RÉPONSE DU TRANSPORTEUR
À LA DEMANDE DE RENSEIGNEMENTS NUMÉRO 1
D'OPTION CONSOMMATEURS (OC)

Réponse R75.a

Opinion 440 de la FERC

88 FERC ¶ 61,141

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 440

American Electric Power Service Corporation) Docket No. ER93-540-006

OPINION AND ORDER AFFIRMING IN PART AND REVERSING IN PART INITIAL DECISION

Issued: July 30, 1999

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	))	Docket No. ER93-540-006

OPINION NO. 440

APPEARANCES

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

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(Issued July 30, 1999)

I. **INTRODUCTION**

This proceeding is before the Commission on exceptions to an Initial Decision issued in this proceeding on August 7, 1997 (Initial Decision). 1/ In this order, with certain enumerated exceptions, we affirm the findings of the presiding administrative law judge (judge).

II. **BACKGROUND**

This proceeding began when American Electric Power Service Corporation (AEPSC) 2/ filed a transmission service and ancillary services tariff for Commission approval. The proposed tariff offered firm point-to-point transmission service, for periods as short as one month, to any "eligible utility" as defined therein. The Commission accepted the proposed tariff for filing, suspended its effectiveness and made it subject to refund, summarily disposed of certain matters, and set for hearing the justness and

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1/ American Electric Power Service Corporation, 80 FERC ¶ 63,006 (1997).

2/ AEPSC filed the application on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company (collectively "AEP"). AEPSC is a service subsidiary of AEP.

reasonableness of the proposed rates. 3/ Requests for rehearing and clarification were filed by the AEP companies and others. 4/

In its rehearing order, the Commission announced a new "comparability" standard pertaining to open access transmission tariffs. Namely,

> an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system. [67 FERC at 61,490.]

The Commission also ordered that an evidentiary hearing be held on whether the proposed tariff was unduly discriminatory and/or anticompetitive (i.e., regarding AEP's uses of its system, any impediments or consequences of offering comparable service to others, and the costs incurred by AEP in using its transmission system). Id. at 61,490-91.

Before hearings were held, on March 29, 1995, we issued a Notice of Proposed Rulemaking in our open access rulemaking proceeding ("Open Access NOPR") in which we proposed to require all public utilities owning facilities for the transmission of electric energy in interstate commerce to file open-access transmission tariffs. 5/ Attached to the Open Access NOPR were two pro-forma tariffs that set forth the non-price terms and conditions of open access point-to-point and network transmission service. We also issued a pair of orders providing guidance on the disposition of this docket and other pending transmission

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3/ American Electric Power Service Corporation, 64 FERC ¶ 61,279 (1993), order on reh'g and clarification, 67 FERC ¶ 61,168 (1994).

4/ Requests for rehearing or clarification were filed by AEP, Industrial Energy Users-Ohio, American Municipal Power-Ohio Inc. (AMP-Ohio) jointly with Indiana Municipal Power Agency (IMPA), Blue Ridge Power Agency (Blue Ridge), Wabash Valley Power Association, Inc. (WVPA), West Virginia Power Division of UtiliCorp United Inc. (West Virginia Power), and D.C. Tie, Inc. (DC Tie).

5/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514 (1995).

tariff proceedings. 6/ In the Supplemental Guidance Order, public utilities such as AEP, which then were litigating the terms and conditions of comparability, were given the option of revising their tariffs to be consistent with the *pro forma* tariffs. Upon notice of the filing of such tariffs, the existing proceedings in the pending rate cases were to be held in abeyance awaiting a determination by the Commission of whether there were any genuine issues of material fact warranting further hearing procedures.

The parties in this proceeding held settlement discussions that resulted in a partial settlement that the judge certified to the Commission as a partially contested settlement. AEP's proposal to adopt the non-price terms and conditions of the *pro forma* tariffs was certified as uncontested. 7/ On February 14, 1996, the Commission issued an order on the partially contested settlement in which we approved AEP's proposal to adopt the non-price terms and conditions of the *pro forma* tariff, with certain minor modifications proposed by an intervenor and not disputed by AEP. 8/ The Commission also approved the remainder of the settlement (*i.e.*, the pricing aspects) with respect to the participants that did not oppose the settlement. With respect to the remaining participants, the Commission remanded the contested issues to the judge for further proceedings, as deemed necessary, and for preparation of the Initial Decision. 9/

6/ American Electric Power Service Corporation, *et al.*, 70 FERC ¶ 61,358 (1995) ("Guidance Order"), *order on reh'g and clarification*, 71 FERC ¶ 61,393 (1995) ("Supplemental Guidance Order"). In the Supplemental Guidance Order, the Commission provided for abbreviated filing requirements, less case-by-case litigation, and an expedited approval process for utilities such as AEP, that had voluntarily filed non-discriminatory open access transmission tariffs.

7/ The Open Access NOPR proposed "*pro forma* tariffs." Order No. 888, issued on April 24, 1996, *see* note 10 *infra*, adopted a single *pro forma* tariff. The AEP partial settlement references "pro forma tariffs" because it pre-dates issuance of Order No. 888.

8/ American Electric Power Service Corporation, 74 FERC ¶ 61,132 (1996).

9/ *Id.* The order identified the remaining participants as AMP-Ohio, IMPA, Blue Ridge, the Cities of Cleveland and Hamilton, Ohio (Cleveland and Hamilton), the Indiana Office of Utility Consumer Counselor (IUCC), DC Tie, Electric Clearinghouse, Inc. (Electric Clearinghouse), WVPA, and West Virginia Power (collectively, intervenors).

While these proceedings were pending, the Commission issued Order No. 888. 10/ In response to Order No. 888, AEP submitted a revised open access transmission tariff 11/ that superseded the instant tariffs, but which used the same transmission and ancillary service rates at issue in this proceeding.

In response to the Commission's directive in its order on the partial settlement, the judge established additional procedures leading to a "paper hearing" on the remaining issues. The additional procedures included additional discovery, the filing of additional testimony by trial staff, intervenors, and AEP, the filing of a revised Joint Statement of Issues, and the filing of briefs before the judge and the Commission.

III. DISCUSSION

A complete list of the litigated issues was presented in the Joint Statement of Issues, and are listed in the Initial Decision. 80 FERC at 65,045-46. In the discussion below, we will focus on the contested issues and those where we reverse the findings in the Initial Decision. 12/

We summarily affirm the Initial Decision on the following issues: (1) credits for customer-owned facilities; 13/ (2) the "long generator leads" and "generator outlet lines" used for AEP

10/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (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).

11/ On July 31, 1997, the Commission accepted the compliance filing for filing, effective July 9, 1996, subject to revision to reflect the outcome of the instant proceeding. Allegheny Power Systems, Inc., et al., 80 FERC ¶ 61,143 at 61,557 (1997).

12/ Our listing of the issues (in the table of contents) generally conforms with the issues identified by the judge in the Initial Decision.

13/ No party filed exceptions to the judge's finding that this issue is beyond the scope of this proceeding. 80 FERC at 65,054.

generation; 14/ (3) the depreciation and non-income tax components of the carrying charge; 15/ (4) the revenue credit flow through; 16/ (5) the Indianapolis Power and Light Sale; 17/ (6) the system sales and buy-sell transactions; 18/ (7) the one mill adder; 19/ (9) Reactive Supply and Voltage Control (VAr) - Refunctionalization of transmission investment; 20/ (10) VAr - Generator and Exciter Systems Costs; 21/ (11) VAr - Accessory Electric Equipment Costs; 22/ (12) VAr - Other Power Production

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14/ The judge stated that the issue of credits should be addressed when a customer requests service. 80 FERC at 65,057. The judge also noted that the Commission determined that the Rockport lines serve a transmission function and should be functionalized to transmission. See id. citing American Electric Power Service Corp., 37 FERC ¶ 63,032 (1987), aff'd in pertinent part, 44 FERC ¶ 61,206 (1988).

15/ This issue is moot because we affirm the judge's use of a net plant methodology.

16/ We deny an intervenor's request to note or take official notice of the figures found in AEP's Account No. 456 as reported in AEP's FERC Form No. 1 because they do not fall within the test period.

17/ The Indianapolis P&L sale began after, and was thus not counted in, AEP's single system peak, therefore, the judge did not include this sale in the 1 CP demand divisor. Instead, the judge adopted a revenue credit proposal.

18/ No party filed exceptions to the judge's finding adopting AIW's proposal to use 8,760 hours to develop the hourly unit rate. 80 FERC at 65,062.

19/ No party filed exceptions to the judge's finding rejecting the one-mill adder. Id. at 65,070.

20/ The judge found that AEP does not have to refunctionalize its transmission investment because Order No. 888 established "Reactive Supply and Voltage Control from Generation Sources" as one of the six ancillary services.

21/ The judge found that 24 percent of the investment in turbogenerators represents generators and exciter system costs.

22/ Examples of accessory electric equipment are: control cables, power cables, switching equipment, and station grounding. The judge approved AEP's figure of 10 percent for accessory electric equipment, which are treated in 16
(continued...)

Investment; 23/ (13) VAr - jointly-owned units; 24/ (14) Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response) - CCD Units; 25/ and (15) Energy Imbalances - Charges for Over-Scheduled Power. 26/ We find that the Initial Decision properly decided these issues and the arguments on exceptions have failed to persuade us that the Initial Decision erred or that additional discussion is necessary.

A. TRANSMISSION RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

The issue here is the same as that previously addressed by the Commission in Kentucky Utilities Company, Opinion No. 432, 85 FERC ¶ 61,274 at 62,100-05 (1998) (KU), i.e., whether a levelized or non-levelized rate design is appropriate for developing the companies' rates for unbundled transmission service.

The non-levelized method generally will recover higher costs in the early years of a facility's life and increasingly lower costs in later years. By contrast, the levelized gross plant method will recover costs in equal (or levelized) increments each year of a facility's life.

22/ (...continued) separate sub-accounts.

23/ No party filed exceptions to the judge's finding that 0.15 percent is an appropriate allocation factor for other power production investment.

24/ The judge determined that jointly-owned units are appropriately included in the costs used to determine the VAr charge. The jointly-owned generating units here at issue are owned by Columbus Southern Power Company (an AEP affiliate), along with Cincinnati Gas & Electric Company and Dayton Power & Light Company (collectively, the "CCD" units). See 80 FERC at 65,080.

25/ The judge ruled that "CCD" units are appropriately included in the costs used to determine the spinning reserve charge.

26/ The judge determined that AEP should pay 90 percent of its decremental costs for overscheduled energy outside the bandwidth.

Positions of the Parties

AEP proposed a rate for its transmission service based on the levelized gross plant approach described above. AEP argued that it has used this approach consistently for decades. 27/ AEP further asserted that it did not propose to switch the rate design methodology for any customers other than a subset of existing and potential transmission customers (i.e., requirements customers).

WVPA, IUCC, Blue Ridge, AMP-Ohio, and trial staff argued against AEP's proposed levelized gross plant approach because:

> (1) under AEP's transmission tariff, transmission customers will not be charged rates that are comparable to AEP's own use of its transmission system, and the rates therefore will discriminate against transmission customers in violation of the Commission's comparability standard;
>
> (2) factors that supported the use of the levelized gross plant approach in cases where it was adopted are absent here; 28/ and
>
> (3) given that AEP's system is composed of facilities with varying levels of depreciation, and the levelized gross plant method does not adjust for such depreciation, the levelized gross plant approach would produce excessive revenues for AEP.

Initial Decision

The judge found that AEP's proposed levelized gross plant methodology of calculating transmission rates results in a switch from the non-levelized net plant methodology for its requirements customers, as well as its retail customers. The judge found that, as a result of this switch,

> AEP's requirements customers (as well as retail customers who may switch to transmission service) will be paying depreciation a second time leading to an overrecovery of AEP's costs. [80 FERC at 65,052.]

27/ AEP asserts that, historically, many of its interchange service rates were developed based on the levelized gross plant approach. See Ex. A-101.

28/ For example, in Southern California Edison Company, Opinion No. 341, 50 FERC ¶ 61,138 at 61,412 (1990) (SoCal Edison), and Jersey Central Power & Light Company, et al., 38 FERC ¶ 61,275 at 61,927 (1987) (Jersey Central), the company historically had used the levelized approach.

The judge also found that AEP did not demonstrate that its proposal meets the Commission's comparability standard as set forth in the Commission's Transmission Pricing Policy Statement. 29/ In this regard, the judge explained that AEP uses a non-levelized net plant approach for its native load customers while proposing a levelized gross plant approach for non-native load customers. He concluded that,

> [b]ecause AEP's open access tariff does not offer third parties access on the same or comparable basis [as AEP's use of its system], AEP's levelized approach violates the Commission's comparability standard. [80 FERC at 65,053.]

Moreover, the judge found that Commission precedent does not support AEP's proposal to use the levelized gross plant method for transmission service. In particular, the judge noted that AEP's citations to SoCal Edison and Jersey Central are inapposite because the circumstances in those cases are distinguishable from those present here, where AEP is proposing to switch depreciation methods after nearly one-third of AEP's transmission system already has been depreciated without making adjustments to prevent overrecoveries. The judge found the non-levelized net plant methodology appropriate to design rates for AEP's wholesale transmission service.

Exceptions

AEP filed an exception to the judge's rejection of its proposed levelized gross plant transmission rate design. AEP claims that the judge erred in failing to recognize that: (1) the Commission has previously found that the gross plant and net plant methods recover identical costs over the lives of the assets, and the rate differences between the two methods is simply the result of a timing difference in cost recovery; (2) AEP was not proposing a "change" in its rate design method; (3) AEP's use of the levelized method will not result in an overrecovery of its revenue requirement; and (4) comparability does not require use of the net plant methodology.

Blue Ridge, AI, WVPA, and trial staff filed briefs opposing AEP's exception on this issue.

29/ Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, FERC Stats. & Regs. ¶ 31,005 at 31,141-44 (1994), order on reconsideration, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

Discussion

We deny AEP's exception, and affirm the judge's rejection of AEP's proposed switch to a levelized gross plant rate design. While reasonable results can be produced using either levelized or non-levelized rate methods, depending on the circumstances, see, e.g., KU, 85 FERC at 62,103-05, here we find that, based on the record before us and the circumstances presented in this case, the use of a levelized gross plant rate design by AEP would not produce a just and reasonable result. Specifically, we note that AIW and trial staff witnesses testified that this switch would result in an overrecovery of costs by allowing AEP to recover anew depreciation expense that it has already recovered. See, e.g., Exs. AIW-11 at 24-31; AIW-17; S-71 through S-84. 30/ We are not convinced by AEP's opposing arguments on this issue (e.g., AEP did not provide any studies demonstrating that there would not be higher rates if the levelized method is adopted, and AEP did not substantiate its claims that it will be adding new transmission plant in the future). See Exs. A-53 at 4 and A-100 at 7.

AEP relies on our order in SoCal Edison in support of its use of a levelized gross plant rate design because AEP has historically provided under certain circumstances long-term stand-alone transmission service under levelized rates, a circumstance that AEP states persuaded the Commission to allow requirements customers to be switched to a levelized rate in SoCal Edison. We reject AEP's argument. As we explained in Consumers Energy Company, 85 FERC ¶ 61,100 at 61,366-67 (1998) (Consumers Energy), the approach we took in SoCal Edison is no longer appropriate. We believe that the concerns that led to our decisions in Consumers Energy, and also in KU, 85 FERC at 62,104-05, dictate that we no longer follow SoCal Edison.

As we found in KU, and restated in Allegheny Power Service Corp., 85 FERC ¶ 61,275 at 62,117 (1998) (APS), where a utility proposes to switch from a non-levelized net plant rate design method, "[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method." 85 FERC at 62,103-05. Just as in KU and APS, AEP has not persuaded us here that the switch in current bundled requirements service is appropriate in the circumstances of this case because: (1) AEP's system is composed of facilities with varying levels of depreciation and

30/ AIW and trial staff claimed that AEP's proposed switch in methods would increase the transmission revenue requirement by $44.5 and $61.2 million, respectively. See Joint Statement of Issues at 3; and Exs. S-72 and S-74.

(2) AEP's proposed levelized gross plant method does not account for such variations. 31/

Based on the foregoing, we reject AEP's proposal to develop its transmission tariff rate using a levelized gross plant method, and we will require AEP to recalculate its tariff rates based on a non-levelized net plant method.

As we stated in Consumers Energy, 85 FERC at 61,367, "[i]t is not our intention to prohibit the use of the levelized approach in every instance. As noted at the outset, the Commission believes that a levelized methodology may produce just and reasonable rates under different circumstances." Here, AEP has not persuaded us that its proposed change in approach is appropriate in the circumstances of this case.

2. **Definition of Investment Base**

a. Transmission/Subtransmission "Distribution Use Facilities" Exclusions

Positions of the Parties

AEP asserted that its transmission system is operated on a fully-integrated basis and therefore it included in rate base all of its facilities classified as transmission. A secondary issue involves customer-owned facilities, and AEP did not give a credit for any customer-owned facilities.

AIW 32/ opposed this treatment, arguing that customer-owned facilities with comparable functions to AEP's facilities should be considered part of the grid, and that customers with such comparable facilities should receive credits for their own facilities that function in the same manner as AEP's facilities to integrate loads and resources. AIW claimed that AEP's proposal misdefines the transmission grid for purposes of recognizing which facilities will be deemed part of the

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31/ The judge's third reason (that AEP's proposed transmission tariff does not offer third parties access to its transmission system on a comparable basis to AEP's use of its own system) is no longer applicable.

32/ Earlier in this proceeding, joint testimony was presented by AMP-Ohio, IMPA, and WVPA. The judge referred to them collectively as "AIW." 80 FERC at 65,048. The judge, in the Initial Decision uses this same abbreviation to refer to AMP-Ohio and IMPA. To clarify when WVPA is not being referred to, we will refer to AMP-Ohio and IMPA together as "AI" and will use "AIW" when referring collectively to AMP-Ohio, IMPA, and WVPA.

transmission grid, and for purposes of establishing a rate for the use of the transmission owners' facilities. AIW argued that the Commission must define the grid in one of two ways, and that under either definition AEP's approach here must be rejected. First, AIW asserted that the Commission could define the grid broadly to include all facilities that are actually used to provide service under AEP's tariff. 33/ Alternatively, AIW stated that the Commission could adopt a narrow definition of the grid that encompasses only the backbone transmission facilities that are necessary to carry any party's power from a delivery point to a receipt point on bulk transmission facilities. AIW contended that if this definition is adopted, some facilities that AEP includes in its rate base should be removed.

AEP and trial staff argued that the costs of all transmission facilities in both the network and point-to-point tariff should be "rolled-in" in developing the tariff rates. 34/ AEP and trial staff contended that AIW is attempting to insert its claims for a credit for customer-owned facilities into the issue of what is AEP's appropriate rate base for transmission. AEP and trial staff asserted that the issue of what facilities AEP should include in its rate base is different from the issue of what customer facilities are entitled to a credit. Both AEP and trial staff supported the rolled-in approach and argued that the question of credits for customer-owned facilities should not be addressed in this proceeding.

Initial Decision

The judge found that AIW's comparability and other arguments "should be appropriately advanced in a different proceeding." 80 FERC at 65,055. He also rejected arguments by AIW that certain AEP facilities should be eliminated from transmission rate base because they do not serve a network function. Based on these findings, the judge concluded that AEP's rolled-in approach should be adopted.

33/ AIW contended that this definition of the grid would better serve the goal of creating workable competitive power supply markets by eliminating discriminatory transmission pricing and encouraging all transmission owners to participate in regional transmission grids.

34/ Rolled-in transmission rates are based on the costs of the entire transmission system and reflect the fact that, when there is an integrated system, all of the facilities in the system are deemed to contribute to each use of the system.

Exceptions

AI argued on exceptions that, under Order Nos. 888 and 888-A, the standard for inclusion of transmission facilities in rate base is the same standard as for inclusion of customer-owned facilities. AI Brief on Exceptions at 10. That is,

> the Transmission Provider must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. [Id. at 9.]

AI claims that the Initial Decision failed to comply with this standard because it failed to explicitly identify what AEP transmission facilities are providing transmission service to its power and transmission customers and it failed to identify what customer-owned facilities are eligible for credits.

AI further argues that the Commission should provide an "advisory opinion" on the issue of credits for customer-owned facilities. AI Brief on Exceptions at 23-36.

With regard to AI's first point, while AEP agrees that any facilities that are not used and useful in providing transmission service should be excluded from rate base, it maintains that all of the facilities included in its rate base meet that test and are thus properly includable. AEP Brief Opposing Exceptions at 7-8.

Regarding AI's second point, AEP argues that the judge correctly found that this issue is not properly before the Commission in this case. AEP contends that this is confirmed by explicit language in Order No. 888, where the Commission stated that "cost credits related to customer-owned facilities . . . are more appropriately addressed on a case-by-case basis where individual claims for credits may be evaluated against a specific set of facts." Id. at 5, citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743. AEP and trial staff contend that the Commission does not have before it any specific claim for credits for customer-owned facilities and therefore cannot evaluate such a request.

Trial staff also argues that the judge correctly found that the issue of customer credits should be treated when a service agreement is negotiated, and that this issue is beyond the scope of this proceeding.

Discussion

We affirm the judge's finding on this issue with regard to AI's first point. In Kentucky Power Company and Ohio Power Company, 64 FERC ¶ 61,112 at 61,923 (1993) (Kentucky & Ohio), we stated, "[u]nder our pricing policy, it is proper for AEP companies to develop their rates on the basis of a rolled-in, system average for all grid facilities they use for transmission, not just the lines that are at delivery voltage." Accordingly, we agree with AEP's rolled-in approach to rate base and we reject AI's contention that these facilities must be more explicitly identified.

As to AI's second point, its arguments here are the same as those raised to the judge by AIW regarding its eligibility for credits for customer-owned facilities, and we do not find these claims persuasive. As we stated in Order Nos. 888 and 888-A, and in other recent orders, the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis. 35/ As noted by AEP and trial staff, AI identified customer-owned facilities in this proceeding, but did not offer any support to justify a credit for such facilities. Thus, we affirm the judge's findings to accept AEP's rate base without any adjustment for customer credits.

b. Accumulated Deferred Income Taxes - Rockport 2 Plant Sale/Leaseback

Background information explaining this issue was presented in the Initial Decision, where the judge stated that:

> AEP's Rockport 2 plant was sold in 1989 for $1.7 billion and leased back for an initial term of 33 years. The gain from the sale of the plant was deferred and is being amortized, with the related taxes, over the term of the lease. AEP functionalized Accumulated Deferred Income Taxes (ADIT) based on a gross plant allocator. AEP took all of its company-wide ADIT and assigned a portion of them to the transmission function based on a fraction with plant in service related to transmission in the numerator and total plant in service in the denominator. ADIT is used to reduce the investment base for purposes of setting a transmission rate. [80 FERC at 65,055, footnote omitted.]

Positions of the Parties

AIW asserted that it is inequitable and contrary to Commission precedent to include in transmission rate base those costs related to the ADIT associated with the Rockport 2 plant

35/ See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743; Order No. 888-A, FERC Stats. & Regs. ¶ 31,049 at 30,271; and Allegheny Power Systems, 80 FERC ¶ 61,143 at 61,539 (1997).

sale/leaseback (Account No. 190), 36/ but not credit transmission customers with any offsetting gains related to that same sale/leaseback. 37/ Consequently, AIW proposed adjusting the functionalization of ADIT to remove ADIT relating to the Rockport 2 plant sale/leaseback. AIW claimed that the Commission previously addressed the proper ratemaking treatment of the costs and gains associated with the Rockport 2 plant sale/leaseback in Blue Ridge, where the Commission held that "ratepayers . . . are entitled to . . . the entire benefit of the sale/leaseback." 57 FERC at 61,373.

AEP's witness stated that AIW's proposed adjustment is a piecemeal approach and that, if ADIT was uniformly removed from all transmission plant, this would increase transmission plant in rate base by more than $33 million. AEP is quite willing to make this adjustment.

Trial staff agreed with AEP that AIW's proposal should be rejected because it is piecemeal. Trial staff claimed that AIW chose one item (the Rockport 2 plant sale/leaseback) and directly assigned that item to generation, and then used the plant ratio fraction for everything else. Trial staff asserts that this approach is selective and unfair. Trial staff supports AEP's original calculation.

Initial Decision

The judge found that, notwithstanding AIW's arguments to the contrary, Blue Ridge is inapposite here. In Blue Ridge, the Commission held that ratepayers are entitled to the gain from the Rockport sale/leaseback and that the shareholders are not. The issue in that proceeding did not involve ADITs. Conversely, in this proceeding, the issue is the allocation of ADITs among groups of ratepayers. Thus, the judge found that Blue Ridge does not support AIW's position. 80 FERC at 65,055.

Exceptions

AI filed exceptions to the Initial Decision where it raised arguments similar to those raised by AIW before the judge.

36/ Account No. 190 is a rate base addition; thus, by reducing the costs from this account that are included in rate base, the transmission customers' rates will be lowered. See Exs. AIW-1 at 16-17 and AIW-4.

37/ See AI Brief on Exceptions at 36-39, citing Blue Ridge Power Agency, et al. v. Appalachian Power Company, 57 FERC ¶ 61,100 at 61,373 (1991) (Blue Ridge).

AEP and trial staff opposed AI's exception and asserted similar arguments to those they had advanced before the judge.

Discussion

We agree with the judge that AI's reliance on Blue Ridge is misplaced here. In Blue Ridge, we addressed whether ratepayers or shareholders should receive the gain on the Rockport 2 sale/leaseback, 57 FERC at 61,373, while here the issue concerns the proper allocation of ADITs between different groups of ratepayers (i.e., transmission vs. requirements customers). We find that AI is proposing a piecemeal approach that improperly focuses on a change to only one component of ADIT. AI has failed to sponsor an alternative allocation method for ADITs. Thus, we deny AI's exception and affirm the Initial Decision.

c. Generator Step-Up (GSU) Transformers

A GSU transformer is an electrical device that transforms power from a lower voltage to a higher voltage. The GSU transformers in question in this proceeding are those which step-up voltages at the generation level to higher voltages at the transmission level.

Positions of the Parties

AEP maintained that GSUs should be included in transmission rates because they perform a transmission function. AEP also argued that the inclusion of GSUs in transmission rate base is supported by Commission precedent. 38/

AI, WVPA, Blue Ridge, and trial staff argued that part of the function of GSUs is production-related and that AEP should not charge its transmission-only customers production-related costs. These participants also argued that Commission decisions supporting inclusion of GSUs in transmission rate base pre-date Order No. 888 where the Commission required utilities to offer unbundled open access transmission service. Thus, these participants argued that the cost of GSUs should be excluded from AEP's transmission rates.

Initial Decision

The judge approved AEP's proposal to continue recovering the costs of its GSUs through its transmission tariff rates. The judge found (80 FERC at 65,056-57) that this proposal was supported by Commission precedent that provides that the purpose of these facilities is to transform, or step-up, generation for

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38/ AEP cited Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 at 61,352 (1988).

the purpose of transmitting power "in bulk with less loss and at less cost . . . ." 39/ While acknowledging that the precedent he relied on was from the "pre-unbundling" era, the judge nevertheless found it to be on point because, as in the instant case, it involved transmission-only service. The judge further found that trial staff and intervenors failed to counter AEP's assertion that its classification is in accord with the Uniform System of Accounts. 80 FERC at 65,057.

Exceptions

AI, Blue Ridge, WVPA, and trial staff filed exceptions to the Initial Decision raising arguments similar to those they raised at hearing.

AEP opposed each of these exceptions.

Discussion

In the past, the Commission functionalized a utility's entire cost of GSU transformers as transmission-related and allowed the utility to recover these costs through its rolled-in transmission rate. However, in KU we decided to reverse our policy in light of the Commission's unbundling of transmission and wholesale generation services in Order No. 888. As we stated in KU, given our actions in Order No. 888,

> we believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their appropriate share of the cost of services which they use. [85 FERC at 62,111.]

Our reexamination of GSU costs in KU persuaded us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates. Those same findings are applicable here. We therefore reverse the Initial Decision to reflect our revised policy on the recovery of GSU costs, as more fully articulated in KU.

3. **Return on Equity**

After the paper hearing, the parties to this proceeding filed a Stipulation and Agreement (Stipulation) resolving the

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39/ The judge cited Minnesota Power & Light Company, Opinion No. 12, 3 FERC ¶ 61,045 at 61,137 (1978), among other cases, for this proposition.

overall rate of return. 40/ Ex. Jt-3. The parties agreed that the overall rate of return to be used to calculate transmission rates in this proceeding would be 9.33 percent. Id. The judge did not rule on this issue; he neither accepted nor rejected the Stipulation. We accept the stipulated rate of return for the following reasons: (1) it does not exceed the upper bound of the ranges of reasonableness advocated by AEP and trial staff; (2) our analysis indicates that the stipulated rate of return is sufficient to assure confidence in the financial integrity of the company, to allow AEP to attract capital, and to provide investors with an adequate return; and (3) no party filed exceptions to it. Thus, we find that the stipulated overall rate of return is just and reasonable. 41/

4. Revenue Credits v. Demand Divisor Increase

There are two basic "off-system" ratemaking treatments: cost allocation and revenue credit. Cost allocation treats the transaction as part of the system load, with a portion of the system costs allocated to the off-system sale. Under this method, the demand divisor is increased to include the off-system transaction. Revenue crediting does not allocate costs to the off-system sale. Rather, on-system customers receive a credit for the revenues associated with the off-system sales. Thus, the off-system sale is not included in the demand divisor.

Positions of the Parties

As noted by the judge, "[t]his issue concerns whether AEP should increase its non-firm rate divisor to reflect full transmission system capability, which would make revenue crediting for non-firm rates unnecessary." 80 FERC at 65,060.

AEP advocated reflecting the demand of multi-year point-to-point transmission service in the demand divisor, while crediting other transmission revenues against its cost-of-service. Specifically, AEP proposes credits to the cost-of-service for revenues from transmission of electricity by others, interruptible service revenues and system sales revenues related to the transmission function.

40/ The signatories of the stipulation are AEP, AMP-Ohio, IMPA, Blue Ridge, WVPA, Indiana Office of Utility Consumer Counselor, and trial staff.

41/ See Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923); FPC v. Hope Natural Gas Company, 320 U.S. 591, 605 (1944).

AIW opposed revenue crediting, and instead argued that, with respect to non-firm rates, the appropriate cost divisor is transmission system capability as measured by AEP's generating capacity plus firm, long-term transactions. AIW asserted that the use of revenue credits to offset the non-firm revenue requirement is inappropriate because revenues from the use of excess capacity of the transmission system are already accounted for in the demand divisor.

Trial staff opposed both the AEP and AIW approaches, and argued that AEP should include all firm transmission service demand in the demand divisor, and credit only revenues from non-firm transmission service against the cost of service, as this would be consistent with Commission's precedent. Specifically, trial staff contended that its approach is consistent with Order No. 888 wherein the Commission stated that it would allow point-to-point firm transmission rates to be based on adjusted monthly system peak loads, which it defined as:

> the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service. [42/]

Initial Decision

The judge found that trial staff's proposed method was supported by the provisions of Order No. 888. He therefore adopted trial staff's proposal stating that:

> a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes. [43/]

Exceptions

AI filed exceptions to the judge's findings, arguing that the judge failed to address its proposal that the denominator for this service should be set at an amount equal to "AEP's generating capacity plus firm contract demands." AI Brief on Exceptions at 53. In essence, AI contends that: (1) the Commission recognizes that most non-firm service is less valuable

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42/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

43/ 80 FERC at 65,061, citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

and should be priced below the level of firm service; and (2) this should be accomplished through the use of a larger divisor, and therefore a lower rate.

AEP and trial staff oppose AI's exception. Trial staff agrees with AI's first contention, but not the second. Trial staff states that where the non-firm rate is a ceiling, or "up-to" rate capped at the firm rate (as here), the Commission has consistently allowed this treatment. Trial staff contends that the use of the same divisor for both non-firm and firm services and capping the non-firm rate at the firm rate is consistent with Commission precedent, the Commission's Pricing Policy Statement, and Order No. 888. 44/

Discussion

We reject AI's argument that the Initial Decision did not squarely address its proposal. As noted by the judge, we resolved this issue in Order No. 888, where we concluded that it is appropriate for non-firm service to be priced using up-to rates with the ceiling rate set at the firm service rate. 45/ In addition, we agree with trial staff that AEP should include the demand for all firm transmission service in the demand divisor, and only credit revenues from non-firm transmission against the cost of service. Thus, we conclude that AI's exceptions raise no arguments not already considered and rejected by the judge, and we affirm the findings of the judge on this issue.

5. **Demand Divisor**

This issue involves the development of the demand divisor for firm transmission rates.

Background

Initially, AEP proposed a non-customer-specific firm point-to-point transmission rate based on a 12 CP demand divisor. 46/

44/ Trial Staff Brief Opposing Exceptions at 58-60, citing, e.g., Central Maine Power Company, 54 FERC ¶ 61,206 at 61,612 (1991); Transmission Pricing Policy, FERC Stats. & Regs. ¶ 31,005 at 31,137 (1994); and Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

45/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

46/ 64 FERC at 62,977. Demand allocation determines the charge allocated to a class of customers. Under the 12-month coincident peak method, commonly known as the 12 CP method, demand is allocated by taking the hour of highest usage (the (continued...)

In our order setting AEP's filing for hearing, we summarily rejected AEP's proposal, citing our precedent in Southern Company Services, 61 FERC ¶ 61,339 (1992) (Southern). We gave AEP the option of developing a "customer-specific" rate by allocating AEP's total transmission-related revenue requirement using a customer-specific revenue requirement using those customers' 12 coincident peaks and billing determinants, or to develop a non-customer-specific rate using a 1 CP demand divisor. AEP elected to maintain its non-customer specific approach, but nonetheless filed a request for rehearing, asking us to allow it to use a 12 CP demand divisor in conjunction with a non-customer-specific revenue requirement. We denied rehearing on this issue and directed AEP to use the annual system peak (1 CP) as the demand divisor. 67 FERC at 61,487. AEP complied with the Commission order and filed a 1 CP demand divisor. 47/ AEP did not file a petition for review of the Commission's orders.

Positions of the Parties

Notwithstanding that the issue was rejected by summary disposition and was not set for hearing, AEP attempted to preserve and litigate this issue at hearing and continued to advocate a 12 CP demand divisor throughout the proceeding. AEP argued that in Order No. 888 the Commission changed its policy with respect to the use of a 12-CP demand divisor when a tariff allows full flexibility for point-to-point service. AEP contended that its tariff (filed in connection with its offer of settlement and Order No. 888) allows this full flexibility, and the use of a 12 CP demand divisor is thus appropriate. AEP Initial Brief at 26-27.

Initially, trial staff supported AEP's request to use a 12 CP allocator based largely on the reasons given by AEP. Trial staff argued that Commission precedent supports the use of a 12 CP divisor when the average of the 12 monthly peaks to the single peak is more than 84 percent of the single system peak. Trial staff asserted that this average for AEP's system is 89.9 percent. Trial Staff Initial Brief at 49.

46/ (...continued)
coincident peak) in twelve consecutive months, determining the percentage of peak use by each customer class during each of the twelve months, and averaging the resulting percentages for each customer class. By contrast, the 1 CP method allocates demand among customer charges based on the annual coincident peak.

47/ AEP proposed a 1 CP demand divisor of 17,753 MW, reflecting its 1992 internal peak minus its interruptible loads and generator direct loads, plus 1,258 MW of firm contract demand. Ex. A-22.

AIW argued that the Commission's orders setting this proceeding for hearing summarily dismissed the 12 CP divisor as an issue in this proceeding. Thus, AIW asserted the adoption of a 12 CP rate at this late date would be both unfair and legally impermissible in this proceeding. Blue Ridge and WVPA also argued that the 12 CP v. 1 CP issue is no longer within the scope of this proceeding.

In addition to opposing AEP's 12 CP proposal on procedural grounds, intervenors also opposed the method AEP used to develop its 1 CP divisor. AIW argued that AEP's 1 CP calculation should be adjusted to include: (1) an additional 329 MW of demand associated with long-term transmission contracts; (2) 890 MW of generator direct loads served by AEP; 48/ and (3) the Buckeye Power Cooperative (Buckeye) load as a long-term load. 49/

Blue Ridge and WVPA argued that the peak demand used as the divisor should be 35,000 MW, which is the projection of AEP's transmission system capability. Blue Ridge and WVPA base this argument on a technical paper prepared by an AEP engineer stating that the system was designed to serve an expected load of 35,000 MW. 50/ However, if this approach is rejected in favor of using an annual system peak, then alternatively Blue Ridge advocated using AEP's 1993-94 winter peak (25,194 MW). Blue Ridge

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48/ AIW and trial staff argued that another 890 MW should be added to AEP's 1 CP demand divisor to reflect certain generator direct served loads (two specific retail loads, see AEP Brief Opposing Exceptions at 22), because the transmission facilities serving the two specific retail loads are routinely included in AEP's transmission planning and load flow studies. Exs. S-72; AIW-20; and AIW-11 at 39-43.

49/ AEP opposed including in the demand divisor firm transmission service AEP provides to Buckeye. AEP acknowledged that this is a resource/load integration type transaction, but it then argued that this transmission should not be included in the demand divisor because resource/load integration type service is not offered under its open access tariff. Ex. AEP-55. AIW argued that AEP's position is no longer valid because AEP is now offering network integration service. Therefore, AIW contended that the Buckeye loads should be included in the demand divisor. Ex. AIW-11 at 38-39. The Buckeye load is 937 MW, which AEP included as load for purposes of a 12 CP divisor.

50/ By comparison, the judge found that the single system peak during the test year was 18,598 MW (80 FERC at 65,064) and AEP's highest system peak occurred in 1993-1994, when total load reached 25,174 MW (80 FERC at 65,065).

contended that this peak represents AEP's proven transmission system capability, and is "a more credible proxy for transmission system capability than use of a test year peak exceeded in prior or subsequent years." Blue Ridge Initial Brief at 18.

Initial Decision

The judge noted that the Commission had considered the issue of 1 CP vs. 12 CP in both its hearing order and its order on rehearing in this proceeding, and that the Commission had rejected AEP's proposed use of the 12 CP method in both instances. The judge also found that, while Order No. 888 now allows utilities to use a 12 CP demand divisor in their point-to-point tariffs, it did not mandate the use of this method. Thus, the judge rejected AEP's proposed 12 CP methodology. 80 FERC at 65,066. 51/

The judge found the appropriate divisor to be 17,753 MW as calculated by AEP using a 1 CP demand divisor. The judge rejected Blue Ridge's contention that the peak should be based on the 1993-94 winter peak because the proceeding is based on 1992 test year costs.

Exceptions

While supporting the Initial Decision's adoption of a 1 CP approach, Blue Ridge filed exceptions arguing that the judge erred by relying on AEP's test-year peak figures to obtain the demand divisor and by failing to consider alternatives suggested by Blue Ridge and other interveners. In particular, Blue Ridge argues that the judge failed to consider peak loads subsequent to the test year (e.g., the 1993-94 winter peak) as a measure of system capability. Blue Ridge argues that consideration of these loads would yield a demand divisor of 25,194 MW, an amount that Blue Ridge claims represents AEP's proven transmission capability. 52/

AI and WVPA filed exceptions to the Initial Decision reiterating the arguments they made before the judge in support of their proposed 1 CP divisor.

AEP also filed exceptions to the Initial Decision and argues that the Commission is not legally precluded from using a 12 CP

51/ The judge did not dispute that AEP may propose a 12 CP methodology in future proceedings, but agreed with AIW that this would require a new section 205 filing.

52/ Blue Ridge Brief on Exceptions at 12-15. This figure is the highest monthly peak demand AEP had reached as of the date Blue Ridge filed its initial testimony.

divisor, and that the evidence AEP has submitted here supports the use of a 12 CP divisor.

Trial staff filed exceptions to the judge's method of calculating the single peak, arguing that it is inconsistent with both Order No. 888 and the methodology adopted by the judge in the Initial Decision. 53/ Trial staff further argues that the rationale underlying the 1 CP figure adopted by the judge is inconsistent with the determinations reached by the judge elsewhere in the Initial Decision. 54/ Trial Staff Brief on Exceptions at 20-24. However, trial staff supported the judge's determination that AEP should be precluded, for procedural reasons, from use of the 12 CP divisor in this proceeding. Trial Staff Brief Opposing Exceptions at 29-30.

AEP, AI, WVPA, Blue Ridge, and trial staff filed briefs opposing exceptions.

Discussion

We find AEP's efforts to preserve and litigate this issue at hearing unavailing. We therefore reject AEP's exception advocating the use of a 12 CP divisor, and we affirm the judge's adoption of a 1 CP divisor in this proceeding.

We summarily rejected AEP's 12 CP proposal in both our initial hearing order (64 FERC at 62,976-77) and in our order on rehearing (67 FERC at 61,487). 55/ By summary disposition, we made a final determination resolving this issue and removing the issue from further consideration in this proceeding. Any timely challenge to this final determination would have had to have been made in a petition for review to the U.S. Court of Appeals,

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53/ Trial staff's calculation started with AEP's monthly firm peak load, then subtracted the monthly coincident peaks associated with all firm point-to-point customers and added the monthly contract demand reservations for firm point-to-point service. This results in a 1 CP demand divisor of 19,537 MW.

54/ For example, in his ruling on the treatment of revenue credits, the judge ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

55/ The hearing order also gave AEP guidance on what cost support should be submitted in a new filing seeking the use of a 12 CP demand divisor. 64 FERC at 62,977.

seeking appeal of this determination. However, no such appeal was filed.

Moreover, to allow AEP to pursue this issue now would be unfair to Intervenors who, based on our prior orders, quite properly understood that this issue was no longer within the scope of this proceeding. 56/ Thus, regardless of any subsequent changes in Commission policy, it would be unfair and prejudicial to the other parties -- and a violation of their due process rights -- for us to consider anew the merits of AEP's 12 CP proposal at this late stage of the proceeding. 57/

While AEP correctly notes that in Order No. 888 we revised the policy we earlier had enunciated in Southern (and which we relied on in our earlier orders to dismiss AEP's 12 CP proposal), AEP fails to consider two important factors that relate to this change in policy. First, as noted by the judge, 80 FERC at 65,066, in Order No. 888 we did not give transmission providers an automatic and immediate right to develop their rates using a 12 CP divisor; rather, we stated that commencing with the ordered improvements in the tariff services we would no longer summarily reject filings on this basis but would instead allow transmission providers seeking a 12 CP divisor to make a filing with the Commission supporting such a proposal and to pursue this at hearing. 58/ Following the Commission's issuance of Order No. 888, AEP had the option of filing a new section 205 rate case, seeking Commission approval to use a 12 CP demand divisor in conjunction with non-customer-specific rates. It chose not to do so.

AEP instead chose to continue to raise this issue in the instant proceeding (based on our issuance of Order No. 888), even though Order No. 888 was issued nearly three years after the Commission's hearing order removing the 12 CP issue from this proceeding. However, as discussed above, due to the finality of our decision on this issue in this proceeding, we reject this

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56/ See AI Initial Brief at 56-57; AI Brief Opposing Exceptions at 31-33; WVPA Brief Opposing Exceptions at 15-16; and Blue Ridge Brief Opposing Exceptions at 12-14,

57/ This is true regardless of the judge's decision to receive into evidence AEP testimony in support of a 12 CP proposal. It is within the purview of the Commission, not of the judge, to define the scope of a proceeding and the Commission already had reached a determination on the 12 CP issue when it set this case for hearing before a judge.

58/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,737-38. See also Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,263.

effort. For these reasons, we reject AEP's proposal to allow it to develop its point-to-point transmission rates using a 12 CP divisor.

AEP advocated a 1 CP demand divisor of 17,753 MW, which was adopted by the judge, but, as pointed out by AIW and trial staff, this number is inconsistent with other determinations in the Initial Decision. We reject 17,753 MW as 1 CP demand divisor. Trial staff proposed a 1 CP demand divisor of 19,537 MW, which is derived by adding the following: (1) 16,495 MW - adjusted internal peak load; 59/ (2) 799 MW - for firm contract demand; (3) 1,304 MW - for firm transmission for others; (4) 890 MW - for two specific retail loads; 60/ and (5) 49 MW - for the Indianapolis P&L sale. We adopt trial staff's proposed 1 CP demand divisor with one modification. 61/ We affirmed the judge's decision to treat the Indianapolis P&L sale as a revenue credit; therefore, we modify trial staff's proposal by adopting 19,488 MW (19,537 MW minus 49 MW) as the 1 CP demand divisor.

6. Appalachian Pricing Method Issues

Appalachian pricing is a rate design method approved by the Commission for short-term service expected to be taken only during peak periods. The hourly charge is developed assuming usage of 16 hours a day, five days a week, 52 weeks a year (i.e., 4,160 hours per year) in contrast to the 8,760 total hours in a year. 62/ Under this rate design, 100 percent of the annual cost of service is equally distributed to each of the 52 weeks in a year; 100 percent of the weekly cost is equally distributed to five of the seven days in a week (Saturday and Sunday are off-peak days and are excluded); and 100 percent of the daily (weekday) cost is equally distributed to 16 of the 24 hours in a

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59/ See Exhibit A-24.

60/ Trial staff claimed that the Buckeye load of 937 MW is included in the 1,304 MW. Trial Staff Brief Opposing Exceptions at 34.

61/ We start with AEP's proposed internal peak load of 16,495 MW (item 1). We add to this trial staff's proposed adjustments for long-term firm transmission service (items 2 and 3) and 890 MW (item 4) for two specific retail loads (as argued by AIW and trial staff). We subtract 49 MW (item 5), based on our findings on the Indianapolis P&L sale.

62/ See Appalachian Power Company, 39 FERC ¶ 61,296 (1987) (Appalachian).

day (the other 8 hours are off-peak hours and are excluded). 63/ In addition, to prevent over-recovery, this rate is accompanied by a proviso that no customer can be charged more than the equivalent daily or weekly rate (e.g., charges for hourly usage are capped at the equivalent daily rate). 39 FERC at 61,964-65. The Appalachian rate design method was established on the theory that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. Id. at 61,965.

Positions of the Parties

AEP proposed to use the Appalachian method for developing its hourly and daily transmission rates for short-term transmission service. Trial staff generally supported AEP, arguing that it is appropriate for AEP to develop its on-peak hourly and daily rates using the Appalachian method, but only if it also offers off-peak service with hourly and daily rates developed using seven days for daily service and 8,760 hours for hourly service.

AIW and Blue Ridge contended that the Appalachian method should be abandoned and a pricing method that encourages economically efficient transactions should be used instead. They further contended that trial staff's approach is not sufficient because the only reasonable method for time-differentiation is to reduce the off-peak rates, not to raise the on-peak rate even further above the cost of service (which they claim would be the result of trial staff's proposal). AIW argued that AEP should use system capacity as the denominator to calculate the non-firm rate because they contended that system capacity represents a conservative measure of AEP's actual capability. In addition, an AIW witness proposed a six day divisor for daily service.

Initial Decision

The judge found trial staff's peak/off-peak proposal to be a reasonable adjustment to the Appalachian method for this proceeding. He stated:

> Staff's proposal achieves the Commission goal of recovering [costs] from those who take service at the time of the peak 4,160 hours while off-peak rates are based upon a distribution of annual costs over all 8,760 hours. [80 FERC at 65,069.]

63/ The use of a five day week, 16 hour day and 52 week year results in 4,160 peak hours in a year.

Thus, the judge reasoned, customers using short-term transmission service during off-peak hours do not constrict the system during the critical load period and should pay less than they would under the Appalachian method. Therefore, the judge found that trial staff's proposal would result in just and reasonable rates, and he adopted it. Id.

Exceptions

AI and WVPA claim that the Initial Decision is internally inconsistent because on the one hand it rejects using the Appalachian method in developing hourly rates for short-term transmission system sales and buy/sell transactions, while on the other hand it approves the Appalachian method for non-firm transmission rates. 64/ AI and WVPA argue that the Commission should find that an 8,760 hour year should be used in determining on-peak non-firm hourly rates for both revenue credits and unit rates in the Open Access Tariff. 65/ AEP and trial staff oppose AI's and WVPA's exceptions.

Discussion

The theory behind Appalachian pricing is that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. 39 FERC at 61,965. We have previously determined that Appalachian pricing is not warranted where it has not been shown that 16 hours is a good proxy for total daily usage.

We disagree with AI's and WVPA's contention that the Initial Decision is internally inconsistent because it uses the Appalachian method for non-firm transmission rates but not for certain revenue credits. AI and WVPA are referring to bundled non-firm, short-term system power sales transactions that AEP engaged in during the 1992 test year. AEP reflected a credit of $25.8 million for the transmission component of the non-firm short-term system power sales to which AI refers. These transactions occurred prior to open access. Therefore, AEP did not separately calculate a transmission component for these bundled power sales, but instead estimated a transmission revenue credit, thereby reducing the cost of service by the estimated

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64/ AI and WVPA ask us to compare the judge's finding basing credits for buy/sell and off-system sales on an 8,760 hour test year (which we affirmed summarily, see note 18 supra) to his ruling using a 4,160 hour year for determining the on-peak non-firm transmission rate (80 FERC at 65,068-69).

65/ WVPA Brief on Exceptions at 22; AI Brief on Exceptions at 58-60.

transmission credit. The Initial Decision approved the estimate as reasonable, 80 FERC at 65,062, and we affirm this finding for the reasons stated by the judge. Intervenors have not contended that AEP's proposal would result in unjust and unreasonable rates or in an overrecovery of costs. Instead, they argue it is inconsistent with other findings made in the Initial Decision. As mentioned above, we disagree. Therefore, there is no impediment to accepting AEP's proposal and rejecting the arguments of AI and WVPA.

Accordingly, we affirm the finding of the judge on this issue.

B. ANCILLARY SERVICES RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

Positions of the Parties

AEP recommended using the levelized gross plant methodology to determine rates for ancillary service. AEP explained that its reasoning for using this methodology is the same as discussed for base transmission rates. However, AEP believed that where services are available from third parties, rates should be market-based rather than cost-based. AEP Initial Brief at 32.

AIW argued that ancillary services rates should be developed using non-levelized net plant methodology.

Trial staff argued that three of the six ancillary services -- Regulation and Frequency Response Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service -- are not monopoly services because transmission customers can provide these services and put a downward pressure on the prices offered by AEP. Moreover, trial staff argued that AEP's levelized gross plant rates are "up to" rates that AEP can discount on a non-discriminatory basis. Based on this, trial staff concluded that developing rates for these three ancillary services on a levelized gross plant is not unreasonable.

Initial Decision

The judge found that the non-levelized net plant methodology for developing ancillary services rates is appropriate for the same reasons as discussed with respect to transmission rates.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative and determine that AEP's proposal to price these ancillary services using the levelized gross plant method is reasonable. We have repeatedly approved the use of the levelized gross plant method of pricing as a reasonable approach. Although in this proceeding, as in KU, we have rejected company proposals to use a levelized gross plant method to price transmission tariff rates, this was because these cases involved company proposals to switch pricing methods (from a non-levelized net plant pricing to a levelized gross plant pricing) in mid-stream for what were similar transmission services. It is this switching of methods, and not the levelized gross plant method itself, that we find has led to the development of rates that have not been shown to be just and reasonable. Conversely, here there is no switching of methods involved because these ancillary services are new services that were not previously provided as separate services. This is a key distinction that makes the KU precedent on the pricing of transmission rates inapposite here.

For these reasons, and because no party has shown that the ancillary rates produced by AEP's levelized gross plant method are otherwise unjust, unreasonable or unduly discriminatory, we adopt AEP's pricing approach.

2. Scheduling, System Control and Dispatch Service

We agree with the judge that there are no remaining issues involving this ancillary service. 80 FERC at 65,071. Ex. Jt-1 at 21. The per unit rates will be affected by the cost divisor ultimately found just and reasonable, which we find is the same divisor we found proper for the base transmission rate -- 19,488 MW. See section III.A.5 above.

3. Reactive Supply and Voltage Control (VAr)

a. Active and Reactive Allocation Factor

Positions of the Parties

AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function." AEP Initial Brief at 37. While both AEP and trial staff generally agreed on the methodology to calculate allocation factor applicable to reactive production, 66/ they disagreed on the location at which the reactive capability should be measured. Depending on the measuring point location chosen, costs will be shifted between customers taking transmission service and native load customers. AEP asserted that the name-plate reactive capability at the generator terminals should be used. 67/ Trial staff explained that some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs, before it reaches the transmission system. 68/ Accordingly, trial staff argued that the Commission should not use the generator's nameplate reactive capability, but instead should use the reactive capability at the GSU terminals available to the transmission system. Ex. S-88. Thus, while AEP proposed a reactive power allocation factor of 21 percent, trial staff recommended only 11.47 percent.

AEP, however, maintained that the GSUs should remain a part of the transmission system. Also, even if GSUs are functionalized to production, AEP argued that despite the reactive power losses associated with auxiliary loads and GSUs, the 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. AEP Reply Brief at 43.

Initial Decision

The judge found merit in AEP's argument that there must be enough reactive power remaining at the transmission terminal to provide the voltage control support on the system. Accordingly, he determined that AEP's proposed 21 percent allocation factor for reactive power measured at the generator terminals was just and reasonable. 69/

66/ The parties agreed to use the formula $MVAr^2/MVA^2$ to determine the allocation factor.

67/ AEP maintains that reactive capability should be measured at generator terminals (the low-voltage side of the GSU), while trial staff maintains that it should be measured at the GSU terminals nearest to the transmission system (the high-voltage side of the GSU).

68/ As noted earlier, trial staff argued that the GSUs should be refunctionalized to production.

69/ 80 FERC at 65,079. The judge found that the GSUs perform transmission functions. Id. He therefore did not reach trial staff's contentions that relied on the facilities (continued...)

Exceptions

Trial staff filed exceptions arguing again that, during the step up of power and energy from the generator terminal voltage to transmission voltage, some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs. In its exceptions, trial staff reiterates its position that the critical issue here is whether GSUs perform a transmission function or a generation function. Trial staff argues that the judge erroneously determined that the GSUs should be assigned to the transmission function, and that, consequently, the reactive power losses in the GSUs belong to the transmission function. However, trial staff contends that the judge's finding was erroneous. Trial staff states that, in the event the Commission reverses the judge on GSUs, it should adopt the trial staff's reactive power allocation factor of 11.47 percent. Trial Staff Brief on Exceptions at 32-33.

In its Brief Opposing Exceptions, AEP disagrees with trial staff's contention that the functionalization of GSUs to transmission or production is controlling on this issue because the allocation factor is based on capability. AEP argues that, irrespective of the location at which reactive power capability is measured, the generating equipment 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. AEP Brief Opposing Exceptions at 37-38.

Discussion

We adopt the judge's finding that 21 percent is the appropriate allocation factor to segregate the costs of reactive (VAr) production from those of active (Watt) production. We are not persuaded by trial staff's assertion that the reactive capability of the generators should be reduced by the VArs consumed by GSUs and auxiliary loads before developing an allocation factor. We agree with AEP (and the judge) 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

69/ (...continued)
being deemed to perform generation functions.

system. 70/ See AEP Reply Brief at 43. For these reasons, and for the reasons stated by the judge in the Initial Decision, we affirm the judge's ruling on this issue in the Initial Decision.

b. Unrelated O&M Expenses

Positions of the Parties

AEP proposed to include all O&M expenses that are directly and indirectly related to the production of reactive power in its carrying charge rate 71/ of 22.1 percent. AEP claimed that its methodology excludes O&M expenses unrelated to reactive power production. Exs. A-28 at 1; and A-95. Trial staff agreed. Trial Staff Reply Brief at 39.

AIW argued that AEP's method will lead to an overrecovery of its O&M expenses because in developing its carrying charge, AEP improperly included costs from O&M accounts that have no direct relation to the production of reactive power. AIW also argued that AEP's method allocates O&M expenses on a different basis than it allocates plant costs related to VAr production. In addition, AIW argued that AEP should remedy the problem by performing an account-by-account analysis of which O&M costs are actually related to the production of reactive power, and that only those costs should be included in the development of the fixed charge rate. Ex. AIW-11 at 58. AIW Initial Brief at 70-71.

AEP disagreed with AIW's argument that O&M expenses indirectly related to production equipment should be excluded from the development of the carrying charge rate because they do not directly contribute to reactive power production. AEP Initial Brief at 39-40. AEP further stated, "[t]here is no production equipment [that] does not contribute to reactive power production." Ex. A-53 at 43.

Initial Decision

The judge ruled that AIW's method of allocating O&M expenses related to reactive power production is superior to AEP's method because AIW logically assigned O&M expenses to the VAr producing equipment in the same proportion as its investment in such equipment. The judge found that AEP had not justified why O&M

70/ However, we will require AEP to recalculate the transmission loss factor to exclude real power losses that take place in GSUs.

71/ Carrying charge is a component of revenue requirements that provides for the return of and on capital invested in plant, taxes, and insurance premiums.

expenses related to VAr production should be allocated on a different basis than the plant costs related to VAr production, and he thus rejected AEP's proposal (which would have produced higher rates). The judge found AIW's approach to be reasonable because it provided for a consistent treatment of the plant costs and O&M expenses related to VAr production. The judge also found that AEP's argument (that there is no production equipment that does not contribute to reactive power production) is unavailing because the issue here does not concern the total exclusion of the O&M expenses from the VAr charge, but instead involves the proper allocation of O&M expenses to the VAr charge. However, the judge noted that in accordance with his ruling that the non-levelized net plant method is appropriate for developing ancillary services rates, the issue of allocation of O&M expenses is moot because there will be no carrying charge under the non-levelized method. 80 FERC at 65,081-82.

Exceptions

No party filed exceptions on this issue.

Discussion

In accordance with our ruling approving AEP's use of a levelized gross plant rate design for developing the ancillary services rates, the proper allocation of reactive power O&M expenses is no longer moot. We affirm the judge's finding that AIW's method of allocating reactive power O&M expenses is superior to AEP's method for the reasons stated in the Initial Decision.

4. **Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response)**

a. Pricing for Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service

Positions of the Parties

AEP proposed to allocate the minimum East Central Reliability Council (ECAR) requirement of a 6 percent operating reserve level as follows: 1.5 percent for Regulation and Frequency Response Service; 1.5 percent for Spinning Reserve Service; and 3 percent for Supplemental Reserve Service. AEP Initial Brief at 40-41.

While no party took issue with AEP's allocation of 3 percent for Supplemental Reserve Service, trial staff, AIW, and IUGC disagreed with AEP's method of dividing the 3 percent ECAR minimum Spinning Reserve in equal amounts between Regulation and

Frequency Response and Spinning Reserve. 72/ Noting that there are no industry guidelines available on this matter, and that AEP failed to provide data to track moment-to-moment variations (which would have enabled the parties to more accurately allocate this 3 percent figure), trial staff developed its own 4-step method based on AEP's hour-to-hour load deviations. In developing its 4-step method, trial staff made four "simplifying assumptions." 73/ Using that method, trial staff calculated 1 percent for Regulation and Frequency Response Service and 2 percent for Spinning Reserve Service. 74/ AEP opposed trial staff's proposed allocation and methodology, contending that several of the underlying assumptions made by trial staff served to understate the amount of capacity needed for regulation and frequency response service to follow load.

Initial Decision

The judge rejected AEP's criticism of trial staff's approach as conclusory and found that AEP neither provided data to track moment-to-moment variations nor any evidence to support its claim that trial staff's estimate for regulation and frequency response service was understated. The judge also noted that although AEP stated in its Initial Brief that it would discuss this issue in detail in its Reply Brief, AEP's Reply Brief does not even address operating reserves. AEP Initial Brief at 41. The judge then held that until a standard is developed and endorsed by the Commission, trial staff's formula is reliable to calculate the level of Regulation and Frequency Response Service for AEP. Thus, the judge allowed AEP to recover 1 percent of its production costs for the provision of Regulation and Frequency Response Service and 2 percent for the provision of Spinning Reserve Service.

Exceptions

AEP filed exceptions to the judge's decision and argues that trial staff's four "simplifying assumptions" are not representative of actual AEP operating conditions. AEP asserts that, in addition to a Spinning Reserve requirement of three

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72/ The parties agreed that AEP carries a total of 6 percent of capacity to provide for the following three ancillary services: (1) Regulation and Frequency Response Service, (2) Spinning Reserve Service, and (3) Supplemental Reserve Service.

73/ Trial staff's "simplifying assumptions" are described in Trial Staff's Brief Opposing Exceptions at 40.

74/ Trial Staff Initial Brief at 65. AI Initial Brief at 71. IUCC Initial Brief at 30-31.

percent, an additional three percent is required for Regulation and Frequency Response Service merely to follow the load trend (for a total of six percent). Nevertheless, AEP proposes only to recover a Regulation and Frequency Response Reserve of 1.5 percent and a Spinning Reserve of 1.5 percent (for a total of three percent). AEP Brief on Exceptions at 34.

Trial staff argues that a proper breakdown between Regulation and Frequency Response Service and Spinning Reserve Service is important because a customer has fewer options available for obtaining Regulation and Frequency Response Service. Trial staff points out that while both services can be obtained from a source other than the transmission provider, Regulation and Frequency Response Service can only be provided by generators that are operated under Automatic Generation Control or some NERC-approved method that enables the generator to instantaneously follow load, thus creating technical limitations on a purchaser's ability to obtain this service from a provider other than the transmission provider. Trial staff argues that such limitations do not exist for competitively obtaining Spinning Reserve Service. Trial Staff Brief Opposing Exceptions at 36-43.

Discussion

We reverse the judge and, based on the evidence presented in the record, approve AEP's proposal that the pricing of Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service should be allocated based on 1.5 percent, 1.5 percent, and 3.0 percent of production costs, respectively. As noted above, there were no industry guidelines for the pricing of these ancillary services at the time this case was litigated, and thus AEP attempted to allocate the ECAR minimum requirement among these services. No participant has demonstrated that AEP's proposal is unreasonable, and indeed, the fact that the different approaches used by AEP and trial staff each produces a combined rate of 3.0 percent for Regulation and Frequency Response Service and Spinning Reserve Service corroborates the reasonableness of AEP's overall end result, based on the evidence presented in the record. AEP is only required to show that its proposal is reasonable; not that its proposal is the only reasonable result on this record, or that its proposal is superior to all other proposals. 75/ For these reasons, we adopt AEP's proposal.

b. Other Production Facilities

Positions of the Parties

AEP did not seek to include GSUs in developing its ancillary services rate because it included GSUs in developing its base transmission rate. However, trial staff argued that GSUs are used in providing generation-based ancillary services to transmission customers, and therefore, the cost of GSUs should be included in the rate for those ancillary services. 76/ Trial Staff Initial Brief at 72-73. AIW opposed trial staff's proposal to include GSUs in the charges for AEP's generation-based ancillary services, arguing that these services are provided at the generation bus and do not require the use of GSUs. AI Initial Brief at 71-72. Ex. AIW-46 at 20.

Initial Decision

The judge determined that, consistent with his finding that GSUs perform a transmission function, GSU costs already are allocated to transmission customers. He held, therefore, that GSUs should not be included as a cost for any of the ancillary services.

Discussion

As discussed above, in section III.A.2.c, our reexamination of GSU costs in KU persuaded us that the costs of a GSU

75/ See City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984), cert. denied, 467 U.S. 917 (1984) (utility need establish only that its proposed rate design is reasonable, not that it is superior to all alternatives); MCI Telecommunications Inc. v. FCC, 627 F.2d 322, 340 (D.C. Cir. 1980) (the standard of "just and reasonable" does not require that the rates be perfect); New England Power Company, Opinion No. 352-A, 54 FERC ¶ 61,055 at 61,198, aff'd sub nom. Town of Norwood, Mass. v. FERC, 962 F.2d 20 (D.C. Cir. 1992) (a proposed rate design need only be shown to be just and reasonable, not superior to all alternatives).

76/ The generation-based ancillary services referred to by trial staff are: (1) Reactive Supply and Voltage Control; (2) Regulation and Frequency Response Reserve Service; (3) Operating Reserve - Spinning Reserve Service; and (4) Operating Reserve - Supplemental Reserve Service.

transformer should be directly assigned to its related generating unit, not rolled into transmission rates. In KU, we stated that:

> GSUs also perform an important function in the provision of a new category of services we identified in Order No. 888, ancillary services (e.g., Operating Reserve, Regulation and Frequency Response Service, Reactive Supply and Voltage Control). Ancillary services supplied from generation resources cannot be provided without reliance upon GSUs, regardless of where power is coming from or going to.
>
> In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using these facilities. [85 FERC at 62,112].

Therefore, we find that it is appropriate to include the cost of GSUs in developing rates for all ancillary services that are supplied from generation sources. Accordingly, we reverse the judge's finding in the Initial Decision that GSUs should not be included as a cost for any of the ancillary services, and we instead adopt trial staff's proposal to include GSU costs in ancillary services rates.

5. Energy Imbalances

Order No. 888-A defines Energy Imbalance Service as follows:

> Energy Imbalance Service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to make up the difference . . . by adjusting its energy deliveries to eliminate the imbalance. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus, the Final Rule established an hourly energy deviation band of +/- 1.5 percent (with a minimum of 1 MW) for energy imbalance. [77/]

77/ FERC Stats. & Regs. ¶ 31,048 at 30,229. In Order No. 888-A, the Commission clarified the definition of Energy Imbalance Service provided in Order No. 888, FERC Stats. & Regs. ¶ 31,038 at 31,960-61.

a. Deadband

Positions of the Parties

AEP offered a deviation band (also known as a "deadband") of 1.5 percent, consistent with the figure we required in Order No. 888. 78/ AIW argued that the deadband of 1.5 percent is too small and discriminates against smaller systems. AI Initial Brief at 42, AI Reply Brief at 62.

Trial staff argued that AEP complied with the Commission requirements by establishing a deadband of +/- 1.5 percent. Trial Staff Initial Brief at 73-74.

Initial Decision

The judge rejected arguments made by AIW and ruled that AEP properly included a deadband of +/- 1.5 percent, as required by Order No. 888. 80 FERC at 65,085.

Exceptions

AIW filed exceptions, generally reiterating its arguments made before the judge. 79/ In opposing AIW's exceptions on this issue, trial staff argues that changing the size of the deadband would amount to changing a term and condition of the Order No. 888 *pro forma* tariff, which is beyond the scope of this proceeding. AEP and trial staff point out that Order No. 888-A, while keeping the deadband at +/- 1.5 percent, modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW to address the concerns raised by smaller systems such as AIW.

Discussion

We affirm the judge. In Order No. 888-A, we addressed the issue of the size of the deviation band in detail. There, we held that a bandwidth of 1.5 percent promotes good scheduling practices by transmission customers and that the implementation

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78/ When the energy imbalance is within the prescribed bandwidth, the energy may be returned in kind. When the energy imbalance is outside the bandwidth, specific rates are applicable as discussed below.

79/ AI Brief on Exceptions at 71-72; WVPA Brief on Exceptions at 23-24.

of scheduled transactions should not overly burden others. 80/ Also, as noted by AEP and trial staff, in Order No. 888-A we modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW. 81/ We therefore conclude, as did the judge, that AEP's proposals on bandwidth comply with the requirements of Order Nos. 888 and 888-A. Accordingly, we affirm the judge's finding on this issue for the reasons set forth in the Initial Decision.

b. Charges for Under-Scheduled Power

Positions of the Parties

AEP argued that a transmission customer should pay a charge of 100 mills/kWh for under-scheduled energy outside the deadband. 82/ Trial staff supported this charge stating that such a charge would act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load.

AIW argued that all under-scheduled energy should be returned in kind. However, AIW asserted that a 100 mills/kWh charge may be reasonable for under-scheduled energy which exceeds the 7.5 percent (i.e., 1.5 percent for the deviation band plus 6 percent for operating reserve services) the customer purchases from AEP or supplies itself.

Initial Decision

The judge found AIW's position that all under-scheduled power be returned in kind to be inconsistent with the Order No. 888 provision that requires a separately stated charge for such under-scheduled power. The judge also found that AEP's 100 mills/kWh charge was reasonable because such a charge accounts for the fact that the imbalances occur on an hourly basis. The judge ruled that AIW's interpretation that customers that buy operating reserves from AEP are entitled to a 7.5 percent deadband is not correct, and that Order No. 888 provides for several ways in which the customer may reduce or eliminate the need for energy imbalance service, such as dynamic scheduling.

80/ See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,232-33.

81/ Id.

82/ 100 mills/kWh was the rate utilities typically charged their customers for emergency power service, and in Detroit Edison Company, Opinion No. --, 88 FERC ¶ 61,--- (1999) (Detroit Edison), we recently found that energy imbalance service is similar to emergency power service.

Exceptions

AI argues that a 100 mills/kWh charge might be reasonable if the deadband is expanded to include operating reserves. However, AI contends that since the judge did not expand the deadband to include operating reserves, the charge should be no greater than AEP's out-of-pocket costs. AI and WVPA argue that the charge for energy outside the deadband is too high and not cost-justified. AI Brief on Exceptions at 72; and WVPA Brief on Exceptions at 14, 22-24.

Discussion

As we explained above, "Energy Imbalance Service" is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over a single hour. We did not intend it to be used as a substitute for operating reserves. See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,230. Furthermore, we find that a 100 mills/kWh charge for underscheduled energy outside the deadband is reasonable because such a charge will act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load. In addition, in Detroit Edison we recently found that energy imbalance service is similar to emergency power service, and that 100 mills/kWh is the rate utilities typically have charged their customers for emergency power service. Accordingly, we affirm the judge's finding on this issue.

6. **Losses**

a. Reserve Margin

Positions of the Parties

AEP proposed a 20 percent reserve margin in calculating costs associated with capacity required to make up for losses. AEP explained that: (1) losses are similar to firm load; (2) losses cannot be controlled and are not subject to curtailment; and (3) transmission customers do not have to buy loss service from AEP and instead are free to make alternative arrangements to supply losses. AEP Initial Brief at 43; Ex. A-28.

AIW disagreed with AEP's proposal and argued that a transmission customer is required to provide spinning and supplemental operating reserves for the full amount of its load and losses under AEP's tariff Schedules 5 and 6. Therefore, AIW asserted that an obligation to pay for a separate 20 percent reserve margin is essentially a double charge.

Initial Decision

The judge ruled that although the transmission customers have alternative ways of supplying losses, a 20 percent reserve margin for losses on top of spinning and supplemental operating reserves of 6 percent would amount to double counting of reserves. Therefore, the judge determined that a 14 percent reserve margin is appropriate in this case for calculating capacity costs for losses.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative. Notwithstanding the fact that there were no exceptions filed to the judge's determination that a 14 percent reserve margin is appropriate, we find no basis for AEP's contention that any reserve margin is cost-justified for loss service. First, AEP has sponsored no studies or quantitative evidence showing that a reserve margin of any amount is cost-justified for loss service, and there is no Commission precedent supporting such a charge. Second, in Order No. 888 we neither required customers to take such a service from their transmission providers or for transmission providers to provide such a service. There is no basis for AEP to assess a charge under its open access tariff for a service that is not even offered under that tariff. Finally, we disagree with AEP's claim that losses are similar to firm load. In fact, AEP's provision of loss services is discretionary both for AEP and its customers. Thus, we find no justification for AEP's imposition of a charge for reserves for loss service.

b. Transmission Loss Factor

Positions of the Parties

AEP proposed a transmission loss factor of 3.6 percent. AIW contended that AEP's loss factor is excessive arguing that: (1) AEP did not provide any support that losses from theoretical load flow and other studies represent actual system losses; and (2) losses on AEP's local area network and distribution system (facilities below 69 KV) should be excluded from this loss factor calculation because many of AEP's transmission customers provide losses on their own local area networks and distribution system. To rebut AIW's claim that it was improper for AEP to roll-in the local area networks and distribution losses, AEP argued that its charging of losses associated with all transmission facilities used to provide service is in accordance with Commission policy favoring rolled-in pricing. 83/ Trial staff did not contest AEP's loss factor.

Initial Decision

The judge determined that AEP's loss factor of 3.6 percent is reasonable. The judge rejected AIW's claim regarding local area network and distribution use stating that AIW did not present any evidence to prove its claim, nor did it offer any evidence showing what percentage should be assigned to that portion of the losses allegedly associated with the distribution function. He held that AIW did not provide any arguments to rebut AEP's reliance on Kentucky Power. Specifically, that case affirmed a prior Commission order 84/ approving an increase in the AEP loss factor from 2.0 percent to 3.6 percent. The Commission held in Appalachian II that:

> AEP's proposal is entirely consistent with the Commission's requirements for charging customers for transmission losses. . . . Customers' service is provided by and priced on the basis of the AEP integrated transmission system . . . . [85/]

Exceptions

AI filed exceptions in which it generally reiterates the same arguments made by AIW before the judge. AI Brief on Exceptions at 72-73.

Discussion

We affirm the judge's finding, adopting a loss factor of 3.6 percent, for the reasons set forth in the Initial Decision. However, we note that the AEP study includes all facilities including GSUs. Because we have ruled that GSUs should be assigned to production, we will require AEP to recalculate the transmission loss factor to exclude real power losses attributable to GSUs.

83/ AEP cited Kentucky & Ohio in support of its claim. AEP Initial Brief at 43. In Kentucky & Ohio, the Commission specifically approved the rolled-in method with respect to losses on the AEP System. 64 FERC at 61,923.

84/ Appalachian Power Company, et al., 63 FERC ¶ 61,165 (1993) (Appalachian II).

85/ Id. at 62,149.

The Commission orders:

(A) The Initial Decision issued in this proceeding on August 7, 1997 is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) AEP is hereby directed to submit a compliance filing within 60 days of the date of issuance of this order. However, if a request for rehearing is filed, AEP shall make its compliance filing within 30 days of the date the Commission disposes of the request for rehearing.

(C) Within 30 days of acceptance of the compliance filing, AEP shall make refunds, together with interest calculated pursuant to 18 C.F.R. § 35.19a (1999). Within 15 days of the date of payment of refunds, AEP shall file a report showing the computation of refunds and interest paid. A copy of the refund report shall also be sent to the affected state commissions.

By the Commission.

(S E A L)

David P Boergers
David P. Boergers,
Secretary.