proceeding. The allocator (i.e., RPPIA or BOP allocator) used to determine the reactive power production portion of the remaining production plant investment is the product of two ratios. The first ratio, which is also not contested in this proceeding, is Exciter MW/Generator MW. The second ratio is the maximum MVars/nameplate MVars. The parties' disagreement is with the numerator of the second ratio (i.e., maximum MVars).

1. Presiding Judge's Findings

29. The Presiding Judge ruled on two contested issues concerning the numerator of the second ratio. The first issue was whether to use AFC models or actual operating data to determine the maximum MVars produced by a unit. DMG's filed rate initially appeared not to have a second ratio, but DMG in its cost support explained that it used AFC models which resulted in a second ratio of one. The Presiding Judge found that AFC models are not appropriate because they are scrubbed to mask generator outages and, thus, are inappropriate for evaluating the maximum level of reactive power that a unit is expected to produce.[43] Trial Staff and Illinois Power had proposed using actual operating data and the Presiding Judge found that actual historical operating data used by Trial Staff was equitable and was appropriate for use to determine the maximum amount of

[43] Initial Decision, 116 FERC ¶ 63,052 at P 52.

reactive power to calculate the numerator in the second ratio used to calculate the BOP allocator/RPPIA.[44]

30. The second issue involving the numerator of the second ratio was whether to determine the maximum MVars for each plant individually (i.e., the plant-by-plant approach) or to determine the MVars for all the plants on a simultaneous basis. The Presiding Judge found that Illinois Power failed to meet its burden of demonstrating that DMG's use of the plant-by-plant approach in determining its revenue requirement is unjust or unreasonable. The Presiding Judge found that the Commission has approved such an approach in the past. Although the Presiding Judge noted that use of the plant-by-plant approach results in a different outcome, the Presiding Judge found that no party had shown that it was unreasonable.[45]

2. Exceptions

31. Illinois Power claims that the Presiding Judge erred in accepting DMG's use of a plant-by-plant approach in determining the BOP allocator/RPPIA of the fixed capability component. According to Illinois Power, DMG did not apply the *AEP* methodology correctly in determining the second of two ratios used to calculate the BOP allocator/RPPIA, but instead relied on what others in the industry were filing, which Illinois Power argues is not a substitute for the just and reasonable standard.[46]

32. According to Illinois Power, in *AEP*, a simultaneous (or coincident) control area output on the system peak hour was used to derive the second ratio of the BOP allocator/RPPIA, which "'adjusts for diversity among the [r]eactive [p]ower outputs of the individual generators by relating the maximum simultaneous reactive mega VAR output to the total system mega VAR capability.'"[47] Therefore, Illinois Power argues

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[44] *Id.* at P 84-85.

[45] *Id.* at P 86.

[46] Illinois Power Brief on Exceptions at 16-17 (quoting from Exhibit No. DMG-1.0 (corrected) at 12). At the hearing, Mr. Mason stated: "From the very start, we filed our revenue requirement on a plant-by-plant basis, because that's the way that we had seen all other IPPs file their revenue requirement; whereas AEP back when they did it was an integrated utility. So they filed as a fleet-wide system basis." Tr. 218:17-25 (Mason).

[47] *Id.* at 17 (quoting Mr. Mason, who was quoting from Mr. Pasternack's direct testimony in Docket No. ER93-540).

that the second ratio in the BOP allocator/RPPIA calculation "should be based upon the output of all of the fossil plants in the control area at the time of maximum output of the control area, not the peak output of an individual plant."[48]

33. Illinois Power claims that DMG admits that the use of the maximum monthly outputs of each generator results in a much higher output than if DMG had used the coincident generating unit maximum as used in *AEP*. Illinois Power alleges that DMG "cherry-picked" individual maximum plant output values to calculate the second ratio, undermining the *AEP* methodology.

3. <u>Opposing Exceptions</u>

34. DMG alleges that Illinois Power, the only participant arguing that development of the second ratio on a plant-by-plant basis is unjust, unreasonable, or unduly discriminatory, fails to carry its burden to demonstrate this. DMG notes that the Commission has previously found that "[f]or the rate design proposal to be acceptable, it need be neither perfect nor even the most 'desirable;' it need only be reasonable."[49] Acknowledging that its plant-by-plant approach results in a different outcome than alternative approaches would yield, DMG alleges that Illinois Power has not demonstrated that DMG's approach is flawed. According to DMG, the issue is whether the *AEP* methodology is static or whether it has evolved; DMG claims that it has evolved over the years and that Illinois Power ignores the evolution.[50] According to DMG, without reviewing the Commission's order and other reactive power filings, "Illinois Power's witness could not credibly opine as to whether DMG's approach was just and reasonable."[51]

35. In its brief opposing exceptions, Illinois Power argues that DMG's final RPPIA/BOP allocator value is not appropriate and the Presiding Judge's findings on the plant-by-plant approach should be reversed. DMG's filed rate did not include the second

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[48]*Id.* at 17-18.

[49]DMG Brief Opposing Exceptions at 13 (quoting *California Independent System Operator,* 106 FERC ¶ 63,026, at P 344-45 (2004)).

[50]*Id.* at 12-13.

[51]Id.

ratio of the allocator, although it "later attempted to explain away this critical error by indicating that it utilized a second ratio of 1.0 . . . ."[52]

36. In contrast to DMG's approach, Illinois Power explains that it used operational data in accordance with *AEP* to determine the maximum MVar output for the numerator of the second ratio, an approach approved in the Initial Decision. According to Illinois Power, the correct approach, "as utilized in *AEP* and set forth by Illinois Power, is to use the simultaneous output of all the plants in the control area at the time of maximum output of the control area to develop the second ratio . . . ."[53] Illinois Power contends that the Presiding Judge's approval of DMG's plant specific approach should be rejected.[54]

4. **Commission Determination**

37. First, we note that no party filed exceptions to the Presiding Judge's finding that use of the AFC models is unjust and unreasonable in determining the maximum amount of reactive power provided by the DMG generators when developing the numerator of the second ratio of the RPPIA.[55] As noted by the Presiding Judge, AFC models are not a reasonable representation of the steady state reactive power needs for the system.[56] Since appropriate load flow data was not presented in the record,[57] we affirm the Presiding

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[52]Illinois Power Brief Opposing Exceptions at 22.

[53]*Id.* at 23.

[54]Id.

[55]In *AEP*, a load flow model was used in combination with actual historical data. Exhibit AIP-48. *See also* Supplemental Rebuttal Testimony of Bernard M. Pasternack, Docket No. ER93-540-000, Exhibit A-90 (1995), at 5-8.

[56]Initial Decision, 116 FERC ¶ 63,052 at P 83, and Exhibit No. S-18.

[57]Trial Staff states that the 2004 FERC Form No. 715 part 2 summer case may be the most appropriate source for determining the numerator of the second ratio; however, Trial Staff's review indicates that it may not be representative of DMG's units. The output report of the 2004 FERC Form No. 715 Part 2 summer case reveals that many of DMG's units were not operating; therefore, DMG would not get credit for those units. Consequently, Trial Staff recommended using historical operating data to ensure all of DMG's units were reflected. *See* Exhibit No. S-16, pages 3-4.

Judge's decision that the use of actual historical operational data of the DMG facilities to determine the maximum amount of reactive power provided by the DMG generators when developing the numerator of the second ratio is reasonable.[58] We note that the Presiding Judge in *Bluegrass* made the same determination, and that the Commission affirmed the *Bluegrass* Initial Decision on this issue.[59] We recognize that independent power producers such as DMG have limited access to suitable load flow data for determining generator reactive power production.[60] However, they do have access to historical operating data for their own generators, and this is a reasonable substitute for the load flow data used in *AEP*.

38. As to whether the historical numerators of the second ratio should be on a plant-by-plant basis or on a simultaneous basis, we find that Illinois Power has shown that the plant-by-plant approach used by DMG is not just and reasonable, and therefore, we reverse the Presiding Judge on this issue. Unlike other independent power producer (IPP) proceedings, upon which DMG relies to support the plant-by-plant approach, DMG operates a fleet of generating units.[61] Since the *AEP* methodology was initially developed for an entity that operated a fleet of generation, we find that the just and reasonable approach to use in this proceeding is the approach that most closely follows the *AEP* methodology. As acknowledged by Trial Staff, the plant-by-plant approach deviates from the *AEP* methodology;[62] whereas the simultaneous approach advocated by Illinois Power is equivalent to the approach taken in *AEP* for a fleet of generating units.

39. We find the simultaneous approach just and reasonable for a fleet of generating units because not all generators provide maximum reactive power output at the time of system peak. In other words, different generators provide their maximum reactive power output at different times (i.e., diversity among reactive power outputs of generators) so that some generators always have reactive power available to the transmission operator as

[58] Initial Decision, 116 FERC ¶ 63,052 at P 85.

[59] Bluegrass Generation Company, L.L.C, 118 FERC ¶ 61,214, at P 91 (2007) (Bluegrass).

[60] *See* Transcript at 217: 24- 218: 3. *See also Bluegrass,* 118 FERC ¶ 61,214 at n.239 (quoting Bluegrass' Brief on Exceptions at 7 in Docket No. ER05-522).

[61] As previously stated, DMG is the main source of reactive power for Illinois Power.

[62] *See* Exhibit No. S-16, page 5, lines 16-20 and page 6, lines 1-2.

reactive reserves to respond to changes in system voltage due to unexpected transmission or generation outages. Thus, the simultaneous method most closely represents the way that a fleet of generators would provide reactive power by recognizing the diversity of the generators. A plant-by-plant approach does not reflect this diversity in reactive power output because it allows the fleet operator to selectively choose which times to model each generator, resulting in higher rates. The simultaneous method precludes fleet operators from cherry-picking the best days for each generator in order to inflate rates.

D. Appropriate Rate of Return, Return on Equity, Cost of Debt, and Capital Structure

1. Presiding Judge's Findings

40. The Presiding Judge found that the record supported DMG's filed rate of return of 9.47 percent, as set forth in DMG's filed rate and reflecting a return on equity (ROE) of 11.20 percent which the Presiding Judge found to be in a zone of reasonableness.[63] According to DMG, this rate of return incorporated an average capital structure and a ROE derived from a discounted cash flow (DCF) analysis based on a five company proxy group whose risk factors are average for the electric energy industry.[64] Thus, rather than base its rate of return on DMG's capital costs, DMG used a proxy of an "average electric energy company."

41. The Presiding Judge found that Trial Staff failed to meet its burden with respect to DMG's filed rate of return.[65] With respect to ROE, Trial Staff had performed a DCF analysis for DMG utilizing Illinois Power as a proxy[66] in order to demonstrate that DMG's filed rate of return is unjust and unreasonable; however, the Presiding Judge found fault with Trial Staff's analysis. According to the Presiding Judge, as a party seeking to use a proxy, Trial Staff had the burden to establish the need for a proxy and

[63] Initial Decision, 116 FERC ¶ 63,052 at P 124.

[64] *See* testimony of Raymond Cassidy, (Exhibit DMG-4), filed in Docket No. ER05-270-000, p. 5, lines 3-4.

[65] Initial Decision, 116 FERC ¶ 63,052 at P 127.

[66] Trial Staff's DCF analysis, utilizing Illinois Power as a proxy for DMG, resulted in a rate of return of 7.69 percent reflecting a ROE of 9.21 percent. Initial Decision at P 120, 123.

the suitability of the proxy being offered.[67] The Presiding Judge found Trial Staff's contention that Illinois Power is an appropriate proxy for DMG to be unpersuasive, recognizing that Commission precedent has recognized that non-utility generators with no guaranteed customers face greater risk than regulated utilities. The Presiding Judge found that Trial Staff's use of Illinois Power as a proxy for DMG failed to recognize the corporate credit rating for DMG, the specific risk associated with such rating, and investors' expectations with respect to DMG. The Presiding Judge also found that Trial Staff's DCF analysis of Illinois Power reflected investment grade companies, and that DMG and Dynegy Inc. were non-investment grade companies. For these reasons, the Presiding Judge rejected Trial Staff's DCF analysis, finding that Trial Staff had not demonstrated that DMG's ROE was unjust and unreasonable or that Trial Staff's DCF analysis was more appropriate than DMG's DCF analysis used to support the existing ROE.[68]

2. Exceptions

42. Trial Staff alleges that the Presiding Judge erred in finding that DMG's filed rate of return is just and reasonable. Among other things, Trial Staff alleges that DMG's proxy group is flawed, using criteria for inclusion in the proxy group that the Commission has rejected, and including entities that fail to meet DMG's own requirements for inclusion. Trial Staff contends that the Presiding Judge did not address any of the flaws in the construction of DMG's proxy group or reconcile them with Commission practice and precedent.[69]

43. Specifically, Trial Staff says that DMG's proxy group is inappropriate because it did not use "the appropriate source for finding growth rate projections for companies when compiling a proxy group for the DCF analysis."[70] In addition, Trial Staff states that "there is no Commission precedent requiring or even allowing relying on no less than two growth estimates."[71] In addition, DMG limited the proxy group to entities exhibiting a Standard and Poor's bond rating of BBB when Trial Staff argues that the corporate

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[67] *Id.* at P 128.

[68] *Id.* at P 130-31.

[69] Trial Staff Brief on Exceptions at 28.

[70] *Id.* at 28-29.

[71] *Id.* at 29.

credit rating should be used.[72] Trial Staff also alleges that DMG's analysis of its proxy group is flawed because it used the midpoint of returns instead of the median, as approved by the Commission.[73] According to Trial Staff, these numerous flaws in DMG's analysis demonstrate that DMG's cost of capital is unjust and unreasonable, and the Presiding Judge erred in finding that Trial Staff failed to meet its burden to demonstrate that.

44. Trial Staff agrees with DMG that the rate of return of an interconnected utility can serve as a proxy for an IPP's rate of return. However, rather than use the authorized ROE of Illinois Power to serve as a proxy for DMG's ROE, Trial Staff developed a new DCF analysis for Illinois Power utilizing four companies with risk profiles comparable to Illinois Power. Additionally, rather than use the authorized capital structure of Illinois Power to serve as a proxy for DMG's capital structure, Trial Staff used a hypothetical capital structure with a market-driven cost of debt reflecting what Trial Staff believes is DMG's actual risk profile.

45. Trial Staff also explains its rationale for developing a proxy group in this proceeding. According to Trial Staff, DMG does not issue its own non-guaranteed debt, does not possess its own bond rating, is not publicly traded and does not issue any dividend.[74] Thus, Trial Staff argues, it is not possible to calculate DMG's cost of capital.[75] Moreover, Trial Staff states that Dynegy Inc.'s cost of capital should not be

[72]Trial Staff states that a corporation can have more than one group of bonds and, as a result, have more than one bond rating. Trial Staff Brief on Exceptions at 29. Moreover, despite articulating its criterion, Trial Staff alleges that only one of the five companies in DMG's proxy group actually had a BBB bond rating. *Id.* at 29-30.

[73]Trial Staff Brief on Exceptions at 30 (citing *Midwest Independent Transmission System Operator, Inc.*, order on remand, 106 FERC ¶ 61,203, at P 10-11 (2004), *aff'd in part, reversed in part sub nom. PSC of KY v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005)). According to Trial Staff, median provides "the most refined measure of central tendency," while midpoint is "the average of the absolute high and absolute low returns of the companies comprising the proxy group," and is thus subject to distortion by an "outlier."

[74]Thus, Trial Staff contends that DMG does not have the necessary inputs to the Commission's discounted cash flow methodology

[75]Trial Staff Brief on Exceptions at 21-22.

used for DMG in this case.[76] Although the Commission will impute the capital structure of an applicant's parent company if the applicant's capital structure is not appropriate, Trial Staff maintains that it will not do so if the parent and subsidiary have significantly different risk profiles. In such cases, it asserts, the hypothetical capital structure for the subsidiary will be derived "by referring to the average capital structure for comparable independent firms, which also is the capital structure utilized to develop the return on common equity (a proxy group)."[77] Trial Staff asserts that use of a proxy is appropriate in this proceeding, given the differences between DMG and Dynegy Inc.'s risk profiles.

46. Trial Staff alleges that DMG faces far less risk than Dynegy Inc.[78] It argues that the cost of capital analysis should reflect DMG's relatively low risk, not the higher risks faced by Dynegy Inc.[79] Trial Staff also states that "[t]he rate of return applicable to a utility providing regulated service must reflect solely the risks of that portion of the utility's regulated business, and not any non-electric, non-regulated operations."[80] According to Trial Staff, imputing the risk profile of Dynegy Inc. to DMG unjustifiably

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[76]*Id.* at 23. According to Trial Staff, Mr. Wang testified that Dynegy Inc.'s equity ratio of 25 percent is far outside the range of other equity ratios approved by the Commission, and Mr. Cassidy testified that Dynegy Inc.'s common equity ratio is "'far below the norm for the electric industry.'" *Id.*

[77]*Id.* at 22 (citing, among other cases, *Holyoke Water Power Co.*, 37 FERC ¶ 61,223 (1986)).

[78]*Id.* at 17 (citing Staff witness Wang's testimony at hearing that it is normal for a FERC-regulated subsidiary to have a higher credit rating and to be less risky than an unregulated parent).

[79]According to Trial Staff, Dynegy Inc. "is a large, diversified company involved in a substantial level of both regulated and non-regulatory businesses." Trial Staff Brief on Exceptions at 16 (quoting *Bluefield Waterworks*, 262 U.S. 679, 692-93 (1923)). Trial Staff posits that unregulated endeavors are inherently riskier than those undertaken pursuant to a regulatory regime. Because Dynegy Inc. engages in unregulated activities, Trial Staff concludes that it "must be considered a 'speculative venture' with a higher risk profile than non-speculative activities." *Id.*

[80] Trial Staff Brief on Exceptions at 17 (citing *Connecticut Light & Power Co.*, Opinion No. 305-A, 45 FERC ¶ 61,370, 62,165 (1988)).

imputes non-regulated operations to DMG, which is solely in the business of electric generation.[81]

47. Trial Staff states that financial risk must be balanced against the business risk of a company's operations and, in this case, "DMG will receive its reactive power revenue requirement regardless of market conditions, demand, or even need." According to Trial Staff, the existence of customers like Illinois Power, that are obligated to purchase DMG's reactive power output, reduces DMG's risk.[82]

48. Trial Staff further alleges that it was error for the Presiding Judge to find that DMG's risk profile was higher than that of Illinois Power, and that Illinois Power was not a proper proxy for DMG.[83] Trial Staff defends its selection of Illinois Power, the interconnected transmission owner, as the basis for developing the proxy group for DMG, claiming that the Commission has found it appropriate to use the interconnected transmission owner as a proxy for developing cost of capital calculations.[84] According to Trial Staff, the same should hold true here.

3. <u>Opposing Exceptions</u>

49. DMG notes that, as a threshold matter, Trial Staff has the burden of demonstrating through substantial evidence that DMG's rate of return is unjust, unreasonable, or unduly discriminatory; a burden that the Presiding Judge found Trial Staff failed to meet. According to DMG, given that Trial Staff failed to meet its burden to show that DMG's rate of return was not just and reasonable, the evidence Trial Staff offered in support of its proposed rate of return is not relevant.[85]

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[81] *Id.* at 19-20 (quoting *Bluefield Waterworks*, 262 U.S. 679, 692-93, that a utility "'has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures'").

[82] *Id.* at 18 (citing *Connecticut Yankee Atomic Power Co.,* 20 FERC ¶ 61,373, at 61,766 (1982)).

[83] *Id.* at 21.

[84] Id. at 25 (citing FPL Energy Marcus Hook, L.P., 110 FERC ¶ 61,087 (2005); Tenaska Virginia Partners, 107 FERC ¶ 61,207 (2004) (Tenaska Virginia)).

[85] DMG Brief Opposing Exceptions at 21.

50. DMG states that, contrary to the position taken by Trial Staff, the Presiding Judge ruled that Trial Staff failed to meet its burden not because Trial Staff failed to impute Dynegy Inc.'s risk profile to DMG, but because Trail Staff failed to consider DMG's risk profile at all.[86]

51. DMG states that the Presiding Judge found that Illinois Power is an inappropriate proxy because the Commission has found that non-utility generators face greater risk than regulated utilities. DMG also states that the Presiding Judge noted that Trial Staff's witness on rate of return did not reference DMG's risk profile. Instead, DMG states, Trial Staff defended its use of Illinois Power as a proxy based on the fact that the Commission has previously allowed the use of the interconnected transmission provider as a proxy. Acknowledging this is the case, DMG notes that the Commission has only permitted the use of the interconnected utility as a proxy where the generator has not contested it, and in *Calpine Fox LLC*,[87] the generator was the one seeking to use the capital structure of the interconnected utility as a proxy. According to DMG, the Presiding Judge correctly found that cases cited by Trial Staff "'do not demonstrate that the Commission approves the use of the interconnected utility's rate of return without any further risk analysis in a contested proceeding.'"[88] DMG also notes that in *Detroit Edison* the Commission found that "'it is not appropriate simply to apply the [return on equity] from the Midwest ISO Order for use in Detroit Edison's ancillary service rates without further investigation.'"[89] DMG claims that the Presiding Judge was correct in determining that Trial Staff failed to support its use of Illinois Power as a proxy.

52. DMG further asserts that, although Trial Staff claims that Illinois Power is an appropriate proxy for DMG, Trial Staff does not use Illinois Power's authorized rate of return to calculate the rate of return for DMG. Rather, Trial Staff constructed a proxy group for Illinois Power and calculated a different rate of return. Trial Staff said that it did so because Illinois Power's return on equity "'from other cases may not reflect current market conditions.'"[90] DMG alleges that Trial Staff's failure to justify its

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

[87] 113 FERC ¶ 61,047 (2005).

[88] DMG Brief Opposing Exceptions at 22-23 (quoting Initial Decision, 116 FERC ¶ 63,052 at P 129).

[89] *Id. at* 23 (quoting *Detroit Edison*, 105 FERC ¶ 61,124, at 62,358-59 (2003)).

[90] *Id.* at 24 (quoting Exhibit No. S-1).

selection of Illinois Power in the first place makes its use of a proxy group with a risk profile similar to Illinois Power's similarly faulty. Therefore, it asserts, the Presiding Judge correctly determined that Trial Staff did not meet its burden.[91]

53. DMG states that it did not base its filed rate on the use of Dynegy Inc. as a proxy. Moreover, even if the Presiding Judge had "conflated" the risk profiles of Dynegy Inc. and DMG as alleged by Trial Staff, it would not matter because Trial Staff failed to provide evidence that its proposed proxy group is an appropriate proxy for DMG. According to DMG, "[t]he Presiding Judge's finding that Staff failed to meet its burden can and does rest sufficiently upon the determination that Staff failed to demonstrate that its proposed proxy group is appropriate proxies [sic] for DMG."[92]

4. Commission Determination

54. As discussed below, we affirm the Presiding Judge's conclusion that DMG's existing rate of return is just and reasonable and find that Trial Staff has not shown that DMG's filed rate of return is unjust and unreasonable. In a recent decision, the Commission affirmed a judge's determination that Bluegrass' proposed capital structure and proposed overall return, based on the *authorized* rate of return of the interconnected utility (LG&E, as a transmission owner in the Midwest ISO), were just and reasonable.[93] The Commission found that the use of the interconnected utility as a proxy for a merchant generator was just and reasonable and explained its general policy of allowing merchant generators to use the interconnected utility's *authorized* rate of return as a proxy.[94] In supporting its use of such a proxy, the Commission explained that an interconnected utility's return is a conservative estimate of a merchant generator's return because the merchant generator faces more risk.[95]

55. Thus, had DMG chosen to do so, it could have sought a rate of return and return on common equity, which in this case would have been Illinois Power's *authorized* rate

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[91] *Id.* at 24.

[92] *Id.* at 26.

[93] *Bluegrass*, 118 FERC ¶ 61,214 at P 86. Bluegrass is an affiliate of DMG and was allowed to use the generic Midwest ISO ROE of 12.38 percent.

[94] Id.

[95] Id.

of return of 11.52 percent (reflecting the Midwest ISO's return on common equity of 12.38 percent).[96] Instead, DMG used a lower rate of return and return on common equity (9.47 percent rate of return reflecting a return on common equity of 11.10 percent), based on a DCF analysis reflecting a five company proxy group. Consequently, despite Trial Staff's concerns regarding the specifics of the calculation of DMG's rate of return and return on common equity, Trial Staff has not shown that the end result, i.e., DMG's existing rate of return and return on common equity, is unjust and unreasonable. Accordingly, we affirm the conclusion in the Initial Decision that DMG's existing rate of return and return on common equity are just and reasonable and have not been shown to be unjust and unreasonable.

E. Whether to Allow a Heating Losses Component as Part of the Revenue Requirement

1. Presiding Judge's Findings

56. DMG's reactive power service revenue requirement of $7,584,800 includes a $5,015,854 annual fixed capability component and a $2,568,946 heating losses component.[97] The Presiding Judge found that although the Commission has accepted for filing other revenue requirements that include the heating losses requirement in reactive power service filings, such acceptance for filing does not reflect analysis or approval on the merits, and thus does not constitute Commission precedent and is not binding on the Commission.[98] Therefore, the Presiding Judge found that this issue was presented on the merits for the first time. After a review of the record and Commission directives in various cases, the Presiding Judge concluded that the Commission has signaled a clear intent to permit IPPs to recover all costs associated with providing reactive power service as an ancillary service.[99] The Presiding Judge found that DMG does incur costs in the form of heating losses related to reactive power service provided as an ancillary service, and accordingly heating losses should be considered as part of DMG's reactive power service revenue requirement.[100]

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[96] *See* Illinois Power Brief Opposing Exceptions at 12.

[97] Initial Decision, 116 FERC ¶ 63,052 at P 165.

[98] *Id.* at P 142.

[99] *Id.* at P 144.

[100] *Id.* The Presiding Judge also made determinations with respect to heating losses

(continued)

2. Exceptions

57. Trial Staff, Illinois Power, and the Midwest ISO Transmission Owners take exception to the Presiding Judge's finding that inclusion of a heating losses component is appropriate under Commission precedent; they claim that there is no heating losses precedent, as this is the first litigated case on the merits of that issue.[101] In addition, Trial Staff states that the Presiding Judge correctly noted that the Commission directed the Midwest ISO to include language in its Schedule 2 that provides for IPPs to file cost-based revenue requirements prior to being compensated.[102] Trial Staff also states that the Presiding Judge correctly found that the cited MISO orders[103] address cost-based reactive power revenue requirements and compensation, but do not reference heating losses.[104] According to Trial Staff, "the MISO cases, which concern Schedule 21 and Schedule 2, contain no precedent or guidance, or indeed any references, concerning heating losses[;]"

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calculations, finding that they should be based on rated capability, not maximum capability, and that they should be cost-based. The Presiding Judge also found that a heating losses component need not be adjusted to account for losses from plant. In light of our determination below not to permit a separate heating losses component, we are not addressing the Presiding Judge's findings with regard to how to appropriately calculate the heating losses component.

[101] Trial Staff Brief on Exceptions at 34-36; Illinois Power Brief on Exceptions at 12-13; Midwest ISO Transmission Owners Brief on Exceptions at 7-8 (*AEP* established a methodology for determining fixed capability costs, and permits an annual fixed recovery intended to compensate for the capability of producing reactive power if and when called upon by the transmission provider). The parties also took exception to some of the Presiding Judge's determinations regarding the appropriate calculation of a heating losses component; those arguments are not detailed here in light of our determination not to permit a separate additional heating losses component as part of the revenue requirement.

[102] Trial Staff Brief on Exceptions at 35-36.

[103] *MISO I*, 109 FERC ¶ 61,005; *MISO II*, 110 FERC ¶ 61,267; *MISO III*, 113 FERC ¶ 61,046; *MISO IV*, 114 FERC ¶ 61,192; *MISO V*, 116 FERC ¶ 61,283.

[104] Trial Staff Brief on Exception at 37-39. *See also* Midwest ISO Transmission Owners at 11 (orders relating to Schedule 2 address the need for comparability between transmission owners' generating units and IPPs with regard to recovery of fixed cost-based reactive power revenue requirements; they do not address heating losses).

therefore, it was error for the Presiding Judge "to conclude that heating losses should automatically be recovered."[105]

58. According to Trial Staff and the Midwest ISO Transmission Owners, the Presiding Judge acknowledges that the cases containing a heating losses component that did not proceed to hearing cannot be considered established Commission precedent,[106] but then finds that the cases signal the Commission's "clear intent" to permit recovery of heating losses. In addition, they point out, in each case in which the Commission permitted such recovery, the heating losses revenue requirement was a smaller percentage of its total revenue requirement than DMG has claimed. They explain that DMG has claimed heating losses that amount to more than one third of its annual revenue requirement for reactive power.[107]

59. Trial Staff states that the Presiding Judge was correct in observing that the Commission's acceptance for filing of a revenue requirement including a heating losses component does not constitute Commission precedent because it does not reflect an approval on the merits of the filing and is not binding on the Commission. Even if it were precedential, Trial Staff asserts, it does not support recovery of heating losses on a capability basis.[108] Trial Staff states that DMG and the Presiding Judge agree that heating losses were not raised as an issue in *AEP*.[109] Therefore, Trial Staff alleges that the heating losses component is presented on the merits for the first time in this case.

60. Trial Staff states that the Initial Decision should be reversed because previous cases indicate that the Commission has concerns about heating losses calculations. According to Trial Staff, in *Duke Energy Vermillion*, one of the issues that the Commission set for hearing was whether recovery for heating losses due to reactive

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[105]*Id.* at 39.

[106]*Id.* at 35-36; Midwest ISO Transmission Owners Brief on Exceptions at 4-5. In some of the referenced cases, the Commission accepted and suspended the proposed rates, subject to refund and established hearing and settlement judge procedures; many of these cases later settled as part of "black box" settlements that did not differentiate costs allowed. *See* Midwest ISO Transmission Owners Brief on Exceptions at 11-12.

[107]Trial Staff Brief on Exceptions at 42.

[108]*Id.* at 43.

[109]*Id.* at 35.

power production is justified.[110] Similarly, in *Virginia Electric and Power Co.*,[111] the Commission set for hearing the issue of whether Virginia Power had overstated the amount and value of heating losses, specifically stating that "we have a question whether Virginia Power's calculation of heating losses based on the use of maximum possible generation significantly overstates its actual heating losses."[112] Given the record, Trial Staff alleges that the Presiding Judge should have found that the heating losses component was too large, and was not accurately measured and fully supported.[113]

61. Like Trial Staff, Illinois Power alleges that the Presiding Judge misinterpreted *AEP* with regard to heating losses, although she did acknowledge that: (1) the *AEP* methodology was applicable; (2) filings accepted by the Commission are not precedent; and (3) *AEP* did not address heating losses.[114] According to Illinois Power, those findings should have led the Presiding Judge to deny the heating losses component completely. Instead, the Presiding Judge used *AEP* to find that heating losses are a fixed cost incurred when providing reactive power. Illinois Power states that the Presiding Judge failed to consider that heating losses are not fixed investment costs; they are variable costs that are incurred only when the generator runs. Illinois Power alleges that "there is no investment or cost incurred for heating losses when the unit is standing by to provide [r]eactive [p]ower."[115]

3. Opposing Exceptions

62. DMG states that the Presiding Judge appropriately found that IPPs like DMG should be permitted to recover all costs, including heating losses, associated with reactive power service. DMG reiterates the burdens that Illinois Power, Trial Staff, and Midwest ISO Transmission Owners bear when challenging a rate under section 206(b). According to DMG, those entities challenging its rate, which was previously accepted by the

[110] *Id.* at 44 (citing *Duke Energy Vermillion*, 109 FERC ¶ 61,370, at P 7 (2004)).

[111] 114 FERC ¶ 61,318 (2006) (*Virginia Power*).

[112] Trial Staff Brief on Exceptions at 44-45 (citing *Virginia Power*, 114 FERC ¶ 61,318 at P 27).

[113] *Id.* at 45.

[114] Illinois Power Brief on Exceptions at 12.

[115] *Id.* at 13.

Commission, must provide substantial evidence that inclusion of the heating losses component and the associated calculation method is unjust, unreasonable, or unduly discriminatory in order to have the rate changed.

63. DMG concedes that the heating losses component was not raised in *AEP*, but states that subsequent Commission precedent on reactive power service revenue requirements recognizes inclusion of a heating losses component and establishes the basis for IPPs to include it in their reactive power service revenue requirement.[116] DMG challenges Trial Staff's contention that an order issued by the Commission is not precedent if it is not the product of a litigated proceeding, noting that numerous cases cited in Trial Staff's own brief were acted upon without a hearing.[117] Similarly, DMG alleges that the Midwest ISO Transmission Owners have neglected to address cases where the Commission addressed the heating losses component. DMG notes that the Midwest ISO Transmission Owners apparently do not consider Commission orders that discuss the inclusion of a heating losses component and accept those reactive power service revenue requirements for filing, to serve as precedent.[118] DMG claims that there are numerous cases discussing the inclusion of a heating losses component and which support DMG's calculation of its heating losses component.[119]

64. DMG states that in *Tennessee* the Commission "left the door open to delegation orders having precedential value." [120] DMG also interprets *Tennessee* to support the idea that when the Commission substantively considers an issue (even in a delegated order), it

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[116]DMG Brief Opposing Exceptions at 28.

[117]*Id.* at 29.

[118]*Id.* at 30 (also claiming that Midwest ISO Transmission Owners, like Trial Staff, are inconsistent with respect to whether cases may be relied upon as precedent where there has not been an evidentiary hearing).

[119]*Id.* (citing *Virginia Power*, 114 FERC ¶ 61,318; *Duke Energy Fayette, LLC*, 104 FERC ¶ 61,090 (2003) (*Duke Energy Fayette)*; *Conectiv Bethlehem, LLC*, 106 FERC ¶ 61,272 (2004) (*Conectiv*)).

[120]*Id.* at 31 (quoting *Tennessee Gas Pipeline Co. (Tennessee)*, 111 FERC ¶ 61,094 (2005), where the Commission stated with respect to a particular delegated order that "'its precedential value beyond that proceeding is limited because it was a delegation order and the Commission did not have the opportunity to review on rehearing . . . .'")

establishes precedent.[121] DMG further contends that the Commission has substantively addressed the heating losses component of reactive power revenue requirement in non-delegated orders, and that these decisions are precedent.

65. Additionally, DMG notes that delegated orders issued after the orders in which the Commission has substantively addressed the heating losses component have followed those Commission orders.[122] According to DMG, there have been delegated letter orders; orders acknowledging inclusion of a heating losses component while not setting the rates for hearing (Category I Acceptance Orders);[123] orders specifically addressing inclusion and calculation of a heating losses component (Category II Acceptance Orders);[124] and even an order in *Orion*[125] rejecting comments opposing inclusion of a heating losses component. DMG reasons that if inclusion of a heating losses component was not reasonable, the Commission would have taken issue with it in either *Duke Energy Fayette* or *Conectiv*, both of which involved the use of LMP in a heating losses calculation. In addition, it argues that although *Virginia Power* was set for hearing, heating losses were not an issue of concern; the issues of concern were whether it was appropriate to use maximum possible generation to calculate heating losses and whether use of forecasted LMP values was appropriate.[126] DMG claims that its use of rated power factor and LMP are consistent with the filings addressed in *Duke Energy Fayette* and *Conectiv*.

66. DMG refutes other parties' "flawed" attempts to challenge the level of its heating losses component. DMG states that its witness Roethemeyer explained at the hearing why its heating losses component is higher relative to the total annual revenue requirement than that of other companies. Of the two elements that make up the annual revenue requirements, DMG states, the net book value of a plant will drive down the

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[121] Id.

[122] *Id.* at 31-32.

[123] DMG cites *Tenaska Virginia*; 107 FERC ¶ 61,207; *Safe Harbor Water Power Corp.;* 102 FERC ¶ 61,272 (2003); *CED Rock Springs*, 110 FERC ¶ 61,083 (2005); and *Monongahela Power Co.*, 113 FERC ¶ 61,172 (2005).

[124] DMG cites *Duke Energy Fayette*, 104 FERC ¶ 61,190; *Conectiv*, 106 FERC ¶ 61,272; and *Virginia Power*, 114 FERC ¶ 61,318.

[125] *Orion Power MidWest, L.P.*, 110 FERC ¶ 61,246 (2005) (*Orion*).

[126] DMG Brief Opposing Exceptions at 34.

fixed capability component and operating hours will determine the heating losses component. Therefore, as a facility ages, the fixed capability component will fall, and the heating losses component will become a greater percentage of the total revenue requirement. In addition, according to DMG, "a baseload unit with higher operating hours will have higher losses than a peaker."[127] Therefore, DMG argues, comparison to new generation is "of no empirical value."[128]

67. DMG alleges that Illinois Power witness Gudeman essentially acknowledged that DMG followed Commission precedent in recognizing a heating losses component. DMG states that in *Duke Energy Fayette* a witness described how to calculate generator heating losses attributable to reactive power: "evaluat[e], at a constant level of [r]eal [p]ower production, the difference between (a) generator currents with no [r]eactive [p]ower production (i.e. operation at a unity power factor) and (b) generator currents when producing [r]eactive [p]ower at the generator's rated power factor limit."[129] This difference "is multiplied by the rated design electrical resistance values of the applicable DMG Facility's generator . . . .''[130] Generator step up transformer losses are calculated in a similar manner, "analyzed at a constant level of real power production, with and without reactive power production."[131] DMG states that the same process was described again in *Conectiv*, and urges the Commission to find that the parties challenging DMG's calculation of heating losses using rated reactive power capability, operation hours and LMP pricing have not met their burden.[132]

4. <u>Commission Determination</u>

68. We disagree with the Presiding Judge that an additional heating losses component to DMG's reactive power service revenue requirement is reasonable. We agree that generators should be compensated for the fixed costs of producing reactive power as an ancillary service and find that recovery of the fixed costs related to heating losses is

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[127] *Id.* at 48.

[128] Id.

[129] *Id.* at 49 (quoting Exhibit No. AIP-2).

[130] Id.

[131] Id.

[132] *Id.* at 50.

already included in the fixed capability component calculated under the *AEP* methodology. Because DMG has not supported the inclusion of any additional costs (i.e., variable costs) associated with heating losses that may not be recovered already pursuant to the *AEP* methodology, we find that it should not include a separate, additional component in its revenue requirement for heating losses.

69. As the *AEP* methodology is a fairly complex, multi-part calculation, it is important for the Commission to assess proposals for new additional reactive power charges to determine whether the charges are already reflected in the *AEP* methodology. DMG states in its initial brief that its heating losses component is not a part of the original *AEP* methodology.[133] Trial Staff makes an even stronger statement, stating that the *AEP* methodology does not address heating losses at all.[134] However, a review of the record in the proceeding in which the *AEP* methodology was adopted shows that heating losses were in fact included in the *AEP* methodology as a rationale for the remaining production plant investment of the *AEP* methodology.[135] Since the excitation system of a generator consumes energy (i.e., generates losses) when the generator produces reactive power, a generator must use a portion of its production capability to compensate for these losses. Thus, under the *AEP* methodology, generators are awarded compensation for a portion of their remaining production plant investment. Therefore, the remaining production plant investment portion of a rate calculated according to the *AEP* methodology recovers costs associated with heating losses. We also note that under the *AEP* methodology, generators are allowed to recover a portion of their fixed O&M costs as part of the carrying charge applied to the four groups of plant investment to calculate the revenue requirement. Therefore, despite any claims to the contrary, fixed O&M costs incurred as a result of heating losses also would have been previously included in the calculation.

70. We agree with the Presiding Judge's interpretation that the *AEP* methodology is meant to recover all fixed costs due to reactive power; however, allowing recovery of a separate heating losses component that includes fixed costs associated with heating losses would amount to double counting of fixed costs for heating losses as such costs are already included in the fixed capability component under the *AEP* methodology.

[133] DMG Initial Brief at 25-26.

[134] Trial Staff Initial Brief at 46.

[135] American Electric Power Services Corp., 80 FERC ¶ 63,006, at 74-75 (1997).

71. While the *AEP* methodology is limited to fixed cost recovery, if an applicant could demonstrate that it incurs variable costs associated with heating losses, we would consider such recovery. However, the record in this case does not demonstrate the amount of variable costs that DMG has incurred.[136] DMG has not provided the actual amount of heating loss costs incurred based on the MW-hours of actual reactive power production, but rather has provided only a hypothetical calculation assuming maximum reactive power production for all operating hours.[137] Also, we affirm the Presiding Judge that DMG incurs no opportunity costs due to heating losses for the reasons stated in the Initial Decision.[138] Consequently, the nature and amount of any heating losses costs above and beyond what already is provided for in the *AEP* methodology have not been demonstrated.

72. Moreover, none of the cases cited support inclusion of a separate heating losses component in addition to the recovery of heating losses allowed under the *AEP* methodology. Contrary to the arguments of DMG, we find that delegated letter orders do not constitute binding precedent.[139] In addition, section 35.4 of the Commission's Rule and Regulations, 18 C.F.R. § 35.4 (2007), specifies that "[t]he fact that the Commission permits a rate schedule or any part thereof . . . to become effective shall not constitute approval by the Commission of such a rate schedule . . . ." Likewise, the Commission has rejected claims that issues had been decided previously where the issue had not been affirmatively resolved by the Commission.[140] Therefore, we reject DMG's argument that

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[136]We also note that DMG considers 90 percent of its O&M costs as fixed O&M. Thus, any variable O&M costs attributable to heating losses for reactive power would be minimal.

[137]Initial Decision, 116 FERC ¶ 63,052 at P 49-51.

[138]*Id.* at P 53-55.

[139]*See Midwest Generation, LLC*, 95 FERC ¶ 61,231 (2001) ("actions taken by its staff pursuant to delegated authority 'do not constitute precedent binding the Commission in future cases . . . .'" (quoting *Phoenix Hydro Corp.*, 26 FERC ¶ 61,389, at 61,870 (1984), *aff'd, Phoenix Hydro Corp. v. FERC*, 775 F.2d 1187, 1191 (D.C. Cir. 1985))).

[140]*See id.* at n.17 ("In *Northeast Utilities Service Co.*, 74 FERC ¶ 61,065 (1996), the Commission discounted a claim that it had resolved an issue in earlier cases, where that issue 'was not affirmatively decided by the Commission'" (citing *United States v. Shabani*, 513 U.S. 10, 16 (1994); *Illinois Board of Elections v. Socialist Workers Party*,

(continued)

Commission precedent permits inclusion of a separate heating losses component as part of an IPP's reactive power service revenue requirement.

73. For the reasons discussed above, we reverse the Presiding Judge's finding concerning heating losses and find that a separate recovery of the fixed costs due to heating losses in addition to the fixed costs associated with heating losses recovered in the fixed capability component under the *AEP* methodology is unjust and unreasonable. Therefore, we require DMG to remove such costs from its revenue requirement to ensure that it is charging a just and reasonable rate.

F. Whether to Allow an Adjustment to Reflect Reactive Power Use by the Units

1. Presiding Judge's Findings

74. The Presiding Judge rejected Illinois Power's argument that DMG's revenue requirement should be adjusted to reflect DMG's own use of reactive power. The Presiding Judge found this to be another version of Illinois Power's argument that load should only pay for reactive power used, not costs associated with the capability to produce reactive power.[141] The Presiding Judge found that the *AEP* methodology should be followed absent "clear direction from the Commission that it no longer considers this methodology controlling." The Presiding Judge reiterated that application of the *AEP* methodology results in a fixed revenue requirement and capacity payments based on the capability to produce reactive power, and recovers all fixed costs, regardless of whether any service is actually provided, concluding that actual use adjustments are not appropriate.[142]

2. Exceptions

75. According to Illinois Power, the record shows that DMG currently uses over 50 percent of the reactive power it produces, yet it receives compensation for all the reactive power it produces, even though much of it never reaches the transmission system. Illinois Power alleges that, in effect, transmission system customers are subsidizing DMG's cost of producing real power. Illinois Power directs the Commission to look to

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440 U.S. 173, 183 (1979); and *Webster v. Fall*, 266 U.S. 507, 511 (1925))).

[141] Initial Decision, 116 FERC ¶ 63,052 at P 183.

[142] *Id.* at P 184-85.

the *AEP* methodology and cost-of-service ratemaking principles to determine that including a mechanism to account for DMG's own use of reactive power is just and reasonable.[143]

76. Illinois Power argues that the Presiding Judge's finding was in error because the *AEP* methodology divides costs among three groups of users of reactive power, namely network service customer load within the control area, entities using the transmission system by way of point-to-point transmission service requests, and the generation owner whose transmission assets use significant reactive power; therefore, DMG should be assessed costs in accordance with *AEP*.[144] Illinois Power claims that the three user groups benefit from the reactive power in this case as well, and that none should burden the other with its costs. According to Illinois Power, in this case the Midwest ISO Tariff collects the revenue requirement from groups one and two; therefore, the remaining task is to assign costs to the generation owner, DMG.[145]

77. Illinois Power asserts that the Presiding Judge appears to have confused the allocation of costs to the revenue requirement based upon fixed cost capability with assignment of costs to users.[146] According to Illinois Power, all of the parties agree that in deriving the reactive power revenue requirement, the cost of the generation investment allocated to reactive power is allocated based on the capability of the plant. However,

[143] Illinois Power Brief on Exceptions at 23-24.

[144] *Id.* at 21. Illinois Power states that DMG witness Mason admitted that the *AEP* methodology accounts for distribution among the three user groups. Illinois Power posits that if each of the three user groups used the same amount of reactive power, each group should be assigned one-third of the total cost of service; however, Illinois Power submits that users do not equally use the reactive power. In *AEP*, the network service customers (group one) and the generation users (group three) were part of the vertically-integrated AEP system and "did not need to be differentiated, as they were already bearing the costs of generation plant used to provide [r]eactive [p]ower costs to AEP." So, Illinois Power asserts, the only allocation involved the group two point-to-point transmission users; therefore, AEP used a cost per Kilowatt of transmission service based upon actual usage to charge group two for their share of the total reactive power revenue requirement. *Id.* at 22.

[145] *Id.* at 22-23.

[146] *Id.* at 23 (quoting Initial Decision, 116 FERC ¶ 63,052 at P 185).

Illinois Power maintains, *AEP* does not provide that capability is the basis for assigning the costs among users. According to Illinois Power, contrary to the findings of the Presiding Judge, actual usage is the appropriate basis for recovering the costs and the Initial Decision should have included a way to acknowledge DMG's use of reactive power.[147]

3. Opposing Exceptions

78. DMG argues that Illinois Power has not met its burden to show DMG's rate, which follows *AEP*, and Midwest ISO Schedules 2 and [21][148] is unjust or unreasonable.[149] According to DMG, Illinois Power's position is founded on two ideas: (1) that the *AEP* methodology provides for derivation of the reactive power service revenue requirement; and (2) that costs were allocated between network load users and generation users on the one hand and point-to-point transmission users on the other.[150] DMG notes that Illinois Power stated that network load users and the generation users were each part of the vertically integrated AEP system, and therefore did not need to be differentiated because they were already bearing the costs of generation plants used to provide reactive power costs to AEP.[151] According to DMG, Illinois Power's statement acknowledges that there was no allocation to the generation facilities themselves; the allocation was to transmission customers and bundled retail load. DMG states that "[n]owhere does Illinois Power provide any evidence that AEP absorbed the cost of reactive supply to retail customers, yet that is what Illinois Power is asking the Commission to believe."[152]

79. DMG argues that the Commission has previously addressed the generator step-up transformer issue that Illinois Power has raised. Specifically, in Opinion No. 440, it

[147] Id.

[148] Although DMG repeatedly cites to Schedule 20, we assume they meant Schedule 21, and we will refer to Schedule 21.

[149] DMG Brief Opposing Exceptions at 50.

[150] *Id.* (citing Illinois Power Brief on Exceptions at 22-23).

[151] *Id.* at 51 (quoting Illinois Power Brief on Exceptions at 23 (emphasis added by DMG)).

[152] *Id.* at 51.

asserts, the Commission rejected Commission staff's concerns regarding plant use of MVARs stating:

> We are not persuaded . . . that the reactive capability of the generators should be reduced by the [VARs] consumed by GSUs[153] and auxiliary loads before developing an allocation factor. We agree . . . that the allocation factor should be based on the capability of the generators to produce [VARs] and that this capability should be measured at the generator terminals. We find merit in AEP's assertion that a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system.[154]

80. In addition, DMG asserts that allocation of reactive power compensation has been addressed under Schedules 2 and 21 of the Midwest ISO Tariff. DMG notes Illinois Power's agreement that the Midwest ISO Tariff collects the revenue requirement from network users and point-to-point users, but does not assign cost responsibility to generators as a class.[155] DMG states that Illinois Power's opportunity to assess cost responsibility to generators was at the time Midwest ISO Schedules 2 and 21 were accepted.[156] Finally, DMG argues that the Commission should reject Illinois Power's proposal, which would discriminate against DMG compared to other generation within the Midwest ISO that is not subject to the adjustment.

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[153]Generator step-up transformers (GSUs).

[154]DMG Brief Opposing Exceptions at 51-51 (quoting Opinion No. 440, 88 FERC ¶ 61,141 at 41,457).

[155]According to DMG, absent revision of Schedule 2, it is the transmission customer that pays for reactive power service. DMG Brief Opposing Exceptions at 55.

[156]*Id.* at 52-54. ("To the extent Illinois Power disagreed with Schedule [21] and the omission of **all** generation using remote self-supply for [s]tation [p]ower, the forum for Illinois Power to challenge this was in the Schedule [21] proceedings . . . ." "To the extent Illinois Power determined that assignment of reactive power service costs to transmission customers alone under M[idwest] ISO Schedule 2 was not adequate, it should have raised the issue in the M[idwest] ISO Schedule 2 proceeding.")

4. Commission Determination

81. We affirm, for the reasons stated in the Initial Decision, the Presiding Judge's determination that Illinois Power did not demonstrate that DMG's reactive power revenue requirement should be adjusted for DMG's own use of reactive power, i.e., reactive power consumed by DMG's facilities.

82. Further, we reject Illinois Power's argument that generators instead of transmission customers should be assigned the cost responsibility for the extra amount of reactive power needed to get the required amount of reactive power to the transmission system. As we stated in Opinion No. 440, "we find merit in AEP's assertion that a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system" which is used by transmission customers.[157] This extra reactive power represents a cost to the generator of providing reactive power to the transmission system for the benefit of transmission customers. Without such extra reactive power, transmission customers would not be able to use the transmission system. Thus, the cost associated with this extra reactive power is properly collected from transmission customers.

G. DMG's "New Rate Filing"

1. Presiding Judge's Findings

83. The Presiding Judge noted that DMG, in its answering testimony, introduced supplemental information through what DMG called a "New Rate Filing"[158] to demonstrate that, if it had filed for a new rate at the time of its testimony, the revenue requirement would have been higher than it calculated in its initial rate filing. According to the Presiding Judge, "DMG has made clear that it is not proposing changes to its Filed Rate, but rather that it presents this alternative hypothetical revenue requirement in order to support its original filing."[159] However, noting that DMG could have submitted the supplemental information as part of a new and separate section 205 filing and elected not to do so, the Presiding Judge stated that the supplemental information was completely

[157] DMG Brief Opposing Exceptions at 51 (quoting Opinion No. 440, 88 FERC ¶ 61,141 at 41,457).

[158] We will refer to the "New Rate Filing" as "supplemental information."

[159] Initial Decision, 116 FERC ¶ 63,052 at P 26.

irrelevant to this proceeding and that she would not consider the supplemental information in analyzing the justness and reasonableness of the original rate filing.

Nevertheless, the judge adopted certain unopposed adjustments to DMG's as-filed rate based on the supplemental information contained in the "New Rate Filing."[160]

2. <u>Exceptions</u>

84. DMG alleges that the Presiding Judge erred in finding the supplemental information irrelevant to this proceeding. DMG explains that the supplemental information included adjustments, some of which corrected for overrecovery of costs and others for underrecovery of costs. According to DMG, the Presiding Judge acted inconsistently by evaluating and accepting the adjustments from the supplemental information that were agreed to by the parties (DMG, Illinois Power, and Trial Staff), while rejecting adjustments to which either Illinois Power or Trial Staff took exception. DMG states that the supplemental information should have been examined together with all of DMG's other evidence to ensure that all facts are considered in accordance with 18 C.F.R. § 385.505 and Commission precedent.[161] DMG also argues that the Presiding Judge's failure to consider all of the possible elements of the recalculation of the filed

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[160] Specifically, there were several computational adjustments to which the parties agreed and the Presiding Judge affirmed including a tax calculation correction, correction for depreciation, revision to plant net book value, correction to the reactive cost allocator for Vermilion, a pound per square inch gauge pressure revision, recognition of the Baldwin Unit 2 generator rewind, and an adjustment to the Hennepin Unit 2 reactive capability limit. Initial Decision, 116 FERC ¶ 63,052 at P 58-60. In addition, DMG conceded that an adjustment for accumulated deferred income taxes was appropriate, and the Presiding Judge found that it was appropriate to lower DMG's revenue requirement to account for accumulated deferred income taxes as recommended by Trial Staff. *Id.* at P 64.

[161] DMG Brief on Exceptions at 10. DMG cites *Southern Co. Services, Inc.*, 68 FERC ¶ 61,231 (1994) and *Cities of Greenwood and Seneca, South Carolina v. Duke Power Co.*, 77 FERC ¶ 63,017 (1996) in support of its claim that the Commission will consider evidence of updates or changes that have occurred between the time the rate is accepted and the initiation of a section 206 proceeding if the evidence relates to the continued justness and reasonableness of the filed rate.

rate, instead of her focus on the heating losses component alone, is inconsistent with Commission precedent.[162]

85. Noting that Illinois Power and Trial Staff have the burden of proving that DMG's filed rate is unjust and unreasonable, DMG claims that it submitted evidence in response to demonstrate that its rates are just and reasonable. DMG reiterates that it was not proposing to make changes to its filed rate, but that the supplemental information was submitted for comparison purposes only. DMG posits that the label "New Rate Filing" may have caused confusion, and that a more appropriate label may have been "Adjustments to the Filed Rate Demonstrating Its Continued Justness and Reasonableness."[163]

86. Specifically, DMG points to the Presiding Judge's failure to consider its witness Cox's testimony regarding underrecovery of the heating losses component and how the Commission recently has deemed the use of locational marginal pricing (LMP) appropriate. According to DMG, the Commission should consider this evidence when determining the overall justness and reasonableness of DMG's filed rate.[164] DMG cites to its use of LMP pricing as part of its supplemental information, explaining that it was not used in the filed rate because LMP pricing was not available until April 1, 2005, noting that if it re-filed today, it would use LMP pricing. According to DMG, the Presiding Judge improperly excluded its recalculation of heating losses.[165]

3. <u>Opposing Exceptions</u>

87. Trial Staff argues that DMG had the option of filing the supplemental information as a separate section 205 proceeding, but elected not to do so, and the Presiding Judge "properly" did not consider it.[166] According to Trial Staff, the fact that DMG did not file the supplemental information as a revised rate filing "bears strong witness to its

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[162]Id. at 12-14 (citing Houlton Water Co. v. Maine Public Serv. Co., 55 FERC ¶ 61,037 (1991) (Houlton)).

[163]*Id.* at 11.

[164]*Id.* at 17-18.

[165]*Id.* at 12.

[166]Trial Staff Brief Opposing Exceptions at 3.

irrelevance."[167] Moreover, Trial Staff asserts that the Presiding Judge correctly determined that the supplemental information included "an 'implausible and hypothetical' increase in heating losses without providing other [p]articipants the opportunity to respond."[168] Trial Staff claims that the subsequent filing made substantive changes to the filed rate, abandoning the cost of capital analysis in the filed rate schedule and incorporating an inapplicable generic rate of return.[169]

88. Additionally, Trial Staff asserts that the Presiding Judge was correct in finding that, even under *Houlton*, a finding that one component is unjust or unreasonable can make the entire rate unjust and unreasonable if that component is a substantial portion of the overall rate.[170] Trial Staff adds that the Presiding Judge has no obligation to review evidence determined to be "'irrelevant.'" A requirement to do so would "eviscerate the Presiding Judge's discretion to accord the appropriate weight to the evidence in the record."[171]

89. Illinois Power also challenges DMG's position that the Presiding Judge erroneously ignored evidence of cost under-recovery in the supplemental information.

4. Commission Determination

90. Contrary to the finding of the Presiding Judge, we find that DMG's supplemental information is relevant to our determination of whether its existing rate remains just and reasonable and we will accept DMG's supplemental information into the record.[172] While DMG referred to the filed data as a "New Rate Filing," we view that nomenclature as misleading since, as DMG itself states, it did not file it with the Commission under section 205. Accordingly, we find that the supplemental information is essentially cost

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

[168] *Id.* at 6.

[169] Id.

[170] *Id.* at 7-8.

[171] Id.

[172] Under Rule 505 of the Commission's Rules of Practice and Procedure, "a participant has the right to present such evidence . . . as may be necessary to assure true and full disclosure of the facts." 18 C.F.R. § 385.505

support to demonstrate that the filed rate is just and reasonable and we will allow it to be included in the record for that purpose. In fact, certain unopposed adjustments, including a tax calculation correction, correction for depreciation, revision to plant net book value, correction to the reactive cost allocator for Vermilion, a pound per square inch gauge pressure revision, recognition of the Baldwin Unit 2 generator rewind, and an adjustment to the Hennepin Unit 2 reactive capability limit[173] were affirmed by the judge.[174] With respect to those unopposed adjustments to the as-filed rate, we affirm the Presiding Judge.

H. Other Issues

91. To the extent that the Presiding Judge made other determinations to which no exceptions have been filed and that have not specifically been addressed above, we summarily affirm the Presiding Judge's determinations for the reasons set forth in the Initial Decision. Further, we direct DMG to file a compliance filing within 30 days of the date of this order that sets forth a revised revenue requirement reflecting the Commission's findings herein. We also direct DMG to make any necessary refunds and file a refund report, as ordered below.

The Commission orders:

(A) The Initial Decision is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) DMG is hereby directed to file, within 30 days of the date of issuance of this order, revisions to its rate schedule reflecting the Commission's findings herein.

(C) Within 45 days of the date of issuance of this order, DMG is hereby directed to make refunds from the refund effective date, June 7, 2005, through September 7, 2006

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[173] In addition, DMG conceded that an adjustment for accumulated deferred income taxes was appropriate, and the Presiding Judge found that it was appropriate to lower DMG's revenue requirement to account for accumulated deferred income taxes as recommended by Trial Staff.

[174] Statements to the contrary notwithstanding, Trial Staff and Ameren were given an opportunity to submit rebuttal testimony on March 30, 2006 after DMG filed its cost support in January 2006.

(the 15-month refund period), with interest calculated in accordance with 18 C.F.R. § 35.19a (2007), and to file a refund report with the Commission within 15 days of the date refunds are made. If no refunds are due, DMG is hereby directed to file with the Commission, within 45 days of the date of issuance of this order, a report so stating.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Acting Deputy Secretary.