COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF AN AMENDED COMPLIANCE PLAN FOR PURPOSES OF RECOVERING ADDITIONAL COSTS OF POLLUTION CONTROL FACILITIES AND TO AMEND ITS ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF	))))))	CASE NO. 2005-00068

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PUBLIC SERVICE COMMISSION

SUPPLEMENTAL RESPONSE OF
KENTUCKY POWER COMPANY
D/B/A
AMERICAN ELECTRIC POWER
TO
KIUC'S FIRST SET OF DATA REQUESTS
ITEMS 17 AND 18

Kentucky Power supplements it's Response to KIUC's First Set of Data Requests by providing the attached July 27, 1979 "Opinion and Order Approving Amendment of Interconnection Agreement With Modifications" of the Federal Energy Regulatory Commission. This FERC Order is in further response to Data Requests Items 17 and 18.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing was served via United States Postal Service, First Class Mail, postage prepaid, upon:

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on this the 4th day of May, 2005.

Bruce F. Clark

Bruce F. Clark

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 50

American Electric Power Service Corporation	))	Docket No. E-9408

OPINION AND ORDER APPROVING AMENDMENT OF INTERCONNECTION AGREEMENT WITH MODIFICATIONS

Issued: July 27, 1979

DC-A-5

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

America Electric Power Service Corporation) Docket No. E-9408

OPINION NO. 50

APPEARANCES

Cynthia M. Cohen, Rogers Doering and James Haugh for Ohio Power Company

Lance W. Schneier and Robert M. Minor for Ormet

Douglas B. Hughmanick, Robert J. White, Edward J. Grenier, Jr., and Robert Sproul, Jr. for Kaiser Aluminum and Chemical Corporation

Joel Shipman for West Virginia Public Service Commission

Larry Wallace and Theodore Sandak for Public Service Commission of Indiana

A. Jack Fitullo for Public Utilities Commission of Ohio

Lynn Hargis for the Staff of the Federal Energy Regulatory Commission

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Charles B. Curtis, Chairman;
Georgiana Sheldon, Matthew Holden, Jr.,
and George R. Hall.

OPINION NO. 50

OPINION AND ORDER APPROVING
AMENDMENT OF INTERCONNECTION
AGREEMENT WITH MODIFICATIONS

(Issued July 27, 1979)

This proceeding is before us on exceptions to an initial decision issued after hearings by a presiding administrative law judge. An oral argument, with the Commission sitting en banc, was held on June 20, 1979. The notice scheduling the argument included a draft opinion which had been prepared for the Commission's consideration by its Office of Opinions and Review. This procedure, which is innovative at least insofar as this Commission is concerned, was utilized primarily because of the complexity of the proceeding and the fact that the conclusions proposed differed substantially from those suggested by the law judge. The draft decision was made available to the parties in advance of the oral argument in order to better enable them to address their remarks to the matters considered to be an issue in the proceeding as well as to comment on the suggested resolution. It appeared at the argument that the release of the draft decision was well received and, we believe, its availability contributed to the presentation of more sharply focused argument. We will continue to utilize this procedure whenever, in our opinion, considerations of time and the circumstances of the particular proceeding warrant.

In general we find that we have not been persuaded by the discussion at the oral argument that the resolution recommended in the draft decision is substantially in error. To the contrary, we are more firmly convinced that the proposed determination is in the overall public interest at this time. Thus, while the present decision differs in few respects from the draft opinion, we believe it appropriate, in response to the positions taken by several of the state Commission intervenors, to emphasize again the *sui generis* nature of our determination herein, a determination which reflects and in large measure is predicated on the existing circumstances of capacity availability on AEP's integrated system. As recognized in several of the comments at the oral argument and as brought out subsequently, this decision involves a balancing of equities and an accommodation of diverse interests necessitated by present supply circumstances, rather than the application of the theoretically superior method. We would anticipate that when the present large intercompany disparity between supply and demand is reduced, an opportunity will be available for re-examination of the operation of the Interconnection Agreement.

* * *

This proceeding involves a proposal by the American Electric Power Service Corporation (AEP), filed April 29, 1975, to amend an Interconnection Agreement dated July 6, 1951, 1/ executed by the principal operating subsidiaries of the AEP system establishing the charges for sales of power and energy among the interconnected companies. The proposed amendment, which is referred to as Modification No. 3 (Mod. 3), was suspended for one day and then was permitted to go into effect subject to refund pending a determination of its lawfulness under Sections 205 and 206 of the Federal Power Act. 2/

1/ Filed as Ohio Power Company's F.E.R.C. Rate Schedule No. 23.

2/ This proceeding was commenced before the Federal Power Commission (FPC). By the joint regulation of October 1, 1977 (10 CFR 1000.1), it was transferred to the FERC. The term "Commission", when used in the context of action taken prior to October 1, 1977, refers to the FPC; when used otherwise, the reference is to the FERC.

The four principal operating companies of the AEP System and their electric service areas are (a) Appalachian Power (Appalachian), serving in western Virginia and in the southern part of West Virginia, (b) Indiana & Michigan Electric (I&M), serving in the northern and east central parts of Indiana and the southwestern corner of Michigan, (c) Kentucky Power (KPC), serving in eastern Kentucky, and (d) Ohio Power (OPC) serving an extensive area in Ohio. The AEP System also includes three generating companies, each organized as a wholly-owned subsidiary of one of the principal operating companies, which own and operate generating facilities. The generating subsidiaries sell at wholesale and deliver all of the power and energy they produce to their respective parent companies, pursuant to contracts filed with the Commission as rate schedules. The generating companies are (1) Ohio Electric Company (Ohio Electric), a wholly-owned subsidiary of OPC, which owns and operates the Gavin Plant, located in southern Ohio, consisting of two 1,300,000 kW coal-fired generating units which were placed in service in 1974 and 1975; (2) Indiana & Michigan Power Company, (Indiana & Michigan Power), a wholly-owned subsidiary of I&M, which owns and operates the Cook Plant, located on Lake Michigan near Bridgman, Michigan, consisting of two 1,100,000 kW nuclear generating units, the first of which was placed in service in 1975, and the second of which was placed in service in the summer of 1978; and (3) Kanawha Valley Power Company, a wholly-owned subsidiary of Appalachian, which since the 1930's has owned and operated under license two hydroelectric generating facilities, located on the Kanawha River in West Virginia, having a capability of 51,000 kW.

As indicated above, an initial decision was issued on February 23, 1978. that decision contains a review of the procedural history of the case, the provisions of both the 1951 Agreement and the changes occasioned by Mod. 3, and the positions of the parties.

Despite our desire to avoid repetition of material already set out in the initial decision, some brief description of Mod. 3 and of staff's proposed alternative is useful as an aid in comprehending the various issues in dispute. The principal effect of Mod. 3 is to increase the primary capacity equalization charge used in determining the amount of compensation for primary capacity surpluses and deficits among the parties to the Agreement. The previously used charge consisted of a uniform capacity rate of $1.00 per kilowatt per month and an annual fixed charge rate of 12% plus a weighted average fixed operating cost. Mod. 3 provides for the retention of the previously used weighted average fixed operating cost but would replace the $1.00 per kW per month capacity rate with a rate based on the more recent embedded capacity costs of the individual system members. 3/ It also includes a fixed monthly carrying charge factor of 1.46%, equivalent on an annual basis to a rate of 17.5%.

Another major change involves the elimination of a ceiling imposed on economy energy charges, whereby such charges were limited to not more that 125% of the out-of-pocket costs incurred by the member supplying such energy. This change maintains the basic formula set out of the 1951 Agreement, which is essentially a sharing between buyer and seller of the savings resulting from the transaction.

Three minor changes to the 1951 Agreement also are embodied in Mod. 3. These changes involved the elimination of all "secondary energy" and "secondary capacity" classifications, the elimination of a lag in the recovery of costs, and a change in the definition of "member primary capacity" to permit a member, with the concurrence of the other members, to purchase capacity from a "foreign" (i.e. any nonaffiliated) company and to include such capacity as primary capacity of the member.

The Commission staff presented testimony urging that the primary capacity equalization charge contained in Mod. 3 was too low. It recommended that the charge be based upon the costs of the most recent generating units installed by surplus members, rather than on the average or embedded costs of generating capacity of surplus members as provided in Mod. 3. Staff also opposed the "split-savings" method of pricing economy energy charges contained both in the 1951 Agreement and in Mod. 3. Finally, staff presented testimony opposing the return component of the proposed 17.5% annual carrying charge rate reflected in Mod. 3 and recommended the use of the actual embedded capital costs of each surplus member in calculating the capacity equalization charges.

In light of the detailed description contained in the February 1978 decision, we shall forego a further recounting of these elements except as necessary to support the findings and conclusions developed herein. The administrative law judge determined that the changes which would be made by Mod.3 in the primary capacity equalization charge and in the economy energy charge had not been proven to be just and reasonable. He likewise found that the even more substantial change (in terms of monetary effect) to the primary capacity

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3/ AEP's witness McNulty testified that the embedded capacity cost calculated for each member would be updated each year based on data available as of the end of the next preceding year (Tr. p. 148).

equalization charge proposed by two parties, Ormet Corporation and Kaiser Aluminum and Chemical Corporation, 4/ and the staff were unsupported by the record and also should be rejected. The law judge recommended adoption of the subsidiary changes proposed in Mod. 3 involving elimination of the "secondary energy" and "secondary capacity" classifications and of a lag in the recovery of costs. In all other respects he found that the rates and charges embodied in the 1951 Agreement as it existed prior to Mod. 3 were reasonable and recommended the refund of all amounts collected in excess of those levels. The decision makes clear that in reaching his conclusion the law judge was influenced by his determination that the changes proposed to the Interconnection Agreement were deficient in failing to accord adequate recognition to the investment in capacity made by each of the AEP operating subsidiaries.

The exceptions by the parties to the initial decision continue to reflect, in general, the positions previously taken by them in the proceeding. Thus, AEP persists in seeking approval of its proposed Mod. 3 without change; the Indiana and Michigan Municipal Distributors Association, the Michigan Public Service Commission and the Indiana Public Service Commission support the law judges's decision; the West Virginia Public Service Commission supports the law judge's recommendation to deny the increase in the primary capacity equalization charge but excepts to his finding on the definition of member primary capacity; the Public Service Commission of Kentucky objects to the law judge's recommendation that the Interconnection Agreement be recast to recognize each company's investment in generating capacity; and the Public Utilities Commission of Ohio and the staff believe that Mod. 3, while moving in the proper direction, does not go far enough and affirm their support of the further changes recommended by staff. The Ohio Commission has indicated that the charge established by Mod. 3 "insufficient though it may be, is the very least acceptable alternative." Staff, which had advocated the charging of its recommended higher rate as of the effective date of the Mod. 3 filing and that AEP "be required to submit a refund plan to provide for flowing through amounts ordered to be paid above the pool charges /currently in effect/ in the form of credits to the total costs of service of retail and wholesale customers who ultimately paid excessive amounts because of the unreasonable low pool rate," 5/ appears to have moderated its position on the matter of refunds. In its final filing staff raises the

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4/ Though active throughout the hearings, both Ormet and Kaiser apparently have discontinued their representation efforts and did not file exceptions to the initial decision.

5/ Brief on Exceptions, p. 37.

possibility of making the higher pool charges which would result from its recommendations effective only prospectively from the date of the Commission's decision, without disturbing the charges paid and received by the respective AEP companies under Mod. 3 during the period of the refund obligation. 6/

DISCUSSION

Witnesses were presented by AEP to support its claim that changed conditions required modification of the 1951 Agreement. The testimony indicated that the capacity equalization charge incorporated in the original Agreement was predicated on a cost of approximately $100 per kW of installed generating capacity and that this amount continued reasonably to reflect the average cost of installed capacity of the various member companies until approximately 1970. Beginning at about that time, AEP claims, two circumstances combined to warrant a change in the charges for capacity between deficit and surplus members. First, the cost of capacity additions installed by the AEP companies in the 1970's increased to levels substantially in excess of that reflected in the 1951 rate and, second, a number of generating additions planned by several of the AEP companies were cancelled or deferred for various reasons, including financing limitations, increasing constraints on the availability of sites for large generating facilities, the necessity for compliance with environmental control regulations and delays in obtaining requisite federal and state regulatory authorizations to construct new generating facilities. Because of the cancellations and deferrals of major generating capacity additions, AEP's witness explained, largely for reasons not wholly within the system's control, it became apparent that the desired rotation of surplus generating capacity among the different companies would not occur and that OPC, which had added a large amount of capacity at the Gavin Plant of Ohio Electric, its subsidiary, would remain a surplus company for a considerable period of time. Conversely, I&M would remain deficit in capacity until well into the 1980's despite the very substantial investment in new capacity represented by the Cook Plant.

The evidence confirms each of these assertions by AEP. The record shows that the average system cost of capacity increased markedly in the 1970's with the addition of the 2600 mW coal-fired Gavin Plant at a cost of

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6/ On February 21, 1979, the Virginia State Corporation Commission filed a request for late intervention in order to participate in the remaining stages of this proceeding. The request for limited intervention is granted.

$588 million and the 2200 mW nuclear fueled Cook Plant costing $990 million. Plans for the construction of a new coal-fired plant and a pumped storage hydroelectric plant by Appalachian were abandoned, as was the addition of two 1,300 mW coal-fired units scheduled for installation by I&M. In short, the evidence establishes the validity of AEP's claim that a change became necessary in the rates and charges levied under the Interconnection Agreement in that the then existing charges did not continue to reflect adequately a proper sharing of the benefits and burdens of the generating capacity available on the AEP system.

As indicated earlier, staff and the Ohio Commission do not agree with the proposition inherent in Mod. 3 which bases the capacity equalization charge on the average investment cost of the surplus members' generating units other than hydro. Although both acknowledged that Mod. 3 would help to overcome the inadequacy of the capacity rate included in the 1951 Agreement, they assert that the new charge is insufficient in that it fails to compensate those pool members with surplus capacity for the actual costs of building such capacity. Staff contends that the equalization charge should be based on the investment cost of the generating units actually used to supply the deficient capacity -- which it interprets as "usually a member's latest units" -- rather than on the average investment cost of all units of the surplus companies. Staff also argued that the associated fixed charges should be calculated on the costs of the units supplying the deficiencies. The Ohio Commission, which has as its main concern in this proceeding the revenues received by OPC as a surplus member of the system, supports staff's claim that the charge should be based on the surplus member's latest unit (or units) of capacity, and not on a system average or embedded cost.

Prior to our determination of this fundamental issue in dispute, it is necessary to address another matter raised in the initial decision and the subject of some exceptions, namely the status under the Agreement of the Gavin and

Cook Plants. The law judge concluded that the capacity represented by these plants was not includable as primary capacity of OPC and I&M, respectively, but instead should be treated as capacity made available by transactions with "foreign companies" under Article 7 of the Interconnection Agreement. While the question whether capacity owned by an affiliate of a member company comes within the Agreement's definition of "member primary capacity" 7/ is not entirely clear, we believe the weight of the evidence supports AEP's and the West Virginia Commission's claim that capacity available to members from generating subsidiaries is properly classified as primary capacity of such members.

None of the parties to the proceeding challenged such inclusion by AEP nor was any question raised to suggest that a redefinition of member primary capacity was necessary to include specifically the capacity of wholly-owned subsidiaries. The practice of the AEP companies is consistent with this conclusion as can be seen from the fact that Appalachian has had available all of the 51,000 kW of hydroelectric generating capacity owned by its wholly-owned subsidiary, Kanawaha Valley Power Company, and this capacity has been included as primary capacity of Appalachian from the inception of the Agreement in 1951. We are also influenced by the express definition of foreign company in the 1951 Agreement (Section 0.4) as encompassing "non-affiliated electric utility companies..." (including the Tennessee Valley Authority, which interconnects with Appalachian) in establishing the mode of treatment to be accorded the costs and benefits flowing from transactions with such companies. On the other hand, it does appear that where the framers of the original Agreement distinguished between "member primary capacity" and "member secondary capacity" (Sections 5.9 and 5.10), they were careful in the latter category to

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7/ Section 5.7 defines "member primary capacity" as "The more efficient steam and hydro capacity installed at the generating stations of the members normally expected to operate and carry load." (emphasis added) include not only the relatively less efficient capacity installed at generating stations of a particular member, but also such capacity at "... generating stations not owned by said Member but where the operation and production costs thereof are the responsibility of said Member." Thus, it appears that adequate specificity was included where the need was foreseen.

We perceive no statutory or other public interest consideration which mandates the use of criteria based on legal title or direct ownership of generating capacity (as opposed to ownership through the mechanism of wholly owned subsidiaries) where the reasons for the existing mode of ownership are known (at least for the Gavin and Cook Plants) and where the operation and sales are fully consistent with the purposes intended to be served by the Interconnection Agreement. The treatment of the Kanawha capacity as primary capacity over a course of more than twenty years without challenge upholds AEP's contention that Section 5.7 prescribes substantive, operating critera for eligibility as primary capacity, irrespective of whether the capacity is available to a member directly through ownership or indirectly through a wholly-owned subsidiary supplying all of its capacity or energy to its parent by contract.

We note that Mod. 3 would amend the definition of "member primary capacity" to make clear its inclusion of both (a) capacity installed at generating stations owned by the member and (b) capacity available to the member through interconnection arrangements with affiliated companies or foreign companies. We believe this modification is beneficial in eliminating the uncertainty inherent in the original definition. Insofar as foreign company purchases are concerned, this represents an improvement over the original treatment provided in Article 7. In addition to providing more clarity, the redefinition of member primary capacity set out in Mod. 3 would allow a deficit member to purchase capacity from a non-affilitated company and thereby decrease or eliminate its capacity deficit for pool purposes. To the extent that such purchases may aid in minimizing the long-term deficit capacity status of I&M and Appalachian, and foster enhanced competition, increased reliability and regional coordination, we believe the amendment serves a salutary purpose.

Section 5.7 of Mod. 3 vests the Operating Committee with the responsibility of determining whether additional capacity made available to a member as a result of an interconnection arrangement should be treated under Section 5.7(ii) /capacity available through interconnection with affiliated or foreign companies/ or Article 7 /transactions with foreign companies/. The law judge found that this redefinition would provide the operating Committee with "unwarranted discretion." Considering all of the changes to the existing Agreement which are to be affected by Mod. 3, it is our conclusion at this time that legitimate reasons may well exist for lodging such discretion in the Operating Committee. However, to assure that the authority is exercised consistent with purposes intended, AEP is directed to file appropriate guidelines for including such purchases as primary capacity of the member instead of as foreign purchases under the Agreement. The law judge's determination on these matters is reversed.

Staff questioned the fact that while capacity purchases from foreign companies are to be included in member primary capacity, capacity sales are not excluded. AEP's response was not fully definitive and a vagueness was left in the record on this matter. The draft opinion had proposed that sales of firm capacity be deducted from the aggregate capacity of a member in calculating that member's primary capacity. At the oral argument, however, AEP's counsel pointed out that this procedure would not take into account the reserves which must be maintained by the selling member to support the sale. He also noted that § 5.7 of the Interconnection Agreement already provides that such sales are added to the seller's load in determining the Member Load Ratio. Staff counsel appeared to concede the validity of this argument.

The problem arises from the fact that the amendment to Section 5.7 is not specific in its use of the term "capacity." It appears that staff's witness was concerned with the failure of the Agreement to treat sales of unit capacity and other non-firm capacity sales by one member to another, or by a member to a non-member utility. We agree that these forms of sales, if effected, should be deducted from the capacity available to the selling member as well as (as Mod. 3 provides) being added to the capacity of the purchasing member. The treatment of firm sales is proper under the Agreement and no further modification is necessary with regard thereto.

A question was raised in the initial decision regarding the status under the Agreement of the Cook Nuclear Generating Plant as part of I&M's primary capacity. Observing that the definition limits primary capacity to "steam generating plants and hydro," the law judge seemingly held that a revision of the definition would be a prerequisite to the inclusion of Cook capacity. Again, in dealing with production expenses, he concluded that the costs of nuclear generation would be excluded by the original Agreement.

We do not accept the law judge's interpretation that the Cook Nuclear Plant is not a "steam generating plant." The Cook units are pressured water reactor systems which utilize superheated water to produce steam which turns turbine-generators. While the source of the heat used to produce the steam differs from that in the more common fossil-fueled generating plant, we find no basis for distinction within the definition contained in the Interconnection Agreement to support a conclusion that the Cook Plant is not comprehended within the generic category of steam generating stations.

One other major change, beside that involving the capacity equalization charge, would be occasioned by Mod. 3. 8/ Under Section 6.6 of the 1951 Agreement, economy energy was priced on the "split-savings" method, i.e., the out-of-pocket incremental cost of the supplying member plus one-half of the difference between the supplier's incremental cost and the out-of-pocket decremental cost of the receiving member. However, the 1951 Agreement contained a limitation that the supplier could not receive more than 125% of his out-of-pocket costs. Mod. 3 would eliminate the ceiling so that economy energy would be priced wholly on a split-savings basis.

8/ We have referred earlier to the elimination of the "secondary energy" and "secondary capacity" classifications, and of a lag in the recovery of costs. These changes were approved in the initial decision and no exceptions were filed on these issues. These changes are confirmed.

Staff opposed the basic split-savings method for the pricing of economy energy. Staff argued that the economy energy rate should be set at the supplier's cost, determined after the transactions have taken place, and should be based prospectively on the costs of the units used in supplying the economy energy. Staff's witness testified that the filed economy energy charge is unreasonable in that (1) it may have a greater tendency than the superceded charge to prolong unit outages and may influence decisions to retire less efficient generating units, and (2) it is based on"simplified cost computation methods not commonly used by centrally dispatched power pools." 9/

Elimination of the 125% ceiling has the effect of permitting an equal sharing of the cost savings from an economy energy transaction between the supplier and the recipient. Conversely, the operation of the ceiling in the 1951 Agreement could have the effect, depending on the particular circumstances, of allocating a disproportionate share of realized cost savings to the recipient of economy energy.

Staff's witness did not defend the ceiling, nor did he support its deletion. Rather, he recommended an economy energy rate based solely on the supplier's cost. Although we appreciate the concerns prompting staff's recommendation, there is no evidence in the record that any such inappropriate actions or imprudence occurred during the 25 years of operation under the 1951 Agreement. Moreover, we have continued to monitor the operations under Mod. 3 since it was placed in effect provisionally in 1975 and find no basis for concern in the areas raised by staff. In sum, we find that the split-savings provision in Mod. 3 is one of a variety of reasonable methods for allocating the savings derived from economy energy transactions and has been accepted in prior Commission decision. 10/ The amendment to the prior provision to eliminate the 125% ceiling is accepted and the provision in Mod. 3 is approved.

9/ Tr. p. 314.

10/ E.g., Gainesville Utilities Dept. v. Florida Power Corp., 40 FPC 1227, 1235, 1245 (1968); Public Service Company of Indiana, et al., 47 FPC 1396, 1405, 1410 (1972). See 1970 National Power Survey, Part I, pages I-1/-8 and 9.

We return now to the basic issue in this proceeding, that of the method to be used in calculating the primary capacity equalization charge. We have referred earlier to the differences between staff's proposed charging method and that contained in Mod. 3. Full details are provided in the initial decision. It is our conclusion, after study of the record and consideration of the arguments presented by the parties, that the charges levied under the 1951 Agreement do not reflect the increased costs of recent capacity additions and are therefore outdated, unfair and unreasonable, and that a change is required to reflect the present day benefits and burdens relating to the generating capacity installed by the AEP member companies. It is our further conclusion that staff's proposal of basing the charge on the investment cost of the units supplying the needed capacity to the deficit members is the superior method in theory in that it would assure that the member with surplus capacity was more completely compensated for the actual ownership costs incurred in making surplus capacity available to capacity deficient members. Moreover, the economic decisions of the various member companies related to power sources (new capacity additions, purchasing from pool members and purchases from foreign companies) would be more soundly based and the design of the rates charged by the companies, retail as well as wholesale, would be based on realistic costs -- as would the economic decisions of the companies' retail customers relating to their energy supplies. We also are aware of other desirable (although less certain) advantages of staff's proposal, including the timely installation of new generating units, the encouragement of competition among pool members and neighboring utilities, the promotion of regional coordination and, since the charges would be based on marginal cost pricing principles, the fostering of energy conservation at the retail level.

Nevertheless, despite our acknowledgement that staff's capacity equalization method has advantages over AEP's Mod. 3 proposal, it is our determination that its recommendation should not be adopted in this case. Instead, the Mod. 3 method for calculating the primary capacity equalization charge will be approved. However, as discussed hereafter, we do not accept the justification provided for the Monthly Carrying Charge Factor and therefore amend the factor provided in Mod. 3.

Our decision to allow the capacity equalization charge based on the average investment costs of the surplus members rests entirely on the circumstances present in this case, namely (1) the relative distribution of capacity surplus and deficiencies among the AEP member companies; (2) the fact that the existing status has remained constant since 1968 and is expected to persist well into the 1980's; (3) recognition of the disproportionate investment in capacity made by I&M vis-a-vis the other members and the heavy burden of that investment on I&M's ratepayers -- a burden which would be increased under staff's proposal -- and (4) the fact that, in the final analysis, the issue involves a matter of degree since even staff and the Ohio Commission admit that the Mod. 3 charge is an improvement over that contained in the original Agreement.

We accept for present purposes AEP's assertion that the systems of the four member companies participating in the Interconnection Agreement are planned and operated as a single, integrated utility system with the result that new generating and bulk transmission facilities are planned on an overall AEP system basis with due consideration to the requirements of the individual members. We likewise are aware, as pointed out earlier, that a number of planned additions of new generating capacity have been cancelled or deferred. These additions would have eliminated, or at least significantly improved, the deficit capacity status of I&M and Appalachian and, we believe, would have provided for a more reasonable rotation of excess capacity among the member companies than exists at this time. While AEP is endeavoring to construct new capacity to meet its anticipated loads in the various service territories, it is obvious that no major change in the existing pattern of supply will occur for a number of years.

Although I&M made a heavy investment in its Cook Nuclear Plant -- $990 million by the time of the second unit's activation in 1978-- it realized only 2200 mW of capacity, or an investment cost of $450 per kW. Construction on the Gavin fossil fired plant, on the other hand, resulted in the addition of 2600 mW of capacity at a total cost of $588 million, or only $226 per kW. While hindsight may indicate that I&M would have been better served from a capacity cost standpoint by the construction of a non-nuclear generating plant, there is no suggestion that the decision to undertake this plant was in any way imprudent. We note also that for 1976 and 1977 the overall cost per kWh of the energy produced by the Cook Plant was relatively low. Although I&M, as a deficit member, does not receive payments for capacity under the Agreement, it and its customers have the direct benefits associated with the low fuel costs of the Cook Plant energy. It must also be recognized that the Cook Plant is situated on Lake Michigan at the northwestern point of the entire AEP companies' service area, near I&M's principal load centers and removed from access to the coal reserves and coal transportation facilities along the Ohio River. In essence, we find no reason to conclude, under these circumstances, that the primary capacity equalization charge is defective in failing to reflect the investment in capacity made by the deficient members.

While affirming the use of average embedded costs in this case, we emphasize that our determination is predicated on the make-up of the AEP system as it now exists. The decision on this issue should not be considered as precedential in any future consideration by the Commission of this Agreement or of other interconnection arrangements.

In addition to basing the capacity equalization charge on the average installed cost per kW of the surplus member, Mod. 3 specifies a "Monthly Carrying Charge Factor", used in calculating the payments for capacity, of 0.0146, or 17.5% on an annual basis. Capital costs are the largest single component of the carrying charge and have been included on the basis of an overall cost of money (rate of return) of 11.50%. 11/ Staff's witness testified that if the investment portion of the equalization charge is based on the costs of the latest units, the appropriate capital costs should be then associated with the latest units. Staff's cost of capital evidence, however, was entirely on an embedded cost basis. While it made no attempt to calculate a rate of return on the capital cost of the latest units, it recommended that AEP be ordered to develop such a rate of return for each member.

We have decided, in our prior discussion, not to adopt staff's recommended "newest unit" theory for determining the capacity equalization charge. This being so, there is no merit to the suggestion for basing the rate of return on the associated capital costs of the latest units.

In the event the Commission decided against the use of the costs of capital associated with latest units, staff proposed separate rates of return for the four member companies based in their embedded costs and respective capitalization as of December 31, 1974. 12/ The overall returns ranged from 8.71% for Appalachian (12.75% on equity) to 9.47% for I&M (13.00% on equity). 13/ AEP recommended the use of a single, system-wide

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11/ Exh. P-8

12/ Exh. S-5, p.1.

13/ Staff recommended 9.29% overall for OPC (13% on equity) and 8.78% for KPC (11.5% on equity).

capital structure and an overall return of 11.18% to 11.51%. The company requested a rate of 9.0% to 9.5% on debt, 11.0% to 11.5% on preferred stock, and 15% on equity.

Without unnecessarily prolonging this discussion, and considering the purposes served by the Carrying Charge Factor, we accept as reasonable the unified capital structure recommended by AEP in the calculation of the return allowance, i.e., 57% long-term debt, 10% preferred stock, and 33% common equity. 14/ However, we will not accept AEP's incremental cost rates for debt and preferred stock. In line with the embedded cost approach being followed in this case, we believe that the costs of senior capital should also be reflected on an embedded cost basis and should additionally take into account the consolidated operations of the four Member Companies. The testimony of AEP witness Barber states that the weighted embedded costs of long-term debt and preferred stock issued by the four Member Companies were approximately 7.0% and 7.9%, respectively, at June 30, 1975. 15/ It is evident, however, that the 7.0% cost of debt does not reflect the debt of the generating subsidiaries as we believe it should. 16/

On the other hand, staff's Exhibit S-5 does present the capital structures and cost rates of the four Member Companies on a consolidated basis as of December 31, 1974 17/. Employing the data in this exhibit, we can derive an embedded cost of debt of 7.75% and embedded cost of preferred stock of 7.41%. The preferred stock rate, however, does not include a 14% preferred stock issue in 1975 that is taken into account in AEP's calculations. 18/ Consequently, we will use the 7.9%

14/ Tr., p. 269.

15/ Tr., p. 270.

16/ Exh. P-11, p. 2 of 2.

17/ Tr., p. 439.

18/ Exh. P-12.

preferred stock rate as the latest record evidence available along with our derived 7.75% cost of debt.

The testimony of the parties on the appropriate allowance for equity capital is of limited usefulness. AEP's defense of its request for a 15% return on common equity is exceedingly general and, consequently, not very persuasive, while staff's recommendation was based on separate rates of return for the four Member Companies, whereas we have opted for a single rate of return in this case. Nevertheless, based on statistical data presented in staff's Exhibits S-5 and S-6 and AEP exhibit P-14, and in consideration of equity returns recently allowed by this Commission, we find that a return on common equity of 12.75% is just and reasonable. The application of these cost rates to the above mentioned capital structure results in an overall rate of return of 9.42%. The inclusion of this cost of capital component, together with an adjusted component for Federal income taxes, results in annual and monthly carrying charge factors of 16.49% and 1.37%, respectively.

The Commission further finds:

(1) Ohio Power Company, Indiana & Michigan Electric Company, Appalachian Power Company and Kentucky Power Company are each a public utility as defined in the Federal Power Act and the sales by them of electric energy pursuant to the Interconnection Agreement dated July 6, 1951, are sales of electric energy at wholesale in interstate commerce subject to the jurisdiction of the Commission.

(2) The amendment to the Interconnection Agreement proposed by Modification No. 3 to increase the primary capacity equalization charge is just and reasonable under the existing circumstances and should be approved, except that the monthly carrying charge factor should not exceed 1.37%.

(3) The changes in the Interconnection Agreement proposed by Modification No. 3 for the purpose of eliminating the system secondary capacity and secondary energy classifications, and for the elimination of lag in the recovery of costs, are just and reasonable and should be approved.

(4) Ohio Power Company, through its agent, American Electric Power Sevice Company, should be required to file appropriate guidelines applicable to the exercise by the Operating Committee of its discretion in determining when a purchase by a member of capacity from a non-affilated company shall be included as "member primary capacity" under Section 5.7(ii) of the Interconnection Agreement.

(5) Section 5.7 of the Interconnection Agreement should be amended to exclude sales of unit capacity and other sales of non-firm capacity from member primary capacity.

The Commission orders:

(A) Modification No. 3 to the Interconnection Agreement dated July 6, 1951, filed as Ohio Power Company's F.E.R.C. Rate Schedule No. 23, is approved subject to the following conditions:

(1) Section 6.212 of the Agreement shall be changed to reflect a monthly carrying charge factor of 0.0137.

(2) Guidelines shall be submitted for the Commission's approval applicable to the Operating Committee's exercise of its discretion in determining when a purchase by a member of capacity from a non-affiliated company will be included as member primary capacity under Section 5.7(ii) of the Agreement.

(3) Section 5.7 of the Interconnection Agreement should be amended to assure exclusion of sales of unit capacity and other sales of non-firm capacity from member primary capacity.

(B) The filings required by Ordering Paragraph (A) shall be submitted within 30 days of the date of issuance of this Opinion.

(C) Ohio Power Company shall file an annual statement of the member weighted average investment cost as provided in Section 6.211 of the Agreement, including the basis for the amounts shown therein.

(D) Within 60 days from the date of issuance of this Opinion, Ohio Power Company shall provide a statement reflecting appropriate credits for all sales of energy under Modification No. 3 due to the required modification in the monthly carrying charge factor.

(E) Exceptions not granted are denied.

(F) The Initial Decision is affirmed to the extent consistent with this Opinion and Order.

By the Commission. Commissioner Holden, concurring, filed a separate statement appended hereto.

(S E A L)

Kenneth F. Plumb,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power
Service Corporation) Docket No. E-9408

HOLDEN, Commissioner, concurring:

(Issued July 27, 1979)

I withhold further objection to, and concur in the issuance of, the order of the Commission in this docket. The present order is a pragmatic solution and the case is of vintage quality, having been filed more than four years past and having been decided by the Administrative Law Judge seventeen months ago. Hence, no further delay is warranted.

However, I do believe it is a matter that we shall have to revisit. It is fundamentally unsatisfactory to ignore obvious fact and to rely for the long term upon the fiction of "separate" companies. Yet such reliance is clearly present in the manner in which the responsibility of one company to its partners within an interconnection agreement is described.

> "A deficit pool member by definition has failed to install sufficient generating capacity to meet its load and its proportionate share of the pool's installed reserve. To meet its reserve responsibilities and to equalize reserve obligations, the deficit member must purchase capacity from pool members whose installed capacity exceeds their loads and proportionate reserve requirements, and pay a reasonable and just rate for such capacity. This obligation to purchase and pay for capacity cannot be excused because installed capacity costs have escalated for all members. By reason of its deficit status, the deficit member has avoided the costs of installing adequate capacity and must equalize its reserve obligation by purchasing capacity installed by other pool members." 1/

That statement describes the purest concept of a power pool, in which independent companies make commitments to each other. When this is in effect, the management of each company is responsible for the interests of its separate investors. And, when this in effect, the certificate and/or rate regulators are

1/ American Electric Power Brief on Exceptions, pp. 28-29.

ultimately responsible for, and have capacity to effectuate, the interests of their several jurisdictional publics.

Pooling necessarily inhibits individual company discretion, but is independently accepted on the basis of perceived advantage. The situation is quite different on the American Electric Power System. I do not have to conclude that the difference is bad. But it should be recognized realistically, as it is in the statement of the Chairman of the Indiana Public Service Commission. At Oral Argument, Chairman Wallace stated:

> "We know what the responsibility of the state regulatory agency*with the dichotomy between the Federal and state roles. We are responsible for the retail rates. We are supposed to be the replacement for competition at the retail level, just as you are the substitute for competition at the wholesale level and we are supposed to allow rates that will only earn a reasonable return on the plant reasonably necessary and used for producing the electricity for retail customers. That as we all know sounds simple, but it is not very simple to implement. It is not simple or easy to implement under any circumstances but it is virtually impossible in some circumstances. The American Electric Power system to a certain extent is probably totally unregulated. I have never said that I felt that a state regulator, as a state regulator we can give even these traditional consents**of regulation, really have a handle on regulation of retail rates for this company if for no other reason than the operating companies in Indiana and six other states in which the company operates, those decisions are not made by the operating companies, the investment decisions are not made, and in the sense that the state regulatory commission can then effectively regulate them." 2/

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* Some word such as "agency" or "commission" apparently was omitted.

** Apparently transcription error. Was the word "constraints"?

2/ Oral Argument held at Washington, D.C., June 20, 1979, re American Electric Power Service Corporation, Docket No. E-9408, p. 675 and 676.

The same concept is present, in the filings by Michigan Public Service Commission and Indiana and Michigan Distributions Association.

In my view, the same concept is also implicit in the argument of the Ohio PUC against the Staff approach to costing. Ohio PUC notes the length of time that Ohio ratepayers have been involved in the charges of a surplus company, and anticipates the time in which the shuttle will be reversed and Ohio ratepayers will be in the deficit position. 3/

The shuttle effect is the result of the manner of planning and deciding the future of the American Electric Power system, as well as of changes in the real world (i.e. actual vs. projected load growth, financial exigencies, etc.) Thus, it is central management that decides which state's ratepayers will finance new construction on its system. (This is not to conclude that the American Electric Power system is in some manner imprudent, but merely to note that AEP is essentially the independent variable in a dynamic process and that the state regulatory process is indeed the dependent variable.)

If investment decisions are established by central management, then it can be argued possibly, that investment is the right criterion fairly to apportion charges.

Whether the investment basis, rather than the kilowatt capacity basis, for allocation is the right alternative, I do not now judge. Nor do I even have a provisional view that it would be superior. I do believe the dollars versus kilowatts choice deserves systematic comparison and a determination.

I do not preclude the possibility that even with a fuller record, the Commission should ultimately come to the same decision as is embodied in the present order. It is not necessary to attempt to resolve that question here. The record available to the Commission does not allow that determination.

All that is necessary is to observe that the Commission should probably review the interconnection agreement when there

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3/ Response of Ohio PUC re Docket No. E-9408, dated March 8, 1979, p. 2.

is a reasonable basis to believe that a superior practical alternative might, in fact, be developed. Whether this should involve a rate case under Section 205, a proceeding under 206, some form of broader examination under a Federal-State joint board format, collaboration with the NARUC, or some form of proceeding in which the relevant authorities of the Secretary of Energy to adopt an intervenor status might be utilized is a matter to be examined at some more appropriate time.

Matthew Holden, Jr.

Matthew Holden, Jr.
Commissioner