Modification No. 2

to

Interconnection Agreement

Dated May 14, 1963

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

Dated as of:
May 1, 1982

THIS AGREEMENT, made and entered into as of this 1st day of May 1981 by and between Kentucky Power Company (hereafter Kentucky Company) a Kentucky corporation and East Kentucky Power Cooperative, Inc. (hereafter East Kentucky), also a Kentucky corporation.

W I T N E S S E T H:

WHEREAS, Kentucky Company and East Kentucky entered into an Agreement dated, May 14, 1963, which Agreement was modified and supplemented thereafter (said Agreement as so modified and supplemented, being herein called the 1963 Agreement); and

WHEREAS, the parties desire that the 1963 Agreement be further modified as hereinafter set forth;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the parties agree as follows:

Section 1. Section 3.03 of Article 3 of the 1963 Agreement is hereby modified to read as follows:

"The following service schedules are agreed to and hereby made a part of this agreement:

Service Schedule A - Concurrent Exchange Service
Service Schedule B - Emergency Service
Service Schedule C - Coordination of Scheduled Maintenance of Generating Facilities
Service Schedule D - Interchange Power
Service Schedule E - Short Term Power
Service Schedule F - Energy Transfer
Service Schedule G - Limited Term Power
Service Schedule H - Fuel Conservation Energy"

Service Schedule H which is attached hereto as Appendix V, is hereby made a part of the 1963 Agreement.

Section 2. Article 7 of the 1963 Agreement is hereby modified to read as follows:

"ARTICLE 7
BILLING AND PAYMENT

7.01 Unless otherwise agreed upon, the calendar month shall be the standard period for all settlements under this Agreement. As soon as practicable after the end of each billing period, the parties shall cause to be prepared a statement showing the transactions during such period in such detail as may be needed for settlements under this Agreement.

7.02 All bills under this Agreement shall be rendered as soon as practicable in the month following the calendar month in which they were incurred and shall be due and payable, unless otherwise agreed upon, when rendered and payment of such bills shall be made by electronic transfer or such other means as shall cause such payment to be available for the use of the payee on or before the 12th day of the month in which the bill is rendered or five (5) business days after receipt of the bill, whichever is later. Interest on unpaid amounts shall accrue daily at the then current prime interest rate per annum of Citibank, plus 2% per annum, from the due date of such unpaid amount and until the date paid. Other than as required by law or regulatory action, bill adjustments must be made within six (6) months of the rendition of the initial bill."

Section 3. Service Schedule B - Emergency Service which has been agreed to and made a part of the 1963 Agreement is hereby cancelled and a new Service Schedule B - Emergency Service, attached hereto as Appendix I, is substituted therefor.

Section 4. Service Schedule D - Interchange Power which has been agreed to and made a part of the 1963 Agreement is hereby cancelled and a new Service Schedule D - Interchange Power, attached hereto as Appendix II, is substituted therefor.

Section 5. Service Schedule E - Short Term Power which has been agreed to and made a part of the 1963 Agreement is hereby cancelled and a new Service Schedule E - Short Term Power, attached hereto as Appendix III, is substituted therefor.

Section 6. Service Schedule G - Limited Term Power which has been agreed to and made a part of the 1963 Agreement is hereby cancelled and a new Service Schedule G - Limited Term Power, attached hereto as Appendix IV, is substituted therefor.

Section 7. This Modification No. 2 shall be effective from the date first above written to the expiration date of the 1963 Agreement.

Section 8. Except as hereinabove modified and amended, all the terms and conditions of the 1963 Agreement shall remain in full force and effect.

Section 9. This Modification No. 2 shall inure to the benefit of and be binding upon the successors and assigns of the respective parties hereto.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed by their duly authorized officers.

KENTUCKY POWER COMPANY

By Frank N. Bri

EAST KENTUCKY POWER COOPERATIVE, INC.

Donald R. Norris

By Donald R Norris

President and General Manager

SERVICE SCHEDULE B
EMERGENCY SERVICE

Under Agreement dated May 14, 1963

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

SECTION 1 - SERVICES TO BE RENDERED

1.1 In the event of breakdown or other emergency on the system of either party, involving either sources of power or transmission facilities, or both and which impairs or jeopardizes its ability to meet the loads of its system, the other party shall upon request deliver during a period of not exceeding 48 consecutive hours electric power and associated energy ("Emergency Power" and "Emergency Energy") in amounts up to 50,000 kilowatt-hours per hour and such additional amounts as in its sole judgment can be delivered without imposing any burden on its system's operations and without undue interference with service to its customers. A party may, upon request, deliver energy hereunder in the event of an emergency jeopardizing the ability of a system interconnected with the system of the requesting party to meet its loads. Every request hereunder shall identify the emergency that gave rise to it.

1.2 No party shall be obligated to deliver energy hereunder during the first 48 hours following a prior emergency during which it is delivering electric energy under another mutual emergency interchange agreement or at any time that delivery of such energy will impair its own system's ability to meet its loads.

SECTION 2 - COMPENSATION

2.1 When Kentucky Company is the supplying party-

2.11 Electric energy delivered under Section 1 above that is generated by the supplying party's system shall be settled for, at the option of the party supplying it, either by the return of equivalent energy upon request of such party or by payment of the greater of 110% of the out-of-pocket cost (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of supplying such energy or 3 cents per kilowatthour thereof; plus

2.12 Electric energy delivered under Section 1 above that is purchased by the supplying party's system from another interconnected system shall be settled for by a demand charge of 2 mills per kilowatthour of such purchased energy and an energy charge of 100% of the amount paid therefor by the supplying party plus one mill per kilowatthour of such purchased energy plus any transmission losses and taxes incurred.

When East Kentucky is the supplying party:-

2.13 Electric energy delivered under Section 1 above that is generated by the supplying party's system shall be settled for, at the option of the party supplying it, either by the return of equivalent energy upon request of such party or by payment of the greater of 110% of the out-of-pocket cost (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of supplying such energy or 3 cents per kilowatthour thereof; plus

2.14 Electric energy delivered under Section 1 above that is purchased by the Supplying party's system from another interconnected system shall be settled for by an energy charge of 100% of the amount paid therefor by the Supplying party plus 1.5 mills per kilowatthour of such purchased energy plus any transmission losses and taxes incurred.

2.2 If the option under subsection 2.11 or 2.13 is exercised of returning electric energy then it shall be returned at times when the load conditions of the party receiving it are equivalent to the load conditions of such party at the time the energy for which it is returned was delivered or, if such party elects to have equivalent energy returned under different conditions, it shall be returned in such amounts, to be agreed upon by the Operating Committee, as will compensate for the difference in conditions.

SERVICE SCHEDULE D
INTERCHANGE POWER

Under Agreement dated May 14, 1963

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

SECTION 1 - - SERVICES TO BE RENDERED

Economy Energy

1.1 Either party may arrange to purchase from the other party, electric energy ("Economy Energy") whenever it is possible to effect a saving thereby and, in the sole judgement of the party requested to supply the same, such energy is available. Economy Energy may also be arranged to be obtained from or delivered to systems interconnected with the parties, but not a party to this Agreement. Prior to each delivery of Economy Energy, the amount and time of delivery and the charge therefor shall be determined by the parties.

Non-Displacement Energy

1.2 It is further recognized that from time to time, occasions will arise when the effecting of transactions as provided under subsection 1.1 next above will be impracticable but that at the same time one of the parties may have electric energy (herein called "Non-Displacement Energy") which it is willing to make available from surplus capacity either on its own system or from sources outside its own system or both, that can be utilized advantageously, for short intervals, by the other party. It shall be the responsibility of the party desiring Non-Displacement Energy to initiate the receipt and delivery of such energy. The party desiring receipt of Non-Displacement Energy shall notify the other party of the extent to which it desires to use such energy, and whenever in its sole judgment such other party determines that it has Non-Displacement Energy available, schedules providing the periods and extent of use shall be mutually agreed upon. Neither party shall be obligated to make any Non-Displacement Energy available to the other.

SECTION 2 - COMPENSATION

Economy Energy

2.1 The charge for Economy Energy purchased by either party from the other party shall be based on the principle that the party purchasing it shall pay the out-of-pocket cost (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of the party supplying such energy and that the resulting savings to the receiving party shall be equally shared by the supplying and receiving parties.

2.2 When Economy Energy is obtained from or delivered to other systems interconnected with the parties, but not signatories to this Agreement, payments shall be based on the out-of-pocket cost of the supplying party or system providing the energy and an allocation of the gross savings which are defined as the difference between (1) what the out-of-pocket costs of the receiving party or system would have been to generate such energy, and (2) the out-of-pocket costs of the supplying party or system providing the energy. Such allocation shall be made as provided in subsections 2.21 and 2.22 hereinbelow:

> 2.21 Each party or system participating in the transactions other than the supplying and receiving parties or systems, shall be paid (a) its cost of purchasing the energy supplied, plus (b) its cost of additional transmission losses incurred, plus (c) fifteen percent of the gross savings remaining after deducting all such payments for transmission losses.
>
> 2.22 The supplying party or system shall be paid its out-of-pocket cost of providing the energy, plus one-half of the gross savings remaining after deducting all (b) and (c) payments made under subsection 2.21. The receiving party or system shall be entitled to the other one-half of the gross savings remaining after deducting all (b) and (c) payments made under subsection 2.21.

Non-Displacement Energy

2.31 Non-Displacement Energy delivered hereunder that is generated by the supplying party's system shall be settled for either by the return of equivalent energy or, at the option of the party that supplied such energy, by payment of the out-of-pocket cost (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of the supplying party in generating such energy plus ten percent of such cost. If equivalent energy is returned, it shall be returned at times when the load conditions of the party receiving it are equivalent to the load conditions of such party at the time the energy for which it is returned was delivered or, if such party elects to have equivalent energy returned under different conditions, it shall be returned in such amounts, to be agreed upon by the Operating Committee, as will compensate for the difference in conditions.

2.32 Non-Displacement Energy delivered hereunder that is purchased by the supplying party's system from another interconnected system shall be settled for by 100% of the amount paid therefor by the supplying party, plus one mill per kilowatthour of such purchased energy, plus any transmission losses and taxes incurred by the supplying party.

SERVICE SCHEDULE E
SHORT TERM POWER

Under Agreement dated May 14, 1963

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

SECTION 1 - SERVICES TO BE RENDERED

1.1 Either party may arrange to reserve from the other party, (a) electric power ("Weekly Short Term Power") for periods of one or more weeks or (b) electric power ("Daily Short Term Power") for periods of one or more days whenever, the party requested to reserve the same, is willing to make such power available. As used herein the term "week" shall mean any seven consecutive days, and the term "day" shall mean a twenty-four hour period commencing at 12 o'clock midnight and ending at the next following 12 o'clock midnight.

1.11 Prior to each reservation of Weekly or Daily Short Term Power, the number of kilowatts to be reserved, the period of the reservation, and the source of such power if the supplying party is in turn reserving such power from another interconnected system ("Third Party"), shall be determined by the parties. Such determination shall be confirmed in writing at the request of either party. If during such period conditions arise that could not have been reasonably foreseen at the time of the reservation and cause the reservation to be burdensome to the supplying party or its System, such party may by oral notice to the reserving party, such oral notice to be later confirmed in writing if requested by either party, reduce the number of kilowatts reserved by such amount and for such time as it shall specify in such notice, but kilowatts reserved hereunder that the supplying party is in turn reserving from another system may be reduced only to the extent they are reduced by such other system.

1.12 During each period that Weekly or Daily Short Term Power has been reserved, the party that has agreed to supply such power shall upon call by the reserving party deliver associated electric energy (" Weekly or Daily Short Term Energy") to the reserving party at a rate during each hour of up to and including the number of kilowatts reserved.

SECTION 2 - COMPENSATION

2.1 The reserving party of Weekly or Daily Short Term Power shall pay the supplying party Demand Charges for such Short Term Power at the following rates:

2.11 Weekly Short Term Power

2.111 When Kentucky Company is the supplying party:- at the rate of $1.25 per kilowatt reserved per such week.

2.112 When East Kentucky is the supplying party:- at the rate of $1.05 per kilowatt reserved per such week.

2.113 In the event the amount of Weekly Short Term Power taken is reduced upon request of the supplying party, the demand charge for each day (other than Sunday) during which any reduction is in effect shall be reduced by one-sixth (1/6) of the aforesaid supplying party's weekly demand rate per kilowatt of reduction.

2.12 Daily Short Term Power

2.121 For any day that Daily Short Term Power is reserved by either party, the daily demand rate shall be equal to the rate of one-fifth (1/5) of the supplying party's Weekly Short Term Power demand rate per kilowatt per day reserved.

2.122 In the event the amount of Daily Short Term Power taken is reduced upon request of the supplying party, the demand charge for each day, during which any reduction is in effect shall be reduced by one-fifth (1/5) of the above weekly demand rate per kilowatt of reduction.

2.13 Third Party Weekly Short Term Power

2.131 For any week that Weekly Short Term Power is reserved by either party from a Third Party at the rate of $0.24 per kilowatt reserved per week plus the demand charge paid therefor by the supplying party to the Third Party.

2.132 In the event the amount of Weekly Third Party Short Term Power taken is reduced upon the request of the Third Party, the demand charge for each day (other than Sunday) during which any reduction is in effect shall be reduced by one-sixth (1/6) of the total weekly charge in <u>subsection 2.131</u> above per kilowatt of the reduction.

2.14 <u>Third Party Daily Short Term Power</u>

2.141 For any day that Short Term Power is reserved by either party from a Third Party at the rate of $0.048 per kilowatt reserved per day plus the demand charge paid therefor by the supplying party to the Third Party.

2.2 The reserving party shall pay the supplying party Energy Charges at the following rates:

2.21 For all Short Term Energy delivered pursuant to subsection 1.12 above;

(a) for each kilowatthour that is generated by the supplying party's system 110% of the out-of-pocket costs (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of supplying Short Term Energy called for during such period; plus

(b) for each kilowatthour purchased by the supplying party from a third party to supply the Short Term Energy called for during such period, 100% of the amount of the energy charge paid therefor by the supplying party plus 1 mill plus any transmission losses, taxes and other expenses incurred that would not have been incurred if such purchase had not been made.

SERVICE SCHEDULE G
LIMITED TERM POWER

Under Agreement dated May 14, 1982

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

SECTION 1 - SERVICES TO BE RENDERED

1.1 Either party may arrange to reserve from the other party, for periods of not less than one or more than 12 months, such electric power ("Limited Term Power") whenever, in the sole judgment of the party requested to reserve the same, such power is available.

1.11 Prior to each reservation of Limited Term Power, the number of kilowatts to be reserved, the period of the reservation, and the source of the power if the supplying party is in turn reserving them from another interconnected system ("Third Party") shall be determined by the parties. Such determination shall be confirmed in writing.

1.12 During each period that Limited Term Power has been reserved, the party that has agreed to supply such power shall upon call deliver electric energy ("Limited Term Energy") up to and including the number of kilowatts then reserved to the reserving party, except when such deliveries would in the judgment of the supplying party have to be interrupted or reduced to preserve the integrity of, or to prevent or limit any instability on its system.

SECTION 2 - COMPENSATION

2.1 The reserving party shall pay the supplying party:-

2.11 Demand Charge

2.111 When Kentucky Company is the supplying party:-

For the billing demand for each month at the rate of $6.50 per kilowatt for such month.

2.112 When East Kentucky is the supplying party:-

For the billing demand for each month at the rate of $5.50 per kilowatt for such month.

2.12 for each kilowatt of the reserved Limited Term Power that is purchased by the supplying party from a Third Party, (a) the excess, if any, of the amount paid therefor by the supplying party over the charge therefor under subsection 2.11 of this Schedule (or, if such amount is less than such charge, minus the deficiency) plus (b) for each month such Limited Term Power is reserved, $1.00 per kilowatt; plus

2.13 110% of the out-of-pocket cost (including all operating, maintenance, tax, transmission losses and other expenses incurred that would not have been incurred if the energy had not been supplied) of supplying Limited Term Energy called for during such period that is generated by the supplying party's system; plus

2.14 for each kilowatthour purchased by the supplying party from a third party to supply Limited Term Energy called for during such period, 100% of the amount paid therefor by the supplying party plus 1 mill plus transmission losses and taxes incurred.

SERVICE SCHEDULE H
FUEL CONSERVATION ENERGY

Under Agreement dated May 14, 1963

between

EAST KENTUCKY POWER COOPERATIVE, INC.

and

KENTUCKY POWER COMPANY

FUEL CONSERVATION ENERGY

Fuel Conservation Energy shall be considered to be electric energy that is scheduled between the systems of the parties solely for the purpose of meeting an energy shortage which is caused by curtailments of energy sources which result from fuel unavailability, governmental actions or widespread disasters, any one of which is beyond control of the parties, making it necessary for the deficient system to conserve energy resources over an extended period of time. The following are the terms and conditions governing the generation and supply of such Energy by one system for the other, and also the transmission of Fuel Conservation Energy to and from other systems interconnected with the parties hereto. As used herein the term "week" shall mean any seven consecutive days.

Section 1 - Services To Be Rendered

1.1 Either party may arrange with the other, for periods of one or more weeks, for the delivery of Fuel Conservation Energy. The parties shall determine the number of megawatts per hour to be supplied, the period of supply, the estimated cost and the source of supply if the supplying party is in turn obtaining it from another system or the ultimate destination if a party is in turn arranging for the supply for another system.

1.2 During each weekly period for which Fuel Conservation Energy has been arranged, the party that has agreed to supply such Energy will, upon call, deliver megawatt-hours to the receiving party in amounts up to and including the number of megawatt-hours equal to the product of the period of supply in hours and the number of megawatts then arranged for, at a rate of delivery which is agreeable to the parties. After arrangements for Fuel Conservation Energy have been made the deliveries may be reduced only when conditions arise that could not have been reasonably foreseen at the time of the arrangement and cause the arrangement to be burdensome to the supplying, receiving or transmitting systems.

Section 2 - Compensation

2.1 For each kilowatt-hour of Fuel Conservation Energy that is purchased by the supplying party from another system for delivery to the receiving party, the receiving party shall pay the supplying party the amount paid therefor by the supplying party plus:

(a) If the receiving party is Kentucky Company, Kentucky Company shall pay East Kentucky 1.7 mills per kilowatt-hour for each kilowatt-hour received plus or minus an adjustment for transmission losses.

(b) If the receiving party is East Kentucky, East Kentucky shall pay Kentucky Company 1.7 mills per kilowatt-hour for each kilowatt-hour received plus or minus an adjustment for transmission losses.

2.2 For each kilowatt-hour of Fuel Conservation Energy that is generated by the supplying party:

(a) If the receiving party is Kentucky Company, Kentucky Company shall pay East Kentucky an amount equal to 6 mills per kilowatt-hour for generation, plus 1.7 mills per kilowatt-hour for transmission to the point of interconnection, plus the incremental energy costs, plus or minus an adjustment for transmission losses, plus 2 mills per kilowatt-hour.

(b) If the receiving party is East Kentucky, East Kentucky shall pay Kentucky Company an amount equal to 6 mills per kilowatt-hour for generation, plus 1.7 mills per kilowatt-hour for transmission to the point of interconnection, plus the incremental energy costs, plus or minus an adjustment for transmission losses, plus 2 mills per kilowatt-hour.

2.3 For purposes of subsections 2.2(a) and 2.2(b) of this Schedule, incremental energy costs mean out-of-pocket costs (including all operating, maintenance, tax, transmission losses and other expenses incurred that woul not have been incurred if the energy had not been supplied) of generating such Energy plus or minus an adjustment (to be made by supplemental bill) to reflect increases or decreases in the cost of fuel on a Btu basis between the cost of fuel at the stations from which the Energy was delivered during the month the Energy was delivered and the cost of such fuel for the second month after such month of delivery; provided, however, that in circumstances in which the supplying party anticipates that it will be unable, despite diligent efforts, to ascertain the replacement cost of fuel until a date subsequent to the second month after the month of delivery, and notification is provided in writing by the supplying party to the receiving party, such adjustment shall be made by supplemental bill whenever such replacement cost of fuel becomes available, unless the receiving party consents to an extension permitting supplemental billing at some later time.

2.4 For purposes of Sections 2.1 and 2.2 of this Schedule, cost adjustments for transmission losses shall be determined contemporaneously with the transactions based on the cost of generating the energy to make up the losses associated with the delivery of Fuel Conservation Energy.

2.5 Fuel Conservation Energy shall be accorded a dispatch priority between Short Term Energy and Economy Energy.

EXHIBIT

DEVELOPMENT OF TRANS SSION COSTS
BASED ON FPC-1 1979

	APPALACHIAN POWER COMPANY	OHIO COMPANY	INDIANA & MICHIGAN ELECTRIC COMPANY	KENTUCKY POWER COMPANY	TOTAL AEP SYSTEM	SOURCE
1) Total Transmission Plant Account	$460,334,506	558,300,349	424,731,285	69,583,290	1,512,949,430	1979 FPC-1 p402, L53 Col.(B+G) ÷ 2
2) Carrying Charge %	17.02	16.79	17.47	17.50		EXHIBIT A-I
3) Annual Investment Cost	78,348,933	93,738,629	74,200,555	12,177,076	258,465,193	(1) x (2)
4) Total Transmission Operation and Maintenance Expense	9,534,500	11,206,308	8,167,987	1,527,140	30,435,935	1979 FPC-1 p418 L99
5) Annual Total Transmission Cost	87,883,433	104,944,937	82,368,542	13,704,216	288,901,128	(3) + (4)
6) Demonstrated Cap (KW)*	5,226,000	6,126,000	3,998,000	1,023,000	16,373,000	1979 FPC-1 p431 Col. B
7) Transmission Cost/KW	16.82	17.13	20.60	13.40	17.65	(5) ÷ (6)
8) Transmission Cost Mills/kWh	1.92	1.96	2.35	1.53	2.01	(7) ÷ 8760

*The demonstrated capability has been developed, per Staff's instructions, solely for purposes of settlement. This computation is being submitted on the explicit understanding pursuant to Section 1.18(e) of the Commission's Rules of Practice and Procedure, that all offers of settlement are and shall be priviledged and shall be without prejudice to the position of any party in connection with this proceeding. The submission of this calculation establishes no principles and shall not be deemed, in any respect, to constitute an admission by the AEP System Companies that such calculations are true or valid.

APPROPRIATE ANNUAL CARRYING CHARGES
BASED UPON TWELVE ONTHS ENDING
DECEMBER 31, 1979

	EMBEDDED				INCREMENTAL			
COMPONENT	A	I	O	K	A	I	O	K
1/ COST OF MONEY	10.185%	10.387%	9.998%	10.367	12.460%	12.394%	12.362%	12.655
2/ DEPRECIATION	1.354	1.344	1.364	1.345	1.261	1.263	1.265	1.255
3/ FEDERAL INCOME TAX	3.478	3.738	3.428	3.783	3.729	4.021	3.692	3.884
4/ OTHER	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
TOTAL	17.017	17.469	16.790	17.495	19.450	19.678	19.319	19.794

1/ See pages 2, 3, 4 and 5

2/ Sinking fund factor with provision for R_1 dispersion 33-year life (i^Bd)

3/ $T\% = t/1-t\ (i + i^Bd - o^d)(1 - Bb/i)(.9)$

Where t = corporate tax rate (46%)
i_d = cost of money
o^d = straight line depreciation, 33-year life

B = Capitalization ratio of Debt
b = Debt Rate
.9 = provision for accelerated depreciation

4/ Includes Insurance, General Administration and taxes other than Federal.

he components listed above are of necessity approximations and it is not intended to indicate that ome components will or should be fixed, at all times or at any given figure, i.e., particular com- onents may vary from time to time. The rate for Short Term Service is negotiated at arms-length nd the carrying charges as specified herein and the cost of money utilized is acceptable only as o these types of transactions, and the publishing by the AEP System Companies of the carrying charge ate or the cost of money component thereof is not necessarily to be deemed adequate or reasonable or any other types of service.

K - Kentucky Power Company
- Appalachian Power Company I - Indiana & Michigan Electric Company O - Ohio Power Company

CARRYING CHARGE DEVELOPMENT*

Appalachian Power Company (A)
Calculation of Capitalization Ratio

	$000's
Debt	1,099,199
Preferred Stock	148,437
Common Equity	694,660
Total	1,942,296

a) Debt Ratio = $\frac{1,099,199}{1,942,296}$ = 56.59%

b) Preferred Ratio = $\frac{148,437}{1,942,296}$ = 7.64%

c) Common Equity = $\frac{694,660}{1,942,296}$ = 35.77%

Cost of Money

	Embedded			Incremental		
Equity	35.77% @ 13.50% 1/	= 4.829%	35.77%	@ 13.5%		= 4.829%
Preferred	7.64% @ 7.88% 2/	0.602%	7.64%	@ 11.0%	3/	= 0.840%
Debt	56.59% @ 8.40% 2/	4.754%	56.59%	@ 12.0%	3/	= 6.791%
Total	100.00%	10.185	100.00%			12.460%

1/ Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{11,704}{148,437}$ = 7.88%

2/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{92,374}{1,099,199}$ = 8.40%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79

CARRYING CHARGE DEVELOPMENT*

II. Indiana & Michigan (I)
Calculation of Capitalization Ratios

	$000's
Debt	1,088,222
Preferred Stock	267,381
Common Equity	724,688
Total	2,080,291

a) Debt Ratio = $\frac{1,088,222}{2,080,291}$ = 52.31%

b) Preferred Ratio = $\frac{267,381}{2,080,291}$ = 12.85%

c) Common Equity = $\frac{724,688}{2,080,291}$ = 34.84%

Cost of Money

	Embedded			Incremental		
Equity	34.84%	@13.50%	= 4.703%	34.84%	@ 13.5% 3/	= 4.703%
Preferred	12.85%	@ 8.69% 1/	= 1.117%	12.85%	@ 11.0% 3/	= 1.414%
Debt	52.31%	@ 8.73% 2/	= 4.567%	52.31%	@ 12.0% 3/	= 6.277%
Total	100.00%		10.387%	100.00%		12.394%

1/ Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{23,237}{267,381}$ = 8.69%

2/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{94,992}{1,088,222}$ = 8.73%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79

CARRYING CHARGE DEVELOPMENT*

III. Ohio Power Consolidated (O)
Calculation of Capitalization Ratios

	$000's
Debt	1,495,061
Preferred Stock	313,921
Common Equity	851,475
Total	2,660,457

a) Debt Ratio = $\frac{1,495,061}{2,660,457}$ = 56.20%

b) Preferred Ratio = $\frac{313,921}{2,660,457}$ = 11.80%

c) Common Equity = $\frac{851,475}{2,660,457}$ = 32.00%

Cost of Money

	Embedded			Incremental		
Equity	32.00% @ 13.50%		= 4.320%	32.00% @ 13.5%	3/	= 4.320%
Preferred	11.80% @ 8.87%	1/	= 1.047%	11.80% @ 11.0%	3/	= 1.298%
Debt	56.20% @ 8.24%	2/	= 4.631%	56.20% @ 12.0%	3/	= 6.744%
Total	100.00%		9.998%	100.00%		12.362%

1/ Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{27,851}{313,921}$ = 8.87%

2/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{123,144}{1,495,061}$ = 8.24%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79.

CARRYING CHARGE DEVELOPMENT*

IV. Kentucky Power Company

Calculation of Capitalization Ratios

	$000's
Debt	186,288
Common Equity	144,298
Total	330,586

a) Debt Ratio = $\frac{186,288}{330,586}$ = 56.35%

b) Common Equity = $\frac{144,298}{330,586}$ = 43.65%

Cost of Money

	Embedded				Incremental			
Equity	43.65%	@ 13.50%		= 5.893%	43.65%	@ 13.50%		= 5.893%
Debt	56.35%	@ 7.94%	1/	= 4.474%	56.35%	@ 12.00%	2/	= 6.762%
Total	100.00%			10.367%	100.00%			12.655%

1/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{14,786}{186,288} = 7.94\%$

2/ Highest Rate paid in calendar year 1979

* Based upon capitalization data in financial reporting for twelve months ending 12/31/79

UNIT PARTICIPATION IN SHORT TERM SALES FOR 12-MONTH PERIOD ENDING JUNE 30, 1981
13.5% ROE

	(1) GEN & TRAN INVESTMENT COST/KW	(2) CARRYING CHARGE RATE %	(3) PARTICIPATION IN SHORT TERM SALES MWH	(4) %	(5) WEIGHTED ANNUAL COST/KW (1)x(2)x(4)	(6) FIXED G & T EXPENSES/KW	(7) WEIGHTED ANNUAL EXPENSES/KW (6)x(4)
AMOS	337.59	.1749	2,245,692	18.96	11.19	7.00	1.33
GLEN LYN	301.07	.1749	254,099	2.14	1.13	10.72	.23
SPORN	339.94	.1702	343,253	2.89	1.67	11.79	.34
KANAWHA	289.26	.1749	83,009	.75	.38	10.72	.08
CLINCH	285.35	.1749	143,065	1.30	.65	8.50	.11
BIG SANDY	256.87	.1804	89,160	.75	.35	9.48	.07
TAN CREEK	382.95	.1741	1,290,925	10.95	7.30	12.92	1.41
BREED	469.09	.1741	18,673	.15	.12	11.88	.02
GAVIN	343.58	.1702	5,009,573	42.29	24.73	7.03	2.97
MUSKINGUM	312.80	.1702	114,756	.96	.51	11.49	.11
KAMMER	368.31	.1702	16,917	.14	.09	13.96	.02
CARDINAL	361.49	.1702	282,645	2.38	1.46	15.61	.37
MITCHELL	349.28	.1702	515,843	4.35	2.59	8.52	.37
MOUNTAINEER	587.03	.1749	601,541	5.17	5.31	6.51	.34
CONESVILLE	447.48	.1896	227,199	1.91	1.62	24.28	.46
CONESVILLE 4	286.26	.1896	6,667	.05	.03	13.16	.01
POSTON	350.27	.1896	2,641	.02	.01	18.59	.00
PICKWAY	316.19	.1896	2,702	.02	.01	24.22	.00
BECKJORD	303.07	.1896	12,475	.10	.06	13.23	.01
STUART	322.10	.1896	293,200	2.52	1.54	11.06	.28
WALNUT	151.07	.1896	25,217	.21	.06	7.96	.02
SMITH MTN	277.64	.1749	236.754	1.99	.97	3.94	.08
TOTAL			11,843,006	100.00	61.78		8.63

TOTAL ANNUAL COST (5) + (7) = $61.78 + $8.63 = $70.41

WEEKLY DEMAND CHARGE (TOTAL ANNUAL COST/52) $70.41/52 = $ 1.35

I.A.D.
9/21/81

UNIT PARTICIPATION IN LIMITED TERM SALES
FOR 12-MONTH PERIOD ENDING JUNE 30, 1981
13.5% ROE

	(1) GEN & TRAN INVESTMENT COST/KW	(2) CARRYING CHARGE RATE %	(3) PARTICIPATION IN SHORT TERM SALES MWH	(4) %	(5) WEIGHTED ANNUAL COST/KW (1)x(2)x(4)	(6) FIXED G & T EXPENSES/KW	(7) WEIGHTED ANNUAL EXPENSES/KW (6)x(4)
AMOS	381.46	.1749	733,718	15.51	10.35	7.90	1.23
CLINCH RIVER	318.77	.1749	151,189	3.20	1.78	9.70	.31
GLEN LYN	337.63	.1749	129,653	2.74	1.62	12.37	.34
KANAWHA	323.46	.1749	59,279	1.25	.71	12.37	.15
MOUNTAINEER	680.79	.1749	515,200	10.89	12.97	7.32	.80
SPORN	385.59	.1702	227,418	4.81	3.16	13.55	.65
BIG SANDY	289.11	.1804	73,336	1.55	.81	10.96	.17
BREED	537.24	.1741	22,024	.47	.44	13.77	.06
TAN CREEK	433.87	.1741	80,206	1.70	1.28	15.02	.26
CARDINAL	411.45	.1702	206,775	4.38	3.07	18.13	.79
GAVIN	389.96	.1702	2,024,328	42.80	28.41	7.84	3.36
KAMMER	419.64	.1702	28,422	.60	.43	16.15	.10
MITCHELL	396.80	.1702	154,609	3.27	2.21	9.62	.31
MUSKINGUM	353.03	.1702	82,815	1.75	1.05	13.19	.23
CONESVILLE	513.01	.1896	63,899	1.35	1.31	28.67	.39
CONESVILLE 4	319.55	.1896	6,629	.14	.08	15.33	.02
POSTON	396.36	.1896	2,892	.06	.05	21.85	.01
PICKWAY	355.47	.1896	3,804	.08	.05	28.60	.02
BECKJORD	339.72	.1896	3,427	.07	.05	15.41	.01
STUART	362.56	.1896	99,081	2.09	1.44	12.81	.27
SMITH MTN	309.52	.1749	60,985	1.29	.70	4.23	.05
TOTAL			4,729,689	100.00	71.97		9.53

TOTAL ANNUAL COST (5) + (7) = $71.97 + $9.53 = $81.50

MONTHLY DEMAND CHARGE (TOTAL ANNUAL COST/12) $81.50/12 = $ 6.79

SHORT TERM SALES
GENERATION AND TRANSMISSION PLANT COST/KW
($/KW)

	GENERATION PLANT COST ($/KW)	TRANSMISSION PLANT COST ($/KW)	TOTAL G&T INVESTMENT COST ($/KW)
AMOS	219.34	118.25 (a)	337.59
GLEN LYN	182.82	118.25 (a)	301.07
SPORN	228.27	111.67 (d)	339.94
KANAWHA	171.01	118.25 (a)	289.26
CLINCH RIVER	167.10	118.25 (a)	285.35
SMITH MT	159.39	118.25 (a)	277.64
BIG SANDY	161.19	95.68 (b)	256.87
TANNERS CREEK	254.61	128.34 (c)	382.95
BREED	340.75	128.34 (c)	469.09
GAVIN	231.91	111.67 (d)	343.58
MUSKINGUM	201.13	111.67 (d)	312.80
KAMMER	256.64	111.67 (d)	368.31
CARDINAL	249.82	111.67 (d)	361.49
MITCHELL	237.61	111.67 (d)	349.28
MOUNTAINEER	468.78	118.25 (a)	587.03
CONESVILLE	327.65	119.83 (e)	447.48
POSTON	230.44	119.83 (e)	350.27
PICWAY	196.36	119.83 (e)	316.19
BECKJORD	183.24	119.83 (e)	303.07
STUART	202.27	119.83 (e)	322.10
CONESVILLE #4	166.43	119.83 (e)	286.26
WALNUT	31.24	119.83 (e)	151.07

SOURCE - 1980 FPC-1

GENERATION PLANT COST - p432 Line 17/Line 9

TRANSMISSION COST - (a) p402 L53/APCO p424-D Feb.
(b) p402 L53/KPCO p424-D Mar.
(c) p402 L53/I&M p424-F Feb.
(d) p402 L53/OPCO p424-J Feb.
(e) p402 L53/CSOE p431 L37.

SHORT TERM SALES
FIXED PLANT EXPENSES

	PRODUCTION ($/KW)	TRANSMISSION ($/KW)	TOTAL (1) + (2)
AMOS	4.52	2.48 (a)	7.00
GLEN LYN	8.24	2.48 (a)	10.72
SPORN	8.79	3.00 (d)	11.79
KANAWHA	8.24	2.48 (a)	10.72
CLINCH RIVER	6.02	2.48 (a)	8.50
SMITH MT	1.46	2.48 (a)	3.94
BIG SANDY	7.40	2.08 (b)	9.48
TANNERS CREEK	10.48	2.44 (c)	12.92
BREED	9.44	2.44 (c)	11.88
GAVIN	4.03	3.00 (d)	7.03
MUSKINGUM	8.49	3.00 (d)	11.49
KAMMER	10.96	3.00 (d)	13.96
CARDINAL	12.61	3.00 (d)	15.61
MITCHELL	5.52	3.00 (d)	8.52
MOUNTAINEER	4.03*	2.48 (a)	6.51
CONESVILLE	21.96	2.32 (e)	24.28
POSTON	16.27	2.32 (e)	18.59
PICWAY	21.90	2.32 (e)	24.22
BECKJORD	10.91	2.32 (e)	13.23
STUART	8.74	2.32 (e)	11.06
CONESVILLE #4	10.84	2.32 (e)	13.16
WALNUT	5.64	2.32 (e)	7.96

SOURCE - 1980 FPC-1

PRODUCTION EXPENSE - p432 (Line 34 - ½ Line 29 thru 33)/L9

TRANSMISSION EXPENSE - (a) p418 L99/APCO p424-D Feb.
(b) p418 L99/KPCO p424-D Mar.
(c) p418 L99/I&M p424-F Feb.
(d) p418 L99/OPCO p424-J Feb.
(e) p418 L99/CSOE p431 L37.

*Mountaineer was not in operation entire year, Gavin expenses are used.

LIMITED TERM SALES
GENERATION AND TRANSMISSION PLANT COST/KW
($/KW)

	GENERATION PLANT COST ($/KW)	TRANSMISSION PLANT COST ($/KW)	TOTAL G&T INVESTMENT COST ($/KW)
AMOS	263.21	118.25 (a)	381.46
GLEN LYN	219.38	118.25 (a)	337.63
SPORN	273.92	111.67 (d)	385.59
KANAWHA	205.21	118.25 (a)	323.46
CLINCH RIVER	200.52	118.25 (a)	318.77
SMITH MT	191.27	118.25 (a)	309.52
BIG SANDY	193.43	95.68 (b)	289.11
TANNERS CREEK	305.53	128.34 (c)	433.87
BREED	408.90	128.34 (c)	537.24
GAVIN	278.29	111.67 (d)	389.96
MUSKINGUM	241.36	111.67 (d)	353.03
KAMMER	307.97	111.67 (d)	419.64
CARDINAL	299.78	111.67 (d)	411.45
MITCHELL	285.13	111.67 (d)	396.80
MOUNTAINEER	562.54	118.25 (a)	680.79
CONESVILLE	393.18	119.83 (e)	513.01
POSTON	276.53	119.83 (e)	396.36
PICWAY	235.64	119.83 (e)	355.47
BECKJORD	219.89	119.83 (e)	339.72
STUART	242.73	119.83 (e)	362.56
CONESVILLE #4	199.72	119.83 (e)	319.55

SOURCE - 1980 FPC-1

GENERATION PLANT COST - p432 (Line 17/Line 9) x 1.20 to allow for 20% Reserve

TRANSMISSION COST - (a) p402 L53/APCO p424-D Feb.
(b) p402 L53/KPCO p424-D Mar.
(c) p402 L53/I&M p424-F Feb.
(d) p402 L53/OPCO p424-J Feb.
(e) p402 L53/CSOE p431 L37.

LIMITED TERM SALES
FIXED PLANT EXPENSES

	PRODUCTION ($/KW)	TRANSMISSION ($/KW)	TOTAL (1) + (2)
AMOS	5.42	2.48 (a)	7.90
GLEN LYN	9.89	2.48 (a)	12.37
SPORN	10.55	3.00 (d)	13.55
KANAWHA	9.89	2.48 (a)	12.37
CLINCH RIVER	7.22	2.48 (e)	9.70
SMITH MT	1.75	2.48 (e)	4.23
BIG SANDY	8.88	2.08 (b)	10.96
TANNERS CREEK	12.58	2.44 (c)	15.02
BREED	11.33	2.44 (c)	13.77
GAVIN	4.84	3.00 (d)	7.84
MUSKINGUM	10.19	3.00 (d)	13.19
KAMMER	13.15	3.00 (d)	16.15
CARDINAL	15.13	3.00 (d)	18.13
MITCHELL	6.62	3.00 (d)	9.62
MOUNTAINEER	4.84*	2.48 (a)	7.32
CONESVILLE	26.35	2.32 (e)	28.67
POSTON	19.53	2.32 (e)	21.85
PICWAY	26.28	2.32 (e)	28.60
BECKJORD	13.09	2.32 (e)	15.41
STUART	10.49	2.32 (e)	12.81
CONESVILLE #4	13.01	2.32 (e)	15.33

SOURCE - 1980 FPC-1

PRODUCTION EXPENSE - p432 ((Line 34 - ½ Line 29 thru 33)/L9) x 1.20 to provide for 20% Reserves

TRANSMISSION EXPENSE - (a) p418 L99/APCO p424-D Feb.
(b) p418 L99/KPCO p424-D Mar.
(c) p418 L99/I&M p424-F Feb.
(d) p418 L99/OPCO p424-J Feb.
(e) p418 L99/CSOE p431 L37.

*Mountaineer was not in operation entire year, Gavin expenses are used.

APPROPRIATE ANNUAL CARRYING CHARGES
BASED UPON TWELVE MONTHS ENDING
DECEMBER 31, 1980

EMBEDDED
13.5% ROE

COMPONENT	A	I	O	K	C
COST OF MONEY	10.643	10.502	10.281	10.915	11.430
DEPRECIATION	1.332	1.339	1.349	1.324	1.298
FEDERAL INCOME TAX	3.517	3.570	3.392	3.804	4.227
OTHER	2.000	2.000	2.000	2.000	2.000
TOTAL	17.492	17.411	17.022	18.043	18.955

1) See pages 2, 3, 4, 5 and 6.

2) Sinking fund factor with provision for R_1 dispersion 33-year life ($i^B d$)

3) $T\% = T/1\text{-}t\ (i + i^B d - o^d)\ (1 - Bb/i)\ (.9)$

Where t = corporate tax rate (46%) B = Capitalization ratio debt
i_d = cost of money b = Debt rate
o^d = straight line depreciation, 33-year life
.9 = provision for accelerated depreciation

4) Includes Insurance, General Administration and taxes other than Federal, gross receipts, sales or use taxes

The components listed above are of necessity approximations and it is not intended to indicate that some components will or should be fixed at all times or at any given figure, i.e., particular components may vary from time to time. Rates for Service are negotiated at arms-length and the carrying charges as specified herein and the cost of money utilized is acceptable only as to these transactions.

A - Appalachian Power Company I - Indiana & Michigan Electric Company
O - Ohio Power Company K - Kentucky Power Company
C - Columbus and Southern Ohio Electric Company

CARRYING CHARGE DEVELOPMENT*

I. Appalachian Power Company (A) Calculation of Capitalization Ratio

	$000's		
Debt	1,220,455		
Preferred Stock	146,947		
Common Equity	782,164		
Total	2,149,566		
a) Debt Ratio	1,220,455 / 2,149,566	=	56.77
b) Preferred Ratio	146,947 / 2,149,566	=	6.84
c) Common Equity	782,164 / 2,149,566	=	36.39

Cost of Money

	Embedded					Incremental				
Equity	36.39%	@	13.50% [1]	=	4.913%	36.39%	@	13.5% [3]	=	4.913%
Preferred	6.84%	@	7.99% [2]	=	0.547%	6.84%	@	14.0% [3]	=	0.958%
Debt	56.77%	@	9.13% [2]	=	5.183%	56.77%	@	14.0% [3]	=	13.948%
Total	100.00%				10.643%	100.00%				13.819%

1) Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{11,741}{146,947} = 7.99\%$

2) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{111,456}{1,220,455} = 9.13\%$

3) Highest Rate paid in calendar year 1980

*Based upon capitalization data in financial reporting for twelve months ending 12/31/80.

CARRYING CHARGE DEVELOPMENT*

I. Indiana & Michigan (I)
Calculation of Capitalization Ratio

	$000's	
Debt	1,241,884	
Preferred Stock	264,000	
Common Equity	761,605	
Total	2,267,489	
a) Debt Ratio	1,241,884 / 2,267,489	= 54.77
b) Preferred Ratio	264,000 / 2,267,489	= 11.64
c) Common Equity	761,605 / 2,267,489	= 33.59

Cost of Money

	Embedded			Incremental		
Equity	33.59% @ 13.50%[1]	= 4.535%	33.59%	@ 13.5%[3]	= 4.535%
Preferred	11.64% @ 8.73%[2]	= 1.016%	11.64%	@ 14.0%[3]	= 1.630%
Debt	54.77% @ 9.04%[2]	= 4.951%	54.77%	@ 14.0%[3]	= 7.668%
Total	100.00%	10.502%	100.00%		13.833%

1) Preferred Rate = Annualized Dividends / Preferred Outstanding = 23,058 / 264,000 = 8.74%

2) Debt Rate = Annualized Interest / Debt Outstanding = 112,280 / 1,241,884 = 9.04%

3) Highest Rate paid in calendar year 1980

*Based upon capitalization data in financial reporting for twelve months ending 12/31/80.

CARRYING CHARGE DEVELOPMENT*

I. Ohio Power Consolidated (O)
Calculation of Capitalization Ratio

	$000's
Debt	1,541,082
Preferred Stock	308,490
Common Equity	864,114
Total	2,713,686

a) Debt Ratio $\frac{1,541,082}{2,713,686}$ = 56.79

b) Preferred Ratio $\frac{308,490}{2,713,686}$ = 11.37

c) Common Equity $\frac{864,114}{2,713,686}$ = 31.84

Cost of Money

	Embedded				Incremental		
Equity	31.84%	@ 13.50%	= 4.298%	31.84%	@ 13.5%	= 4.298%
Preferred	11.37%	@ 8.72%[1]	= 0.991%	11.37%	@ 14.0%	= 1.592%
Debt	56.79%	@ 8.79%[2]	= 4.992%	56.79%	@ 14.0%	= 7.951%
Total	100.00%		10.281%	100.00%		13.841%

1) Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{26,905}{308,490}$ = 8.72%

2) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{135,424}{1,541,082}$ = 8.79%

*Based upon capitalization data in financial reporting for twelve months ending 12/31/80.

CARRYING CHARGE DEVELOPMENT*

I. Kentucky Power Company (K)
Calculation of Capitalization Ratio

	$000's	
Debt	185,517	
Common Equity	143,190	
Total	328,707	
a) Debt Ratio	185,517 / 328,707	= 56.44
b) Common Equity	143,190 / 328,707	= 43.56

Cost of Money

	Embedded				Incremental		
Equity	43.56%	@ 13.50%[1]	= 5.881%	43.56%	@ 13.50%[2]	= 5.881%
Debt	56.44%	@ 8.92%	= 5.034%	56.44%	@ 14.00%	= 7.902%
Total	100.00%		10.915%	100.00%		13.783%

1) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{16,541}{185,517} = 8.92\%$

2) Highest Rate paid in calendar year 1980

*Based upon capitalization data in financial reporting for twelve months ending 12/31/80.

CARRYING CHARGE DEVELOPMENT*

I. Columbus and Southern Ohio Electric Company (C) Calculation of Capitalization Ratio

	$000's
Debt	651,783
Preferred Stock	154,918
Common Equity	463,744
Total	1,270,445

a) Debt Ratio $\frac{651,783}{1,270,445} = 51.30$

b) Preferred Ratio $\frac{154,918}{1,270,445} = 12.20$

c) Common Equity $\frac{463,744}{1,270,445} = 36.50$

Cost of Money

	Embedded				Incremental			
Equity	36.50%	@ 13.50%	=	4.927%	36.50%	@ 13.5%	=	4.927%
Preferred	12.20%	@ 12.89%[1]	=	1.573%	12.20%	@ 14.0%	=	1.708%
Debt	51.30%	@ 9.61%[2]	=	4.930%	51.30%	@ 14.0%	=	7.182%
Total	100.00%			11.430%	100.00%			13.817%

1) Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}} = \frac{19,964}{154,918} = 12.89\%$

2) Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}} = \frac{62,657}{651,783} = 9.61\%$

*Based upon capitalization data in financial reporting for twelve months ending 12/31/80.

SHORT TERM AND LIMITED TERM TRANSMISSION SERVICE DEMAND RATE COST - ANALYSIS BASED ON FPC-1 DATA AS OF DECEMBER 31, 1978

		Appalachian	Indiana Consolidated	Ohio Consolidated	Source (See page
(1)	Transmission Plant ($)	$431,601,113	$421,644,448	$556,019,771	(D)
(2)	Demonstrated Capability (MW)	4,329	3,317	4,848	(E)
(3)	Transmission Plant/kW ($/kW) (1) ÷ (2)	99.700	127,116	114.691	
(4)	1978 Transmission Expense ($)	9,145,316	6,457,887	9,509,467	(F)
(5)	Transmission Expense/kW ($/kW) (4) ÷ (2)	2.113	1.947	1.962	
(6)	Transmission Demand Rate/kW week ($)	0.24	0.24	0.24	
[(7)	Transmission Demand Rate/kW month ($)	1.00	1.00	1.00]	
(8)	Transmission Demand Rate/kW year ($)(6)x52	12.48	12.48	12.48	
(9)	Yearly Transmission Demand Rate less Transmission Expense ($) (8) - (5)	10.367	10.533	10.518	
(10)	Annual Carrying Charge on Investment (%) (9) ÷ (3)	10.398%	8.286%	9.171%	

TP
10/19/79

SOURCE FOR SHORT TERM AND LIMITED TERM
SERVICE COST ANALYSIS

Source*

(A) 1978 FPC-1, p. 401, lines 15 and 23.

(B) 1978 FPC-1, starting from p. 432 line 9 (summation of all plants)

(C) 1978 FPC-1, p. 417, (line 20-line 5-½ line 19)**

(D) 1978 FPC-1, p. 402, line 53

(E) 1978 FPC-1, p. 424 D or F - Maximum Twelve Month Peak Demand in the Summary of Primary Capacity for System Accounts

(F) 1978 FPC-1, p. 418 - 419, line 99

*Items (A), (B), (C), (D) and (F) for Ohio are consolidated from FPC-1 reports for Ohio Power Company and Ohio Electric Company.

**Item (C) for Indiana & Michigan Power Company portion of I&M Consol. is from FPC-1 report p. 417, (Line 40-line 24-½ line 39)

BASED ON UNIT PARTICIPATION IN SHORT TERM SALES
FOR 1980 YEAR TO DATE

GENERATING UNIT	(1) GEN & TRAN INVESTMENT COST/KW	(2) PARTICIPATION IN SHORT TERM MWH	(3) SALES %	(4) WEIGHTED INVESTMENT COST/KW (1) x (3)	(5) CARRYING CHARGE RATE %	(6) WEIGHTED ANNUAL INVESTMENT COST/KW (4) x (5)
AMOS	220.94	495,436	8.94	19.75	.1702	3.36
GLEN LYN	181.34	218,698	3.95	7.16	.1702	1.22
SPORN	183.87	950,631	17.15	31.53	.1679	5.29
KANAWHA	168.84	49,642	.89	1.50	.1702	0.26
CLINCH	164.57	441,336	7.96	13.10	.1702	2.23
SMITH MTN	119.49	174,953	3.16	3.78	.1702	0.64
BIG SANDY	161.00	50,085	.90	1.45	.1750	0.25
TAN CREEK	251.18	820,872	14.81	37.20	.1747	6.50
BREED	333.43	16,379	.30	1.00	.1747	0.17
GAVIN	227.57	2,030,987	36.65	83.40	.1679	14.00
MUSKINGUM	156.88	42,791	.77	1.21	.1679	0.20
KAMMER	249.14	9,740	.18	.45	.1679	0.08
CARDINAL	145.55	154,050	2.78	4.05	.1679	0.68
MITCHELL	231.98	44,405	.80	1.86	.1679	0.31
MOUNTAINEER	476.15	42,107	.76	3.62	.1702	0.62
TOTAL		5,542,112	100.00	211.06		35.81

DEVELOPMENT OF FUEL CONSERVATION COSTS
BASED ON UNIT PARTICIPATIC)IN SHORT TERM SALES
FOR 1980, YEAR TO DATE

GENERATING UNIT	(1) WEIGHTED ANNUAL INVESTMENT COST/KW (PAGE 1)	(2) PARTICIPATION IN SHORT TERM SALES%	(3) FIXED G & T EXPENSES/KW	(4) WEIGHTED G & T EXPENSES/KW (2) x (3)	(5) PLANT AVAILABILITY (3YR. AVERAGE)	(6) DEMAND CHARGE MILLS/KWH $\frac{(1) + (4)}{8760} \div (5)$
AMOS	3.36	8.94	3.96	0.35	77.11	.549
GLEN LYN	1.22	3.95	8.79	0.35	76.15	.235
SPORN	5.29	17.15	9.19	1.58	58.66	1.337
KANAWHA	0.26	.89	8.23	0.07	81.94	.046
CLINCH	2.23	7.96	5.62	0.45	83.28	.367
SMITH MTN	0.64	3.16	1.33	0.04	95.00*	.082
BIG SANDY	0.25	.90	9.44	0.08	66.06	.057
TAN CREEK	6.50	14.81	9.14	1.35	60.66	1.477
BREED	0.17	.30	11.41	0.03	62.61	.036
GAVIN	14.00	36.65	3.95	1.45	80.53	2.190
MUSKINGUM	0.20	.77	6.02	0.05	74.16	.038
KAMMER	0.08	.18	8.17	0.01	76.28	.013
CARDINAL	0.68	2.78	11.17	0.31	63.74	.177
MITCHELL	0.31	.80	4.60	0.04	68.18	.059
MOUNTAINEER	0.62	.76	3.95	0.03	81.00*	.092
TOTAL	35.81	100.00		6.19	*Estimate	6.755

SHORT TERM SALES
GENERATION AND TRANSMISSION PLANT COST/KW
($/KW)

PLANT	GENERATION PLANT COST ($/KW)	TRANSMISSION PLANT COST ($/KW)	TOTAL G&T INVESTMENT COST ($/KW)
AMOS	220.94	108.85 (a)	329.79
GLEN LYN	181.34	108.85	290.19
SPORN	183.87	108.85	292.72
KANAWHA	168.84	108.85	277.69
CLINCH	164.57	108.85	273.42
SMITH MT	119.49	108.85	228.34
BIG SANDY	161.00	80.05 (b)	241.05
TANNERS CREEK	251.18	126.61 (c)	377.79
BREED	333.43	126.61	460.04
GAVIN	227.57	108.85 (d)	336.42
MUSKINGUM	156.88	108.85	265.73
KAMMER	249.14	108.85	357.99
CARDINAL	145.55	108.85	254.40
MITCHELL	231.98	108.85	340.83
MOUNTAINEER	476.15 (est.)	108.85 (a)	585.00

Source - 1979 FPC-1

Generation Plant Cost - p432 Line 17 ÷ Line 9

Transmission Cost - (a) p402 L53 ÷ APCO p424-D Feb.
(b) p402 L53 ÷ KPCO p424-D Mar.
(c) p402 L53 ÷ I&M p424-F Feb.
(d) p402 L53 ÷ OPCO p424-J Feb.

SHORT TERM SALES
FIXED PLANT EXPENSES

PLANT	PRODUCTION ($/KW)	TRANSMISSION ($/KW)	TOTAL (1) + (2)
AMOS	3.96	2.12 (a)	6.08
GLEN LYN	8.79	2.12 (a)	10.91
SPORN	9.19	2.18 (d)	11.37
KANAWHA	8.23	2.12 (a)	10.35
CLINCH	5.62	2.12 (a)	7.74
SMITH MT	1.33	2.12 (a)	3.45
BIG SANDY	9.44	1.74 (b)	11.18
TANNERS CREEK	9.14	2.42 (c)	11.56
BREED	11.41	2.42 (c)	13.83
GAVIN	3.95	2.18 (d)	6.13
MUSKINGUM	6.02	2.18 (d)	8.20
KAMMER	8.17	2.18 (d)	10.35
CARDINAL	11.17	2.18 (d)	13.35
MITCHELL	4.60	2.18 (d)	6.78
MOUNTAINEER	3.95	2.12 (a)	6.07

Source: 1979 FPC-1

Production Expense p432 (L34 - L21 - ½L29 thru 33) ÷ L9

Transmission Expense (a) p418 line 99 ÷ APCO p424-D Feb.
(b) p418 line 99 ÷ KPCO p424-D Mar.
(c) p418 line 99 ÷ I&M p424-F Feb.
(d) p418 line 99 ÷ OPCO p424-J Feb.

BASED ON UNIT PARTICIPATION IN SHORT TERM SALES
PROJECTE' 1981

GENERATING UNIT	(1) GEN & TRAN INVESTMENT COST/KW	(2) PARTICIPATION IN SHORT TERM MWH	(3) SALES %	(4) WEIGHTED INVESTMENT COST/KW (1) x (3)	(5) CARRYING CHARGE RATE %	(6) WEIGHTED ANNUAL INVESTMENT COST/KW (4) x (5)
AMOS	220.94	399,383	7.21	15.93	.1702	2.71
GLEN LYN	181.34	176,298	3.18	5.77	.1702	0.98
SPORN	183.87	766,327	13.83	25.43	.1679	4.27
KANAWHA	168.84	40,018	0.72	1.22	.1702	0.21
CLINCH	164.57	355,772	6.42	10.57	.1702	1.80
SMITH MTN	119.49	141,034	2.54	3.04	.1702	0.52
BIG SANDY	161.00	40,375	.73	1.18	.1750	0.21
TAN CREEK	251.18	661,725	11.94	29.99	.1747	5.24
BREED	333.43	13,204	.24	.80	.1747	0.14
GAVIN	227.57	1,637,229	29.54	67.22	.1679	11.29
MUSKINGUM	156.88	34,495	.62	.97	.1679	0.16
KAMMER	249.14	7,852	.14	.35	.1679	0.06
CARDINAL	145.55	124,184	2.24	3.26	.1679	0.55
MITCHELL	231.98	35,796	.65	1.51	.1679	0.25
MOUNTAINEER	476.15	1,108,420	20.00	95.23	.1702	16.21
TOTAL		5,542,112	100.00	262.47		44.60

DEVELOPMENT OF FUEL CONSERVATION COSTS
BASED ON UNIT PARTICIPATION IN SHORT TERM SALES
PROJECTED 1981

GENERATING UNIT	(1) WEIGHTED ANNUAL INVESTMENT COST/KW (PAGE 1)	(2) PARTICIPATION IN SHORT TERM SALES%	(3) FIXED G & T EXPENSES/KW	(4) WEIGHTED G & T EXPENSES/KW (2) x (3)	(5) PLANT AVAILABILITY (3YR. AVERAGE)	$\frac{(1) + (4)}{8760} \div (5)$
AMOS	2.71	7.21	3.96	0.29	77.11	.444
GLEN LYN	0.98	3.18	8.79	0.28	76.15	.189
SPORN	4.27	13.83	9.19	1.27	58.66	1.078
KANAWHA	0.21	0.72	8.23	0.06	81.94	.038
CLINCH	1.80	6.42	5.62	0.36	83.28	.296
SMITH MTN	0.52	2.54	1.33	0.03	95.00	.066
BIG SANDY	0.21	.73	9.44	0.07	66.06	.048
TAN CREEK	5.24	11.94	9.14	1.09	60.66	1.191
BREED	0.14	.24	11.41	0.03	62.61	.031
GAVIN	11.29	29.54	3.95	1.17	80.53	1.766
MUSKINGUM	0.16	.62	6.02	0.04	74.16	.031
KAMMER	0.06	.14	8.17	0.01	76.28	.010
CARDINAL	0.55	2.24	11.17	0.25	63.74	.143
MITCHELL	0.25	.65	4.60	0.03	68.18	.047
MOUNTAINEER	16.21	20.00	3.95	0.79	81.00	2.396
TOTAL	44.60	100.00		5.77		7.774

APPROPRIATE ANNUAL CARRYING CHARGES
BASED UPON TWELVE)NTHS ENDING
DECEMBER 31, 1979

EXHIBIT C-I
Page)of 5

OMPONENT	EMBEDDED A	EMBEDDED I	EMBEDDED O	EMBEDDED K	INCREMENTAL A	INCREMENTAL I	INCREMENTAL O	INCREMENTAL K
/ COST OF MONEY	10.185%	10.387%	9.998%	10.367	12.460%	12.394%	12.362%	12.655
/ DEPRECIATION	1.354	1.344	1.364	1.345	1.261	1.263	1.265	1.255
/ FEDERAL INCOME TAX	3.478	3.738	3.428	3.783	3.729	4.021	3.692	3.884
/ OTHER	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
TOTAL	17.017	17.469	16.790	17.495	19.450	19.678	19.319	19.794

1/ See pages 2, 3, 4 and 5

2/ Sinking fund factor with provision for R_1 dispersion 33-year life ($i^B d$)

3/ $T\% = t/1-t\ (i + i^B d - o^d)(1 - Bb/i)(.9)$

Where t = corporate tax rate (46%)
i_d = cost of money
o^d = straight line depreciation, 33-year life

B = Capitalization ratio of Debt
b = Debt Rate
.9 = provision for accelerated depreciation

4/ Includes Insurance, General Administration and taxes other than Federal.

ne components listed above are of necessity approximations and it is not intended to indicate that ome components will or should be fixed, at all times or at any given figure, i.e., particular com- onents may vary from time to time. The rate for Short Term Service is negotiated at arms-length nd the carrying charges as specified herein and the cost of money utilized is acceptable only as o these types of transactions, and the publishing by the AEP System Companies of the carrying charge ate or the cost of money component thereof is not necessarily to be deemed adequate or reasonable or any other types of service.

- Appalachian Power Company I - Indiana & Michigan Electric Company K - Kentucky Power Company O - Ohio Power Company

CARRYING CHARGE DEVELOPMENT*

I Appalachian Power Company (A)
Calculation of Capitalization Ratio

	$000's
Debt	1,099,199
Preferred Stock	148,437
Common Equity	694,660
Total	1,942,296

a) Debt Ratio = $\frac{1,099,199}{1,942,296}$ = 56.59%

b) Preferred Ratio = $\frac{148,437}{1,942,296}$ = 7.64%

c) Common Equity = $\frac{694,660}{1,942,296}$ = 35.77%

Cost of Money

	Embedded			Incremental		
Equity	35.77% @ 13.50% 1/	= 4.829%	35.77%	@ 13.5%		= 4.829%
Preferred	7.64% @ 7.88% 2/	0.602%	7.64%	@ 11.0%	3/	= 0.840%
Debt	56.59% @ 8.40% 2/	4.754%	56.59%	@ 12.0%	3/	= 6.791%
Total	100.00%	10.185	100.00%			12.460%

1/ Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}}$ = $\frac{11,704}{148,437}$ = 7.88%

2/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}}$ = $\frac{92,374}{1,099,199}$ = 8.40%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79

CARRYING CHARGE DEVELOPMENT*

II. Indiana & Michigan (I)
Calculation of Capitalization Ratios

	$000's
Debt	1,088,222
Preferred Stock	267,381
Common Equity	724,688
Total	2,080,291

a)	Debt Ratio	= =	1,088,222 / 2,080,291	= 52.31%
b)	Preferred Ratio	=	267,381 / 2,080,291	= 12.85%
c)	Common Equity	=	724,688 / 2,080,291	= 34.84%

Cost of Money

	Embedded			Incremental		
Equity	34.84%	@13.50%	= 4.703%	34.84%	@13.5% 3/	= 4.703%
Preferred	12.85%	@ 8.69% 1/	= 1.117%	~~12.85%~~	~~@11.0% 3/~~	~~= 1.414%~~
Debt	52.31%	@ 8.73% 2/	= 4.567%	52.31%	@12.0% 3/	= 6.277%
Total	100.00%		10.387%	100.00%		12.394%

1/ Preferred Rate = Annualized Dividends / Preferred Outstanding = 23,237 / 267,381 = 8.69%

2/ Debt Rate = Annualized Interest / Debt Outstanding = 94,992 / 1,088,222 = 8.73%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79

CARRYING CHARGE DEVELOPMENT*

I. Ohio Power Consolidated (O)
Calculation of Capitalization Ratios

	$000's
Debt	1,495,061
Preferred Stock	313,921
Common Equity	851,475
Total	2,660,457

a) Debt Ratio = $\frac{1,495,061}{2,660,457}$ = 56.20%

b) Preferred Ratio = $\frac{313,921}{2,660,457}$ = 11.80%

c) Common Equity = $\frac{851,475}{2,660,457}$ = 32.00%

Cost of Money

	Embedded			Incremental		
Equity	32.00%	@ 13.50%	= 4.320%	32.00%	@ 13.5% 3/	= 4.320%
Preferred	11.80%	@ 8.87% 1/	= 1.047%	11.80%	@ 11.0% 3/	= 1.298%
Debt	56.20%	@ 8.24% 2/	= 4.631%	56.20%	@ 12.0% 3/	= 6.744%
Total	100.00%		9.998%	100.00%		12.362%

1/ Preferred Rate = $\frac{\text{Annualized Dividends}}{\text{Preferred Outstanding}}$ = $\frac{27,851}{313,921}$ = 8.87%

2/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}}$ = $\frac{123,144}{1,495,061}$ = 8.24%

3/ Highest Rate paid in calendar year 1979

*Based upon capitalization data in financial reporting for twelve months ending 12/31/79.

CARRYING CHARGE DEVELOPMENT*

IV Kentucky Power Company

Calculation of Capitalization Ratios

	$000's
Debt	186,288
Common Equity	144,298
Total	330,586

a) Debt Ratio = $\frac{186,288}{330,586}$ = 56.35%

b) Common Equity = $\frac{144,298}{330,586}$ = 43.65%

Cost of Money

	Embedded		Incremental	
Equity	43.65% @ 13.50%	= 5.893%	43.65% @ 13.50%	= 5.893%
Debt	56.35% @ 7.94% 1/	= 4.474%	56.35% @ 12.00% 2/	= 6.762%
Total	100.00%	10.367%	100.00%	12.655%

1/ Debt Rate = $\frac{\text{Annualized Interest}}{\text{Debt Outstanding}}$ = $\frac{14,786}{186,288}$ = 7.94%

2/ Highest Rate paid in calendar year 1979

* Based upon capitalization data in financial reporting for twelve months ending 12/31/79

AEP'S

TRANSMISSION
As of 12/31/79

1.	AEP's Bulk Transmission ($000) 70% of Total Transmission	1,104,233
2.	Internal Peak Load (MW)	12,973
3.	Transmission Cost/kW ($/kW)	85.12
4.	Annual Cost using 18% CC (17% + 1% for Oper. & Maint.)	15.32
5.	Cost per hour in mills (4 ÷ 8760,i.e., 100% Load Factor)	1.749

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Kentucky Power Company) Docket No.

NOTICE OF FILING

Take notice that American Electric Power Service Corporation (AEP) on tendered for filing on behalf of its affiliate Kentucky Power Company (KPCO) Modification No. 2 dated May 1, 1982 to the Interconnection Agreement dated May 14, 1963 between East Kentucky Power Cooperative, Inc. and KPCO, KPCO's Rate Schedule FERC No. 14.

Section 1 of this agreement adds a Fuel Conservation Energy Service Schedule to the Interconnection Agreement and Section 2 modernizes the Billing and Payments Article of the Interconnection Agreement. Sections 3 and 4 of this Agreement update the Emergency Service and the Interchange Power Service Schedules. Sections 5 and 6 provide for an increase in the demand charge for Short Term and Limited Term Power to $1.25 per kilowatt per week and $6.50 per kilowatt per month respectively when KPCO is the supplying party and to $1.05 per kilowatt per week and $5.50 per kilowatt per month when KPCO is the supplying party. The transmission demand charge for Short Term and Limited Term Power has been increased to $0.24 per kilowatt per week and $1.00 per kilowatt per month respectively for both parties. The Short Term Power Service Schedule has also been revised to include a provision to allow for the sale of Short Term Power on a daily basis. The changes made in all of the service schedules in this Agreement are to comply with the Commissions Order 84 and to standardize the language of these Service Schedules with Service Schedules previously filed by American Electric Power Service Corporation and accepted for filing by the Commission. This Agreement is proposed to become effective May 1, 1982.

AEP requests an effective date of May 1, 1982 and therefor requests waiver of the Commission's notice requirements.

Copies of this filing were served upon East Kentucky Power Cooperative, Inc. and the Public Utilities Commission of Ohio.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 N. Capitol Street, Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commissions' Rules of Practice and Procedure (18 CFR

1.8, 1.10). All such petitions or protests should be filed on or before
Protests will be considered by the Commission in determining the appropriate action to be taken. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb
Secretary